EFFICIENT TRANSMISSION PRICING IN NORWAY AND SWEDEN

A Report for NVE

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The attached paper should not be interpreted as a general statement of "NERA policy" on transmission pricing. NERA prepared the attached paper to address concerns with the Norwegian and Swedish Electricity Markets and the proposed solutions are specific to that market.

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1. INTRODUCTION

The current systems of transmission pricing in Norway and Sweden have many attractive features. In particular, marginal costing of transmission losses and constraints in Norway provides good signals on the efficient use of the network. However, traders find it difficult to hedge the risks associated with zonal pricing of transmission constraints. Also, the incentives for the transmission companies to maintain and to invest in transmission are fairly undeveloped.

This report appraises the current systems of transmission pricing in Norway and Sweden and suggests areas in which they could be developed toward a theoretical paradigm for efficient transmission provision. Our appraisal takes place against a set of objectives for developing an efficient commercial framework for transmission. We discuss these objectives in section 2 before moving on to describe the current Norwegian and Swedish systems in Section 3. Section 4 develops a theoretical paradigm for efficient transmission pricing, which we then use to assess the existing systems (section 5) and to identify possible developments to the current system of pricing (section 6). Finally, in section 7 we summarise our conclusions. describes the economics underlying marginal cost pricing of losses and constraints.

2. ECONOMIC OBJECTIVES

In this paper, we will use several criteria to appraise the existing systems of transmission pricing in Norway and Sweden and in developing the paradigm of an efficient commercial framework. The basic economic objectives can normally be described in terms of different aspects of the transmission business and its role in the electric sector. The overriding objective is to minimise total costs to consumers for a given level of service. This will require the promotion of efficiency in:

- use of the network (i.e. efficient despatch);
- operation and maintenance of the network; and
- investment in expansions of the network.

Lying behind the overall goal of efficiency are two subsidiary goals:

- risk - the system of transmission pricing should allow traders to manage their risks efficiently; and
- equity - the system should be "fair" and equitable to all users.

These goals all deserve further consideration.

2.1. Efficiency

Efficiency goals can be achieved in many different ways, but the main choice is between central co-ordination (via monopoly ownership and/or Government control or regulation) and decentralised decisions (co-ordinated via a market). Central co-ordination may appear to be directed at the goal of efficiency, but often encounters a number of constraints:

1) there is a limit to the information that a central process can acquire from market participants;
2) central "optimisation" processes are often imperfect; and
3) central co-ordination backed by monopolies is subject to "capture" by certain participants with individual objectives.

For these reasons, central co-ordination often fails to deliver the benefits promised by its advocates. On the other hand, the efficiency of a market outcome is also subject to real constraints:

1) if participants do not possess good information about cost conditions and opportunities;
2) if economies of scale persist above the size of a typical project; and
3) if any single participant, or group of participants, has power over the market price.

In practice, therefore, the choice of markets versus central co-ordination depends upon the relative severity of the problems caused by each list of constraints.

2.2. Risk

The focus on risk management is important since it affects the cost of capital for the transmission company and the other market participants. Without the ability to manage risk, traders' cash-flows will be variable and this will increase the costs of financing their activities.[1] Certain combinations of investment may also prove difficult to finance, even if efficient. Generally, it is thought that consumers are better able to bear risk than companies within the electric sector (because consumers have a more diversified portfolio of risks - i.e. they do not just produce, transmit or consume electricity). Normally, therefore, costs to consumers are minimised by passing risks forward to consumers. However, there are two exceptions to this rule:

- when the *transactions costs* involved in hedging risks offset the benefits of risk management; and
- when total costs are minimised by imposing the risk associated with poor performance on producers, so that they have an incentive to perform efficiently.

An efficient commercial framework for electricity transmission must therefore achieve a balance between the allocation of risk (and hence the level of financing costs) and the incentives provided to sector participants to minimise other costs.

The regulatory framework governing transmission can also be a source of risk; the risk that regulators will not allow the transmission provider to recover sunk investment costs affects the cost of capital markedly. For this reason, it is important that transmission providers are able to recover their sunk costs according to a stable set of regulatory principles.

The method of allocating sunk costs to users of the transmission system can also affect the pattern of risk (and hence costs) in the sector. In particular, distribution companies as monopolistic network operators are likely to have more secure future cash-flows than generating companies. As a result, the most secure (and therefore the cheapest) method for a transmission company to recover its sunk costs might be through charges to distribution companies, rather than to other, less creditworthy users operating in competitive sectors.

[1] The extra costs derive both from an increase in the cost of capital and from the need for more active management of cash flows through financial instruments.

2.3. Equity

In the following, considerations of *equity* also play a role. Equity concerns arise for example, if existing users of the transmission system have to bear a share of the costs of upgrades required by new users and vice versa if new users have to pay a different price from existing users.

A "fair" method of charging should not discriminate *unduly* against or in favour of individual users of a transmission system. In practice, the identification of undue discrimination is difficult, since all issues surrounding the distribution of income are a matter for government policy. However, an economic approach to discrimination usually builds upon the concept that prices should be related to marginal costs. The range of possible definitions of marginal costs (in a competitive setting) then provides the acceptable bounds of discrimination:

- the price charged to a customer should not fall below the incremental cost of serving that customer; and
- the price charged to a customer should not rise above that customer's "stand-alone" cost, i.e. the cost that the customer would incur to provide his own service.

Although these rules are intended to answer questions about equity, they are also closely linked to the objective of efficiency; in electricity networks, a failure to charge new users the incremental cost of serving them means, first, that existing users are effectively cross-subsidising new entry but, second, that users may make inefficient decisions about the location of generation and demand. Some regulatory systems add a further criterion:

- that all customers with equivalent patterns of demand (or usage) should pay the same price.

Whilst there is nothing inherently wrong with this criterion in economic terms, it is debatable what is meant by "equivalent patterns of demand". Two users located in adjacent locations and with the same pattern of consumption may nevertheless impose quite different costs on the network, if one arrives some years after the others. It is common (e.g. in the UK) to find regulators who respond to such problems by encouraging utilities to charge both new and existing customers a "marginal-cost-related tariff". However, in practice, there is a limit to the extent to which the first customer will accept a price rise because the later customer imposes additional costs. Regulators therefore often step in to "moderate" price rises proposed by network utilities for some regions.[2] Such tariffs are therefore subject to additional constraints and rarely mimic marginal or incremental costs in any meaningful way.

[2] See OFFER's frequent interventions in the design of tariffs for the National Grid Company.

We regard such policies as inconsistent with many of the efficiency-related objectives and questionable in terms of equity. For this reason, we will focus upon the equity objective by reference to the "acceptable bounds of discrimination" discussed above.

3. THE CURRENT SYSTEM OF TRANSMISSION PRICING

3.1. Nord Pool

The Nordic Electricity Exchange (Nord Pool) was implemented on 1 January 1996. Buyers and sellers of electricity trade in a weekly contract market and in a daily spot market concluded at the day-ahead stage. In the spot market, traders can submit offers to sell or bids to buy the physical electricity they expect to produce or consume (the weekly contracts being purely financial commitments). The spot price is set equal to the marginal offer to supply (or bid to buy) accepted by the Exchange.

Transmission constraints within Norway and between Norway and Sweden are handled by splitting the market into zones. Statnett (the network operator) defines the zones according to its information on the likely pattern of flows on the system. Zones are often defined on a weekly basis, but may be redefined at short notice, e.g. even between the day-ahead stage and delivery. This element of Statnett's activities is subject to regulation as a monopoly. Sweden is always one zone in this market and has a different method for dealing with network constraints within Sweden (see below).

3.2. Transmission Pricing and Balancing in Norway

3.2.1. Point-of-Connection Tariffs

In Norway, all transmission investments are subject to approval by a department of NVE. This department requests a five-year forecast of projects from all network companies and issues the necessary "concessions" which allow them to carry out the work. In the event of two companies proposing projects which overlap or conflict, NVE will decide which should be awarded the concession.

Network companies who carry out investment projects receive in return an allowance for the associated costs, on the next occasion when their revenue requirement is reviewed by NVE. (In the mean time, the upper and lower boundaries on each network company's revenue increases at one half the growth rate of its total energy deliveries.) The network companies recover their revenue requirements through point-of-connection tariffs.

Statnett charges a point-of-connection tariff to other networks and users connected to the national transmission system. The tariff consists of:

- "Connection Charges" and a "Power Charge" related to installed capacity or to maximum demand during system peak hours, in NOK/kW; and
- an "Energy Charge" related to the cost of marginal energy losses by season or time of day, and differentiated by the point-of-connection, in øre/kWh;

- a "Capacity Charge" (or "bottleneck fee"), in øre/kWh, levied on flows over transmission constraints between the zones, as discussed below.

These point-of-connection tariffs are paid in respect of gross generation and gross demand; as far as possible, NVE discourages network users from quoting figures for net generation capacity or net demand, because the transmission system must be built to accommodate gross inputs and gross outputs independently of one another. However, this provision is difficult to enforce within sites which contain both generation and consumption, or where generation capacity falls out of use.

Statnett is subject to regulation by NVE, which determines the upper and lower bound for Statnett's total revenues (the "revenue frame"). Any variation in receipts from one of the elements of Statnett's charges must be offset by an equal and opposite change in another element, in order to stay within the "revenue frame". In practice, this means that variations in Capacity Charges (bottleneck fees) are offset by adjustments to the kW charges.

3.2.2. The Balancing Market

Imbalances between trades in the daily spot market and the actual amounts produced or consumed by traders are settled in the imbalance or "regulerkraft" market. The price for regulerkraft is set as follows:

- if total gross demand exceeds total demand in the spot market, the price for regulerkraft is set equal to the highest accepted offer to supply; and
- if total gross demand is less than total demand in the spot market, the price for regulerkraft is set equal to the lowest accepted bid to buy.

Although the market in regulerkraft acts as the outlet- or provider-of last resort for electricity in Norway, a far greater volume is traded through the day-ahead market and the day-ahead spot price is more commonly used as the benchmark for contract prices. In practice, any systematic differences between the spot price and the price of regulerkraft is eliminated by the possibility of arbitrage between the two markets at the margin.

3.2.3. Bottleneck Fees

Nord Pool *effectively* calculates prices for each zone which reflect the marginal cost of meeting demand in that zone, given the constraints on the transmission system. However, the process is somewhat indirect. Nord Pool first establishes a "system price", which matches offers and bids assuming no transmission constraints. Statnett then announces the bottleneck fees which will be applied to all spot and regulerkraft transactions, by zone. The charging principles are:

- in (low-price) surplus zones, sales attract a charge, whilst purchases receive a rebate;

- in (high-price) deficit areas, sales receive a rebate, whilst purchases attract a charge.

The net effect is to apply a different net price in each zone, to all spot and regulerkraft trades within that zone. As far as traders are concerned, therefore, this system is financially equivalent to using zonal prices for the spot market and for regulerkraft.

3.3. Transmission Pricing and Balancing in the Swedish Zone

3.3.1. Point-of-connection tariffs

Svenska Kraftnät charges a point-of-connection tariff to other networks and users connected to the national transmission system. The tariff consists of:

- an annual power fee (per MW); and
- an energy fee (per MWh).

The annual power fee is dependent on the latitude of the connected party. This is because the prevailing power flow on the network is from the north to the south of Sweden. Generators pay more in the North, where there is a surplus of generating capacity and less in the south where the load centres and export markets are located. Conversely consumers in the south pay more than consumers in the North.

The energy fee is calculated by applying a marginal loss factor to the connected parties' offtakes. Marginal loss coefficients also depend on latitude and have been calculated for high and low load, weekday and other times for each connection point. These coefficients can be positive or negative and range from +10 per cent to -6 per cent. Svenska Kraftnät currently charges for the marginal losses at the price it pays for replacement power. In future, it may decide to use the current spot price for energy.

Where new connections result in significant additional investment, Svenska Kraftnät charges the new user a one-off connection fee to cover part of the cost of the investment required.

The point-of-connection tariffs do not contain any charges or other signals regarding possible transmission constraints, other than via the indirect, long-term signals provided through the annual power fees and one-off connection charges. Svenska Kraftnät deals with constraints separately via the Swedish market's balancing regime as described in the following sections.

3.3.2. National Pool Markets

Svenska Kraftnät currently runs two national pool markets for each hourly trading period:

- a day-ahead one (i.e. Nord Pool); and
- a 2-hour ahead one.

The two-hour ahead market is a remnant of the trading regime in existence prior to Sweden's joining Nord Pool and it plays a role in balancing. Trading volumes in the 2-hour ahead market are low and the need for this market is currently under review. (Norway has no equivalent market.)

For output deviations after the 2-hour ahead market, pool members must submit offer prices (for increasing net output) and bid prices (for decreasing net output). Offer prices must be greater than or equal to the 2-hour ahead market price and bid prices must not exceed the 2-hour ahead market price.

3.3.3. Dealing with Transmission Constraints

Sweden has three to four zones defined by major transmission constraints. However, these zones do not appear in the national pool markets, nor do they directly affect transmission charges. When Svenska Kraftnät identifies a set of transmission constraints, its despatcher engages in "special regulation" i.e. the despatcher rebalances despatch to accommodate the constraint. To rebalance dispatch, Svenska Kraftnät:

- orders additional output from - or "constrains on" - generators in areas subject to an import constraint;
- backs down - or "constrains off" - generators in areas subject to an export constraint.

The plants subject to special regulation are paid their offer price for extra output when they are constrained on, and they receive their bid price for reducing output when constrained off. (The latter payment is equivalent to "compensating" constrained-off generators for their lost profit.) The net cost of undertaking these trades is charged to Svenska Kraftnät. Svenska Kraftnät recovers these costs via an allowance in its annual transmission charges. So far, this allowance has always been sufficient to cover these costs.

3.3.4. Balancing

After isolating the rebalancing trades required to deal with transmission constraints, the Swedish pool settles imbalances between actual quantities (generated and consumed) and the quantities already traded in the pool's advance markets. The prices used to settle these imbalances are:

- highest offer price paid for "regulating up" (which we will call System Marginal Price Plus, or SMP+);
- lowest bid price received for "regulating down" (which we will call SMP-);
- and the market price from the 2-hour-ahead market (the "spot price").

The price paid to or by pool members for their imbalances depends on whether output deviations were ordered by the despatcher. For instructed imbalances:

- when the system is "regulating up", traders get paid the highest offer price accepted for additional net output (SMP+); and
- when the system is "regulating down" the pool charges the lowest bid price accepted for reducing net output (SMP-).

Occasionally, Svenska Kraftnät regulates up and down in the same hour, in which case the Pool pays different prices to different parties, according to whether they were asked to regulate up or down in that hour.

To settle involuntary (i.e. undespatched) imbalances, Svenska Kraftnät nominates each hour as "regulating up", "regulating down" or "neither". Traders then pay (or are paid) the following prices for their involuntary imbalances according to whether they are "helping" the system or not:

Table 3.1

The Price for Involuntary Imbalances

	Regulating up	**Regulating down**	**Neither**
Positive imbalance	Spot price	SMP-	Spot price
Negative Imbalance	SMP+	Spot price	Spot price

3.4. Initial Assessment of the Current Systems

The current systems of pricing in Norway and Sweden have many attractive features. In particular, the system of zonal spot prices and locational loss factors is likely to give prices which closely approximate the local marginal cost of meeting demand (especially in Norway). However, the current systems have several potential shortcomings. We present an initial assessment of these potential problems in the following sub-sections.

3.4.1. Short-Run Energy Pricing in Sweden

The system of pricing constraints within Sweden results in local electricity prices which may differ from the local marginal value of electricity. This will have some effect on short-run efficiency.

For generators, these effects are limited, since they are allowed to quote offer prices which reflect the local value of electricity. We discuss below the scope for inefficient despatch. More

importantly, the absence of accurate signals for consumers about local marginal costs will distort usage of the transmission system in the short-term. However, the welfare effects of these distortions are likely to be small.

3.4.2. Risk Hedging Between Zones

The main concern currently being voiced within the Nord Pool system is that traders cannot hedge the difference between zonal spot prices on trades within Norway and between Norway and Sweden. As we explain in later sections, generators in Sweden may also face some risk from variation in their payments for rebalancing to meet transmission constraints. Traders are presently unable to hedge these risks. This is likely to have the following effects:

- increased financing costs which raise costs in the sector as a whole;
- distorted investment incentives (e.g. investment in local generation becomes more attractive than investment in transmission to bring power from a remote generation facility).

We explore the nature of this risk and its possible effects in sections 4 and 5 respectively.

3.4.3. Muted Incentives For Transmission Maintenance And Investment

In Norway, Statnett bears no financial responsibility for the cost of constraints at the margin, which are charged to users via the bottleneck fees. (Losses are handled via a separate charge, but Statnett expects to recover all costs over the course of several years.) Users of the system are allowed to propose investments in the network, but projects are subject to final approval by NVE. Users have few, if any, ways to influence Statnett's decisions over maintenance of the system.

In Sweden, Svenska Kraftnät bears any short-term additions to the costs of generating due to transmission constraints (including the cost of losses). Svenska Kraftnät therefore bears the costs of failing to maintain or to invest in the transmission system and can increase profits by choosing the optimal level of maintenance and investment. However, any incentives facing Svenska Kraftnät are purely short-term; in the long-run, Svenska Kraftnät would expect to receive a revenue allowance which passes through the cost of any investments or increases in losses. The efficiency of investment is not therefore assured by this mechanism alone.

In both cases, the lack of alignment between (1) responsibility for transmission investment and (2) responsibility for the costs of transmission (including the cost of losses and constraints) is bound to affect the efficiency of decisions about maintenance and investment in the transmission system. Of course, both Statnett and Svenska Kraftnät are publicly-owned companies with limited profit incentives, as are many regional network companies and other system users in both countries. All publicly-owned companies are formally committed to the pursuit of efficiency objectives. However, the lack of a private financing constraint, combined

with de facto monopolies, means that the efficiency of investment and maintenance by these companies is always open to question. Furthermore, the effect of incentives relating to profitability, or the lack of them, must therefore always be discussed with caution.

3.4.4. Incremental Users Do Not Pay Incremental Investment Costs

New users of the transmission system pay only part of the cost of the investments caused by their connection.

In Norway, the flat rate point-of-connection tariffs and the common bottleneck fees are unlikely to signal the incremental costs of connecting individual users; even the bottleneck fees will understate incremental costs, *after* a required investment has been carried out. Poor location decisions result in inefficiency, as new connections increase congestion and losses in the short-term and require unnecessary transmission investment in the long-term. Existing users may also consider it unfair that they are required to bear even part of the incremental investment costs required to meet the needs of new users.

This may be less of a problem in Sweden, since users bear at least part of the cost of the incremental investment and the point-of-connection tariffs are differentiated by location. However, the system of rebalancing to deal with transmission constraints in Sweden is very similar to the system operating in England and Wales. This system has faced some difficulties during a period of high investment in new generation capacity.

The National Grid Company's regionally-differentiated annual tariffs are partly offset by the compensation payments to generators who are constrained off. Furthermore, OFFER has resisted attempts by the National Grid Company to widen tariff differentials between regions as much as is required on economic grounds. The resulting compression of regional differentials has caused investment in new generation to concentrate in areas where the transmission system is already congested. This creates a need for additional and unnecessary investment in transmission. The regulator (OFFER) and the Pool are currently examining ways to unbundle transmission prices in ways which reflect local marginal costs more closely. OFFER is also reviewing the need to pay "compensation" to generators which are constrained-off the transmission system.

Svenska Kraftnät also pays "compensation" to generators which are constrained off. Although Svenska Kraftnät's policy of location-specific transmission tariffs and "deep" connection charges attempts to correct this possible bias, the scope for transmission prices to reflect incremental costs is limited. The net result may still be unnecessary investment in additional transmission facilities, although the level of investment in new generation capacity is currently not so high in Sweden as in England and Wales.

4. AN EFFICIENT COMMERCIAL FRAMEWORK

The following description of an efficient commercial framework is derived from the current academic literature on transmission pricing, which has been very influential in shaping discussions in the proposed restructuring of the Californian electricity industry. We present it here as a paradigm of an efficient system of transmission pricing which meets the key objectives set out in section 2 above. In section 5, below we move on to consider how this paradigm could be applied in Norway and Sweden.

The framework described below has the following key elements:

1) **Nodal spot prices:** spot prices for electricity for each trading period (e.g. hour) for each point or "node" on the system, calculated using an optimal power flow model or similar formula to estimate short-run marginal costs;
2) **A contract network of transmission rights:** a set of *financial* contracts ("Transmission Congestion Contracts") sold by the transmission company to system users, which allow users to hedge against "basis risk", i.e. against variation in the *difference* between the spot prices at two defined nodes;
3) **Incremental costing for new transmission rights:** a process whereby users commission the building of new transmission capacity, pay the incremental cost, and receive in return Transmission Congestion Contracts for all new capacity created by their investment.

The following sections explain in more detail what these concepts mean, and how they ensure efficiency.

4.1. Nodal Spot Pricing

4.1.1. The Concept of Nodal Spot Pricing

The concept of nodal spot prices for electricity emerges naturally out of the creation of multiple wholesale electricity markets. A competitive market in one area will arrive at a different price from a competitive market in another area, as long as transmission from one market to the other incurs some transmission losses, or the transmission capacity between them is constrained. If energy can be transmitted without losses and without encountering any constraints, power flow from the low price market to the high price market will increase, until prices are equalised; in effect, the two markets then become a single market with a single price.

However, as long as there are transmission losses or constraints, different spot prices can co-exist in different areas. The difference between these two market prices effectively defines the short-run marginal cost of transmission.

During the 1970s and 1980s, a team at the Massachusetts Institute of Technology headed by Fred Schweppe worked on a computer program to generalise this observation. By applying mathematical modelling techniques to the laws of (1) economics and (2) power flows over electricity networks, the team was able to develop a dynamic program that calculated spot prices for every node on a network, using the sort of information normally available for despatch purposes.[3]

explains the basic economics underlying the cost of constraints and losses for a simple, two-node system, before discussing how this analysis can be generalised to a system with many different market.

4.1.2. Local Spot Prices or "Bottleneck Fees"?

Nodal spot pricing recognises that the marginal cost of electricity is different at each location on the transmission system. On grounds of efficiency, users should see this marginal cost in the price that they pay for their energy. In practice, a system of nodal pricing can be implemented in several different ways:

- by defining a price at each node and paying a spot price for deliveries to that node and charging a spot price for offtakes from that node; or
- by defining the spot price at a central node and charging a transmission charge for taking power to and from that node (where the charge at any node is equal to the difference between the marginal cost at the user's local node and the marginal cost at the central node);
- by defining several zones with fixed transmission tariffs to get to a zonal "hub" and with variable bottleneck charges for transmission between hubs.

In practice, whichever system is finally adopted, the intention is broadly the same; users pay (get paid) the local marginal cost of their consumption (generation).

4.2. Contract Networks of Transmission Rights

Electricity traders typically buy and sell energy under contract at particular locations. They only pay spot prices for differences between their contracted deliveries and their actual deliveries. Contracts allow traders to hedge the risk associated with spot price variations in one location. However, when the buyer and seller are in different locations, and face different local spot prices, they must also pay a spot transmission fee - equal to the difference between their local spot prices - to deliver their power. Traders therefore bear the risk of variations in the difference between the two local spot prices. (This form of risk is often known as "basis risk".)

[3] See, for example, Bohn, R.E., Caramanis, M.C. and Schweppe, F.C. (1984) Optimal Pricing in Electrical Networks over Space and Time, *Rand Journal of Economics*, Vol. 13, No. 3.

As the examples in section 4.2.1 below will demonstrate, traders can allocate this risk between themselves by altering the location of their contracted trade. However, one or both of the traders must still bear this risk. Section 4.2.2 introduces the notion of a "transmission congestion contract" or "TCC" which allows traders to hedge locational price differences. The concepts outlined below are similar to those in any other hedging contract; the only real innovation is that the hedge now applies to a *difference* or "spread" between two prices, rather than to a single price. In other words, a TCC is a "derivative" of financial hedges against individual electricity spot prices.

4.2.1. Locational Price Difference Risk

An example may clarify the nature of the risks implied by nodal spot pricing. Consider a generator located at a node where the spot price is always $20/MWh, and a buyer located at a node where the price is either $20/MWh or $30/MWh. The traders can sign two different types of contract:

- sale at the generator's node at $20/MWh; or
- sale at the buyer's node at $25/MWh (=average of $20/MWh and $30/MWh).

The outcomes are shown in Table 4.1 below. If the point of sale is the generator's node, the buyer takes the risk that his local spot price will turn out to be either $20/MWh or $30/MWh. In the first case, the buyer pays just the contract price of $20/MWh. In the second case, the contract will incur a bottleneck charge (of $10/MWh) making the total cost $30/MWh. Since each case happens about 50 per cent of the time, the expected cost is $25/MWh (which is the average of $20/MWh and $30/MWh). Meanwhile, the generator earns $20/MWh in both cases.

If the point of sale is the buyer's node, the generator is exposed to a similar risk. Whenever the buyer's nodal price is $20/MWh, the generator earns a profit of $5/MWh on the contract; but if the buyer's nodal spot price rises to $30/MWh, the generator loses $5/MWh. (See shaded boxes.)

Table 4.1: Basis Risk in a Nodal Pooling System

All figures in $/MWh

Location of Contract Sale	Nodal Spot Prices		Bottleneck Fee	Cost of generation	Contract Price	Generator's Net Profit	Buyer's Net Cost
	Generator's Node	Buyer's Node					
	(1)	(2)	(3)=(2)-(1)	(4)	(5)	(6)	(7)
Generator's Node						=(5)-(4)	=(5)+(3)
Case 1	20	20	0	20	20	0	[illegible]
Case 2	20	30	10	20	20	0	[illegible]
Buyer's Node						=(5)-(4)-(3)	=(5)
Case 1	20	20	0	20	25	[illegible]	25
Case 2	20	30	10	20	25	[illegible]	25

Hence, either the buyer is faced with the risk of variation in costs or the generator faces variable profits, due to the varying difference between two spot prices. To hedge against this risk, traders need to find someone whose profits also depend on the same risk, but inversely to the risk faced by traders. The solution is to assign this role to an institution or agent which receives the profits earned from transporting energy from low-price to high-price zones - in short, the provider of the necessary transmission capacity.

4.2.2. Transmission Congestion Contracts

The solution to this problem emerged from further work by US academics and consultants. They may also have drawn on the experience of the Pool in England and Wales, where financial contracts are used to hedge against variation in the (one and only) spot price. A major proponent of the system has been Professor Bill Hogan of Harvard University. He has written many pieces setting out how nodal spot prices should form the basis for transmission prices, and how the transmission provider should issue financial hedges to offset the risk.[4]

The system is being discussed at length in California and offers some insight into how problems associated with basis risk in Nord Pool might be addressed. In principle, the contract network system works like this:

1) an agency (usually referred to as "Poolco" or the "Market Operator") calculates spot prices for every node on the system at which power enters or exits from the network;

[4] See W.W. Hogan, *Contract Networks for Electric Power Transmission*, Journal of Regulatory Economics, Vol.4, No. 3, September 1992. See also W.W. Hogan, *Co-ordination for Competition in an Electricity Market: Response to FERC Docket No. RM94-20-000 of October 26, 1994*, John F. Kennedy School of Government, Harvard University, 2 March 1995.

2) the agency pays for all deliveries into the network at the spot price for the node where the power is received;
3) the agency charges for all deliveries out of the network at the spot price for the node where the power is delivered;
4) in the first instance, the agency keeps the net revenue associated with these spot transactions;[5]
5) the agency issues Transmission Congestion Contracts (TCCs) to network users (e.g. by auction), to cover all their forecast use of the system, e.g. forecast sales from A to B;
6) the agency keeps any proceeds from selling TCCs;
7) under the terms of each TCC, the agency pays the holder a rebate equal to the difference between spot prices at the points linked by the TCC (i.e. A and B).

In our nodal pricing example above, the buyer or the seller (depending on the type of contract) would approach the agency ("Market Operator") for a TCC for transmission from the generator's zone to the buyer's zone.[6] Having bought the TCC, they would be entitled to receive a rebate from the grid company every time the spot price in the buyer's zone differed from the spot price in the generator's zone. Half the time, there would be no difference and no rebate would be payable; the other half of the time, the buyer's spot price would rise to $30/MWh and the grid company would pay a rebate of $10/MWh (=£30/MWh - $20/MWh). The rebate would therefore offset exactly the payment of any bottleneck charge (of $0/MWh or $10/MWh) for the actual flow from A to B.

Table 4.2: Risk Sharing by Transmission Congestion Contract

Row	Item	Unit	Case 1	Case 2
(1)	Flow from A to B	MWh	1	1
(2)	Spot Price at A	$/MWh	20	20
(3)	Spot Price at B	$/MWh	20	30
(4)	Bottleneck Charge	$/MWh	0	-10
(5)	Rebate Under TCC	$/MWh	0	10
(6)	Generation Cost	$/MWh	-20	-20
(7)	Contract Revenue	$/MWh	25	25
(8)	Charge for TCC	$/MWh	-5	-5
(9)	Net Profit	$/MWh	0	0

[5] There is usually a surplus derived from receiving power at low-price nodes and delivering it at high-price nodes.

[6] In Norway, the boundaries *between* "zones" are defined by the major constraints. Effectively, spot prices at nodes *within* a zone differ only by the amount of transmission losses. In considering price differences between zones, we are therefore effectively ignoring losses. Losses would become relevant if we discussed TCCs for transmission from the generator's transformer to the buyer's transformer.

Table 4.2 shows the effect of the TCC on the net profit of the generator (assuming that the generator is responsible for the bottleneck charge because the contract sale is located in the buyer's zone). Of course, given that there is a 50 per cent chance of the rebate being paid, the expected value of the contract is $5/MWh, which is the amount the agency would be able to demand for the TCC. By signing the contract, the network user fixes the cost of transmission at $5/MWh, regardless of the basis risk. In both cases, net profit is the same (i.e. zero).

4.2.3. Physical or Financial Contracts?

One of the reasons why California has been slow to take up the proposal to use TCCs is the desire expressed by many participants for "physical" transmission contracts, which confer a right to send power over the network, rather than "financial" contracts (TCCs), which merely offer a form of financial compensation for constraints. In fact, given the laws of power flow, even a physical transmission contract cannot give any trader an inalienable right to send his or her own power from A to B. The differences between the two types of contract are therefore matters of procedure in despatch and settlement, and are not related to their real or financial effects.

- Efficiency of Despatch:
  - Under the Hogan proposal, optimal despatch is arranged by a central despatcher, using a system of offer prices.
  - With physical contracts, the primary holders of "firm capacity" first build up a schedule of intended flows; if they do not require all their firm capacity for own use, they can sell the spare capacity to "interruptible" users; if any spare capacity still remains unsold, firm capacity holders may turn it over to the system operator for "economy interchanges" (i.e. optimal central despatch of other generation), in return for a share of the proceeds.
  - The relative efficiency of the resulting despatch depends on the advantages of central co-ordination versus the merits of bilateral market transactions (bolstered by the despatcher's last-minute ability to optimise despatch via "economy interchanges"). In practice, even after allowing for transactions costs, the differences are likely to be small.
- Method of Settlement:
  - As with all financial contracts, the TCC issuer's obligation is settled in cash, by providing a rebate equal to the short-run cost (or value) of transmission from A to B.
  - In a physical contract, the issuer credits the holder with the physical movement of electricity from A to B, i.e. from a low-price node to a high-price node.
  - The value of the credit for physical movement of power is of course exactly the same as the short-run value of transmission.

In California, arguments about the type of contract focused on the relative efficiency of generation under central despatch versus the inefficiencies due to the imposition of a "monopoly" despatch service. Both systems are intended to achieve an efficient despatch by responding to short-term price signals, either trader's offer prices (for financial contracts) or the prices of interruptible use and economy interchange (for physical contracts). Some opponents of TCCs also objected to the obligation for network users to join the Pool, but offered no other credible method of charging for imbalances.

In the end, the Californian Public Utilities Commission seems to have accepted that both forms of scheduling and despatch procedure can co-exist, although the implications for transmission contracts (i.e. whether both forms of contract can co-exist) do not seem to have been finalised. Since financial contracts can in principle be made to do anything that a physical contract can do, it is likely that "physical" contracts will in fact be "financial" contracts with additional conditions relating to the pattern of output and scheduled flows.

4.3. Implications for Short-Run Efficiency (in Use and Operations)

The efficiency with which the transmission system is used depends upon the optimality of despatch. Any form of transmission contract may affect despatch, depending upon how it is written.[7] However, the TCC system assumes central despatch, market-based spot pricing, and transmission contracts with quantities fixed in advance. In these conditions, efficiency of use is more or less assured, subject only to a number of concerns common to all systems as discussed in section 4.3.1.

The second component of short-run efficiency is the incentive for the Transmission Provider[8] to operate the system efficiently. Short-run operations comprise the maintenance of transmission capacity and the co-ordination of despatch. Whilst maintenance incentives are relatively simple to analyse (see section 4.3.2), there remain some concerns and unsolved problems in the efficiency of despatch (as discussed below in section 4.3.3).

4.3.1. Efficiency in Use (Generation and Consumption)

The incentive for generators to generate depends on the spot price at the node to which they are connected (that being the price of any uncontracted output). In principle, the spot price provides an efficient market signal. As with all market price systems, however, the efficiency of despatch will be compromised if individual generators possess market power in any area

[7] For example, a physical contract will affect despatch if it is non-transferable, since it will bias the holders' decisions in favour of using own supplies. A physical contract may also allow holders to distort despatch by withholding supplies from low-price areas, in order to push up the price in the receiving zone. The efficiency of despatch depends first on the despatcher's ability to overcome these constraints and to rebalance the pattern of output, e.g. by using "spare" capacity for economy interchange.

[8] In many countries, the Transmission Provider, who provides access to users, will also own and operate the system directly. However, in some systems (e.g. Norway, California), the agency which provides and controls access is different from the body or bodies which own, or even maintain the assets. We therefore usually distinguish between Transmission Providers and Transmission Owners.

bounded by constraints and can therefore affect the price they earn. In this paper, we assume that such problems of competition policy either do not arise or are dealt with in ways which do not greatly affect the choice of transmission pricing system.

Exactly the same considerations apply to the use of market price signals to ensure efficient patterns of consumption (over time and space).

4.3.2. Efficiency in Maintenance of Capacity

The incentive to maintain capacity depends upon the financial rewards and penalties for variation in the volume of available capacity. In a system where the revenue of the Transmission Provider is regulated without reference to actual capacity, or if the Transmission Provider is a non-profit organisation, the absence of any incentive is a problem. However, suppose that the Transmission Provider's total revenues rise and fall in line with net receipts from bottleneck charges and TCC rebates. Table 4.3: Marginal Incentives shows the effect of Transmission Congestion Contracts on marginal incentives to provide transmission capacity.

In the example in Table 4.3: Marginal Incentives, available capacity between two places varies between 40 and 220 MW. Over this range, bottleneck charges vary between $15/MWh (at 40 MW) and $0/MWh (above 190 MW). In Case 1 (columns 3 to 6), the Transmission Provider offers no TCCs. Its net surplus before operating costs is simply the product of available capacity and bottleneck charges.

Suppose that the cost of providing capacity (in terms of extra maintenance expenditure) is $4/MWh. Each 10 MW of additional capacity costs $40. The Transmission Provider maximises profits by offering 80 MW of capacity (column 1), since offering 10 MW increments of capacity above that level brings in marginal revenue less than $40 (column 6).

Table 4.3: Marginal Incentives

Basic Data		Case 1: No TCCs				Case 2: TCC Volume = 200 MW			
Actual Capacity MW (1)	Bottleneck Charge $/MWh (2)	Receipts $ (3)	TCC Rebate $ (4)	Net Surplus $ (5)	Marginal Revenue $ (6)	Receipts $ (7)	TCC Rebate $ (8)	Net Surplus $ (9)	Marginal Revenue $ (10)
40	15.00	600	0	600		600	3000	-2400	
50	14.00	700	0	700	100	700	2800	-2100	300
60	13.00	780	0	780	80	780	2600	-1820	280
70	12.00	840	0	840	60	840	2400	-1560	260
80	11.00	880	0	880	40	880	2200	-1320	240
90	10.00	900	0	900	20	900	2000	-1100	220
100	9.00	900	0	900	0	900	1800	-900	200
110	8.00	880	0	880	-20	880	1600	-720	180
120	7.00	840	0	840	-40	840	1400	-560	160
130	6.00	780	0	780	-60	780	1200	-420	140
140	5.00	700	0	700	-80	700	1000	-300	120
150	4.00	600	0	600	-100	600	800	-200	100
160	3.00	480	0	480	-120	480	600	-120	80
170	2.00	340	0	340	-140	340	400	-60	60
180	1.00	180	0	180	-160	180	200	-20	40
190	0.00	0	0	0	-180	0	0	0	20
200	0.00	0	0	0	0	0	0	0	0
210	0.00	0	0	0	0	0	0	0	0
220	0.00	0	0	0	0	0	0	0	0

In Case 2 (columns 7 to 10), the Transmission Provider has sold 200 MW of TCCs. Column 8 shows the rebates that the Transmission Provider now has to pay to users. Applying the same data for bottleneck charges (columns 1 and 2), the profit maximising level of capacity rises to 180 MW, above which marginal revenues per 10 MW fall below $40 again (column 10).

Hence, the effect of offering 200 MW of TCCs is to increase the profit-maximising output of the Transmission Provider from 80 MW to 180 MW.

This analysis does not tell us how many TCCs the Transmission Provider should offer, but in practice the scope for error is likely to be small. As long as the volume of TCCs reflects the level of capacity that users expect to be available, the incentive for the Transmission Provider to curtail capacity below this level is very limited. Professor Hogan proposes only that the allocation should be "feasible", i.e. consistent with a *possible* pattern of despatch within any given grid configuration. This condition guarantees that bottleneck charges will always exceed TCC rebates in aggregate, i.e. it guarantees the short-run "revenue adequacy" of the Transmission Provider. Any voluntary deviations from the feasible despatch are assumed to be

welfare enhancing. The definition of feasible patterns of despatch is a topic to which we return below, in the context of investment incentives.

4.3.3. Efficiency of Central Despatch

As far as central despatch is concerned, there remains a residual concern that the despatcher might try to bias despatch in order to maximise the net surplus (bottleneck charges minus TCC rebates), rather than to minimise generation costs. For example, if the transmission company has *less* capacity than it has sold by TCCs, the despatcher might despatch higher price generators in low-cost zones, in order to *reduce* the difference between spot prices, and hence to *lower* net rebates. The ability of the despatcher to behave in this way depends on:

- the method for calculating spot prices (which may ignore out-of-merit generation);
- the degree of vigilance of those traders who are disadvantaged by such actions; and
- the possibility of making the despatcher independent of the Transmission Provider.

There is no easy solution to this problem, since few Transmission Providers are prepared to hand over despatch to another party. The difficulty of solving this problem goes a long way towards explaining why system users may be nervous of central despatch and financial contracts, and may want physical transmission rights and decentralised scheduling. In practice, one observes three different methods of dealing with the problem, sometimes in combination:

1) derive spot prices (and hence bottleneck charges) from a schedule created independently of actual despatch, e.g. by using an optimal power flow (despatch) model, and then make the Transmission Provider liable for (some or all of) the generation costs in excess of the cost of this schedule;[9] or
2) make the Transmission Provider's total profits independent of actual bottleneck charges;[10] or
3) make the Transmission Provider non-profit-making.[11]

The Swedish system has elements of 1 and 3 above; Svenska Kraftnät is responsible for the cost of rebalancing to meet transmission constraints and is a state-owned non-profit oriented Transmission Provider. In Norway, Statnett applies methods 2 and 3. Statnett's profits are independent of actual bottleneck charges, since any receipts from this source are netted off their transmission revenue requirement; furthermore, Statnett's profit incentives are muted by its public ownership status.

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[9] This is Professor Hogan's preferred method. Even the Unconstrained Schedule in the Electricity Pool for England and Wales could be said to perform a similar function. In Hogan's version, the Schedule would include constraints.

[10] In Norway, bottleneck charges are used to offset Statnett's other charges, as Statnett receives a fixed total income.

[11] This approach has been proposed in California.

Of course, removing profit incentives related to bottleneck charges tends to undermine the incentive for the Transmission Provider to ensure that capacity is made available. On the other hand, whilst the first method retains profit incentives for efficient performance by the Transmission Provider, it also divorces spot prices from actual conditions and may give signals which encourage inefficient generation or consumption. The best achievable outcome may therefore be to adopt whichever method seems most likely to reduce total costs overall in the conditions of the system concerned.

4.4. Implications for Long-Run Efficiency (in Investment)

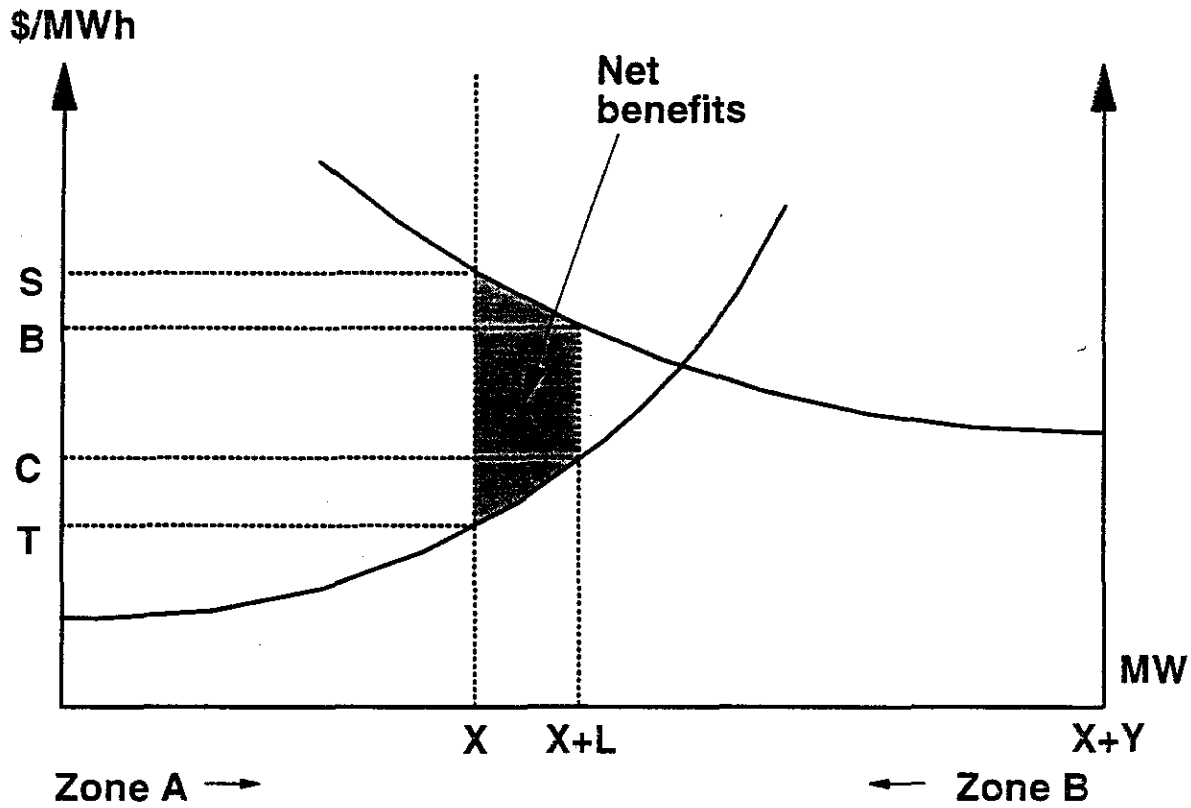
Although despatch has been the subject of some interest in California, the global debate of nodal spot pricing has focused more on its potential to drive efficient investment in transmission capacity. The debate is starting to clarify how investment might be organised.

4.4.1. Incentives for Expansion

Figure 4-1 summarises the incentives for building new transmission capacity. The line sloping upwards from left to right shows the generation costs in zone A and the corresponding line sloping upwards from right to left shows the generation costs in zone B. The total width of the horizontal axis is the total demand in both zones (i.e. X+Y).[12]

[12] See Appendix 1 for a derivation of this graph.

Figure 4-1: The Benefits of Trade Between Zones



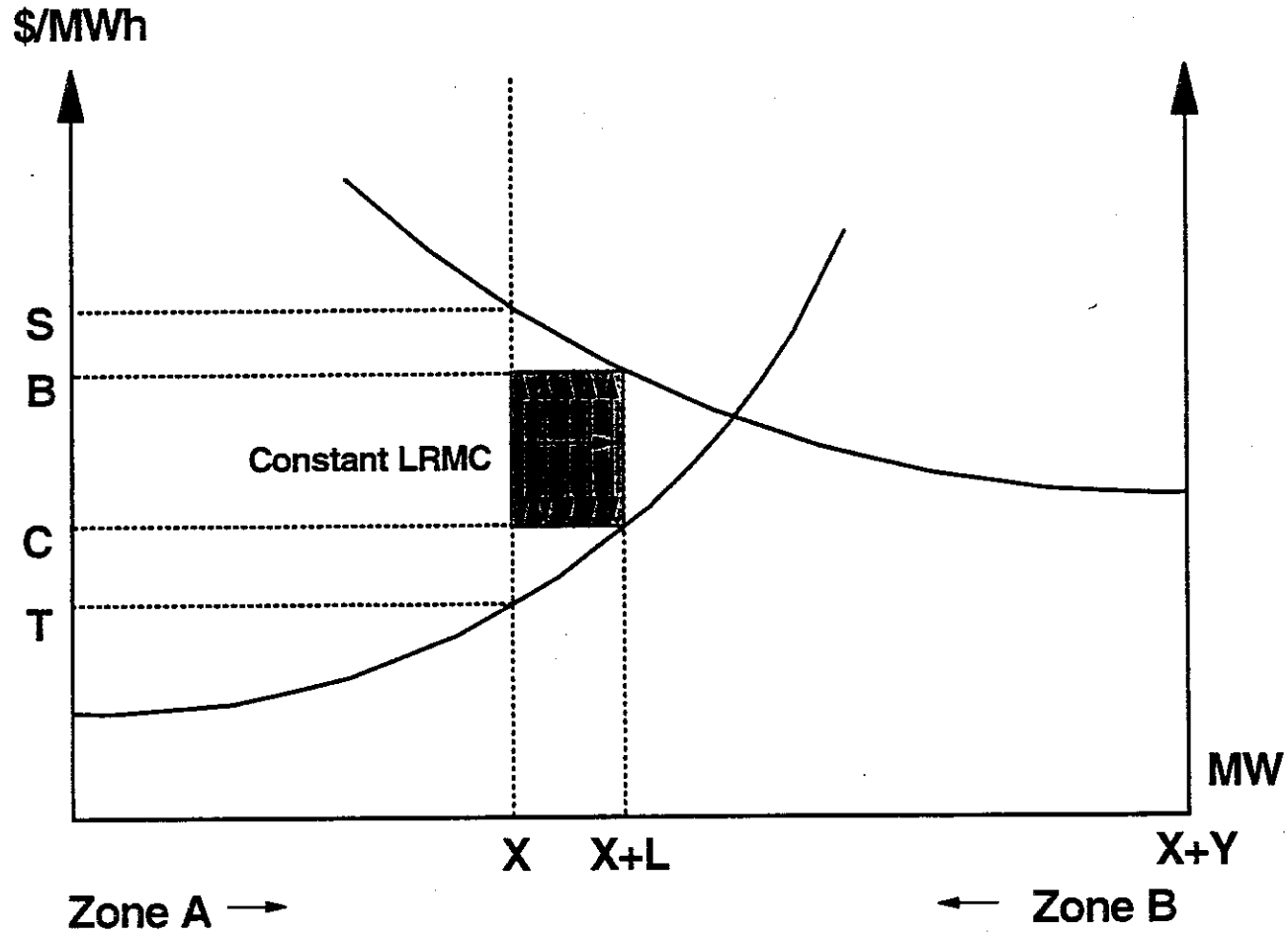
Given demand of X in zone A and demand of Y in zone B, there are potential gains from trade between the zones, because of the difference between their system marginal costs. Each unit of transmission capacity reduces generation costs, but to a declining degree. The first unit of transmission capacity saves an amount equal to ST, for instance. However, by the time capacity has expanded to L, the remaining gap between system marginal costs is only BC.

Whether the link should, or will, be built depends on whether the trading benefits are larger or smaller than the cost of building the link. The following two sections discuss two possible situations; one where there are no economies of scale in building the link and the other where these economies are present.

4.4.1.1. *No Economies of Scale (Constant Returns to Scale)*

If we presume that the incremental cost of transmission capacity is equal to BC for all units of capacity (no economies of scale), then it is economic to build only L units of capacity. This is shown in Figure 4-2 where additional construction continues (at a marginal cost of BC) until the marginal gains from trade equal BC. Further construction costs BC per unit of transmission capacity, but reduces generation costs by a lower amount.

Figure 4-2: No Economies of Scale in Construction



In these circumstances, anyone has an incentive to build the link, provided that they can capture the reward for doing so, in the shape of the bottleneck charges on power flow from zone A to zone B. Since a constraint persists, the bottleneck charge equals BC. The provider of the link earns this charge on a power flow equal to the volume of the link, i.e. L. The provider's revenues are therefore equal to BC.L, or the area of the grey rectangle. If there are no economies of scale, these revenues also equal the total cost of building the link.

Note that the link may be built by anyone who anticipates making sufficient revenues to cover costs, not just established traders in the market, or the transmission company. The beneficiaries include all generators in zone A, where the spot price rises for output X, and all consumers in zone B, where the spot price falls for consumption Y-L. However, these gains on trade within each zone are offset by equal and opposite increases in costs to consumers in zone A and falls in revenue to generators in zone B. As such, they merely represent transfers between members of society which do not justify any additional expenditure. Expenditure on

the link from zone A to zone B is justified only by the real cost savings attributable to inter-zonal trade, not by these transfers between traders within zones. The link can therefore be built by anyone who can capture the benefits in charges for using the link.

4.4.1.2. Economies of Scale

Unfortunately, this simple situation is complicated by the existence of economies of scale. Although the marginal increment to capacity may cost BC, setting up the link (e.g. arranging planning permission, buying the right-of-way and designing the towers) may impose additional costs which are unrelated to volume. Unit costs may also be higher for the initial units of capacity owing to economies of scale in production or design of transmission capacity (e.g. the need to provide one extra circuit to allow for N-1 contingencies, regardless of the total number of circuits). These initial costs increase the total cost of the link and affect the way it will be appraised.

Figure 4-3: Economies of Scale in Construction

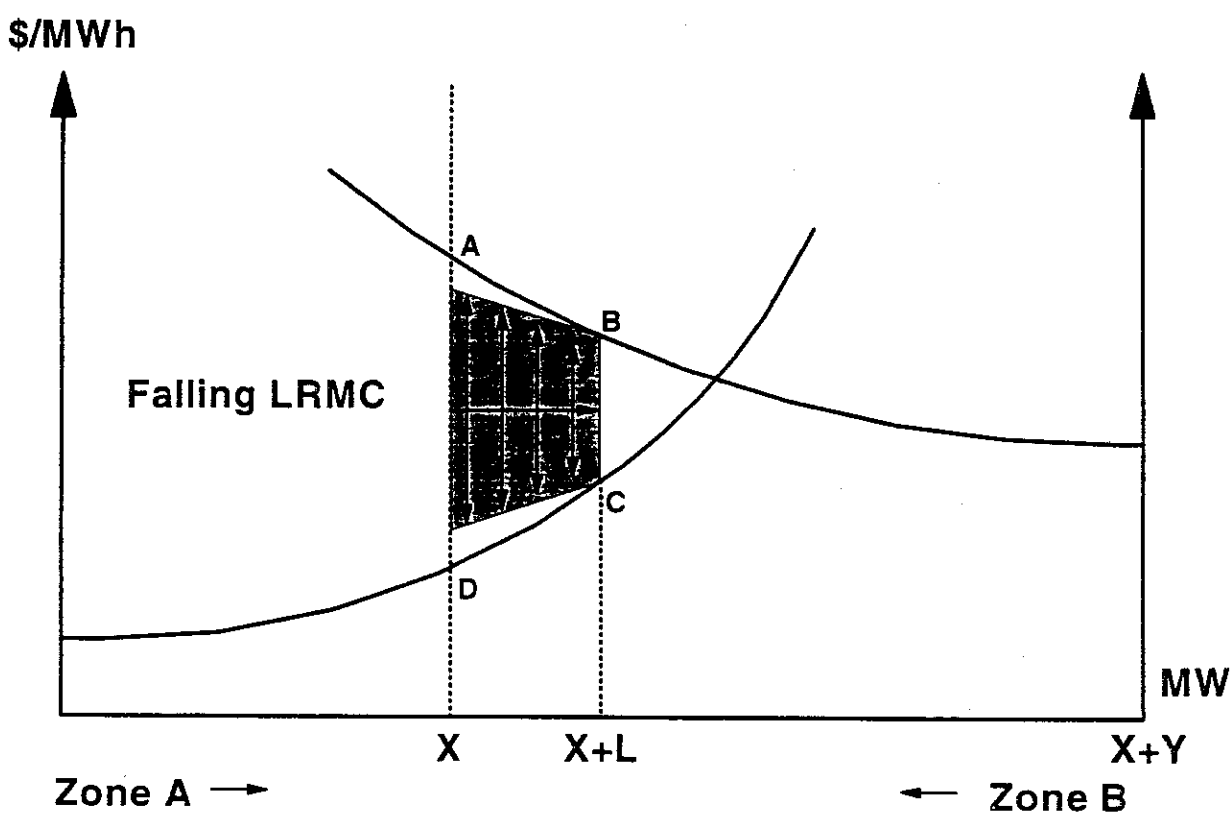


Figure 4-3 shows the economic appraisal of a link with economies of scale. The total benefit of the link is defined by the total net reduction in generation costs, i.e. the area ABCD. The shaded area shows the total cost of a link with economies of scale (as shown by the falling long-

run marginal cost of the link). As long as the total cost of the link is less than ABCD, it is efficient (as shown in the diagram). The optimal size of the link is still determined by the incremental cost of capacity, BC, since beyond this point no further net gains from trade are made. However, bottleneck charges earned at a rate BC would only generate (BC × L) and are no longer sufficient to recover the total cost of the link.

In these circumstances, it is necessary to find a *coalition of beneficiaries* who are willing (between them) to pay the full cost of the link, in return for the right to earn bottleneck charges and to benefit in other ways. For example, the coalition might well have to include a few generators in zone A and consumers in zone B, since they benefit from the price movements in each zone. Although the link's revenues from bottleneck charges will never pay off its full cost, investors with an interest in power markets benefit in other ways and are therefore prepared to finance the project.

This formation of coalitions presents a problem, however. Some coalitions may be willing to finance investments because they benefit both from the gains to trade (the area ABCD) and from transfers of welfare (from generators to consumers or vice versa) within zonal markets.[13] Including transfers in the benefits may lead to over-investment. The solution is to provide a forum (e.g. a law court or some other less formal administrative procedure) which allows those adversely affected to present a claim for compensation. Those who benefit merely from transfers can afford to compensate those who lose out from transfers. Only efficient projects provide a *net* benefit in addition to the transfers, which means that they create enough surplus to compensate all parties. This is the ultimate assurance that only efficient projects will overcome financial and legal hurdles.

Unfortunately, although there is some experience of this system in the United States, it usually relies on utilities to represent the interests of individual consumers. How the process would work in a fully competitive environment, where each consumer is responsible for his or her own costs of supply, has yet to be demonstrated. Ultimately, the transactions costs of forming a coalition and compensating affected parties may outweigh the energy cost savings derived from most investments in transmission. Imposing a retail franchise is one way to reduce transactions costs, since distribution companies can negotiate on behalf of their captive customers, but franchise monopolies impose distortions in other areas. It may be that few investments in transmission will be possible until consumers are prepared to sign long-term commercial contracts with suppliers; suppliers would then have an incentive to argue on behalf of those consumers with whom they have a contract.

Another possible route is to centralise decisions under a monopoly agency (which may or may not be the Transmission Provider) and to subject them to normal cost-benefit criteria. This

[13] The reason why transfers are a significant factor is that incremental investments in transmission are usually large enough to affect prices within zones. This is not the case, for example, with marginal trades in other commodities between different countries, which hardly affect the price in each country at all.

approach would, however, suffer from the usual problems of monopoly provision and it would not be clear how the costs of the new capacity created by the investment should be allocated to users in a way which encourages efficient decisions about the location of new connections and use of the expanded system.

4.4.2. Rewards for Investment

The analysis in section 4.4.1 above assumes that investors are able to capture the benefits of power flow over the link, by receiving bottleneck charges. One way to do this is to establish a separate company, to act as Transmission Provider for the capacity of the link as a separate facility. However, in an integrated network, such arrangements are unnecessary. Consideration of TCCs suggests a system which allows investors to contribute directly to the construction of capacity within an integrated system.

In general, discussions in California assumed that investors who paid for investments in the transmission system would receive TCCs equal to the capacity created by the investment. Such allocations of TCCs would have to be consistent with Hogan's "feasibility" rule, but would provide the basis for rewarding investors. Whenever the capacity created by an investor became congested, the Transmission Provider for the integrated system would impose a bottleneck charge, and the investor would be rewarded by receiving a rebate equal to the bottleneck charge for the capacity concerned. It was clear that this system of contracts would pass benefits back to investors, but there was some doubt as to whether it would encourage efficient investment in transmission, which most people viewed as a natural monopoly.

The answer arose out of discussions conducted in the Electricity Journal (in relation to the Californian proposals) of the "optimality" of nodal spot prices. In the April 1995 edition, Oren et al. produced an example in which power appeared to flow from a high-price node to a low-price node, contravening normal expectations.[14] They therefore disputed whether nodal spot prices should play any role in transmission pricing. Discussion continued in the August/September 1995 edition, but Bushnell and Stoft provided a reasoned response in the January/February 1996 edition.[15]

By analysing the example given by Oren et al., they found that some investments were, if not sub-optimal overall, then at least *destructive* of transmission capacity along *some* paths. They pointed out that the feasibility rule developed by Hogan had to take into account any changes in capacity, whether positive or negative. Hence, if any investment created capacity on one path (J to K), but destroyed it on another (M to N), the feasibility rule required an adjustment of TCC volumes on both routes. The investor could be rewarded with TCCs for the additional capacity on path J to K, but the feasibility rule required a reduction in TCCs applicable to path

[14] Schmuel S. Oren, Pablo T. Spiller, Praven Varaiya and Felix Wu, *Nodal Prices and Transmission Rights: A Critical Appraisal*, The Electricity Journal, Vol. 8, No. 3, April 1995.

[15] J. Bushnell and S. Stoft, *Grid Investment: Can a Market do the Job?*, The Electricity Journal, Vol. 9, No. 1, January/February 1996.

M to N. This could be achieved by making the investor accept the obligation to sell TCCs to the Transmission Provider on path M to N (instead of buying them from the Transmission Provider). This rule would ensure that investors only carry out efficient investments in transmission (or suffer the consequences).

4.4.3. Long-Term Contracts and Unavoidable Sunk Costs

The allocation of TCCs in relation to investment applies through time as well as space. If an investment creates transmission capacity that lasts for 20 years, the Hogan rule and the approach taken by Bushnell and Stoft suggest that the Transmission Provider should allocate TCCs for the total volume *and duration* of the capacity created and destroyed. This means that TCCs would be long-term contracts. For the sake of efficiency, they should also be transferable, to allow for others to take over use of the capacity, i.e. to reconfigure their trading arrangements and to acquire the associated hedging.

In this system, irreversible investment costs are not avoidable, since they are effectively paid by the beneficiaries at the time when they are incurred. The Transmission Provider might charge an annual fee for each TCC, e.g. to meet maintenance costs. However, since each annual fee would be specified in advance in a long-term TCC, and since the annual fee would be unrelated to usage, such fees would be unavoidable, except in the event that the holder goes bankrupt. The problem of "sunk cost recovery" is therefore assumed away, by instituting a system of customer contributions in advance and long-term commitments to pay.

In such a system, the risk of bankruptcy is non-negligible. Investors will need to borrow to finance investments in the grid, and their cost of capital will reflect their risk of bankruptcy, even for individual projects. More secure companies will be able to finance investments more cheaply. Similarly, the Transmission Provider may be reluctant to award long-term rights of uncertain value to non-creditworthy system users. This suggests that investments will be funded directly or indirectly by companies who have secure access to future revenues - in the electricity sector, this is more likely to mean distribution companies than generators.

4.4.4. Institutional Implications

The point of this discussion is to demonstrate the balance between decentralised investment decisions and central co-ordination. Nodal spot prices can provide incentives for efficient investment. However, even a decentralised system would need a central agency, the Transmission Provider, to calculate what capacity is created or destroyed by any investment and then to ensure that investors buy/sell the necessary portfolio of TCCs. This agency might be the transmission owner or operator, or it might be a co-ordinating council of some kind.[16]

[16] The Californian electricity industry is still reliant on Regional Transmission Associations (RTAs), working with the Western System Co-ordinating Council, to publicise transmission investment proposals and to provide a forum for affected parties to object and/or to negotiate compensation for any diminution in their rights. In a sense, therefore, RTAs already provide the basis for the co-ordinating role assumed by Bushnell and Stoft.

Hence, even nodal spot prices do not seem to have eliminated the need for central co-ordination entirely.

4.5. Summary of the Efficient Commercial Framework

The previous sections have set out at some length the economic elements which would constitute an efficient pricing regime for electricity transmission. These elements are:

1) nodal spot prices for all points of entry and exit;
2) long-term financial contracts for transmission (Transmission Congestion Contracts);
3) incremental costing of investments in additional transmission capacity.

Implementation of this system implies a number of new roles for existing (or new) institutions:

1) a Market Operator will calculate nodal spot prices;
2) a Transmission Provider will own and operate all grid investments, will receive the bottleneck charges implied by differences between nodal spot prices, and will issue TCCs for all capacity;
3) coalitions of beneficiaries will finance new grid investments, in return for new TCCs which match the transmission capacity created or destroyed by each investment.

There remain a number of complex technical and economic issues which have so far delayed the implementation of such a scheme. For example, it is not clear whether the despatcher should have the ability to influence nodal spot prices; nor is it completely clear whether the Transmission Provider will have an incentive to maintain the optimum level of transmission capacity. More importantly, it is necessary to be able to define transmission capacity in different conditions, and to reflect this estimate of actual capacity in the net volume of TCCs issued. TCCs may therefore be complex instruments and their capacities will only be defined by complex simulations. So far, therefore, it has proven difficult to argue that the need for regulation of transmission can be eliminated completely. These institutional issues will have to be resolved in the manner best suited to the country concerned.

5. ASSESSMENT OF THE CURRENT SYSTEMS

5.1. Norway

5.1.1. Spot Pricing

The system of spot pricing in Norway already closely approximates a system of nodal pricing; bottleneck and loss charges effectively realise prices at each node which differ by an amount which broadly reflects the cost of transmission losses and constraints. However, there are some small differences between hourly nodal pricing and the current system in Norway. These differences stem from the following factors:

- loss charges are updated infrequently and may therefore not exactly match the marginal cost of losses within any one hour;
- the zonal boundaries only apply to major constraints and are only defined for each day, which may lead to differences between the actual pattern of constraints in any one hour and that reflected in the zonal boundaries; and
- bottleneck fees are calculated from the prices offered or bid within each zone. Traders' estimates of costs or of the market price may fail to capture the effects of parallel flows on the transmission system, which means that the opportunity cost of electricity in any one location may differ from the marginal production cost at that location.

All of these factors mean that the price at any one location in Norway may at times differ from the nodal marginal value of electricity. This may create some inefficiency in the pattern of despatch. However, a producer's "marginal cost" of generation is defined by the opportunity cost or "shadow value" of water. This may obviate the need for a complex, centralised optimisation program to calculate the local marginal cost of electricity; instead generators can estimate the local market value in conjunction with their estimate of the marginal value of their water. Nodal values would then be implicit in the bids in any one zone, without the need to account explicitly for network interactions (including parallel flows) in a complex program. There are several good reasons for believing that the likely inefficiencies caused by using a zonal system which relies on users' estimates, rather than a model of the whole system, are likely to be small:

- in a predominantly hydro system, generator costs are relatively stable over the short- to medium-term, which means that the pattern of losses and constraints is likely to change less frequently than in a thermal system;
- in the relatively simple nature of the Norwegian and Swedish transmission system, the impact of failing to account for parallel flows may be rather small; and
- an optimal power flow model is constrained in its ability to capture data about the system and may produce prices which are no more accurate than users' own estimates.

In practice, therefore, there may be little material difference between the current system of zonal pricing in Norway and the use of a more complex, centralised programme to calculate nodal prices.

5.1.2. Hedging Bottleneck Fees

Traders in Nord Pool bear the cost of bottleneck fees on the net flows between zones of the exchange. These fees will vary as zonal boundaries and cost conditions within the zones change to reflect current conditions on the transmission system.

While traders already use contracts to hedge the risk associated with the market price at any one location, there is presently no way that they can all hedge the variation in bottleneck fees for the delivery of power by contract from one zone to another. Either the seller or the buyer under the contract must therefore take the risk that bottleneck charges rise to unexpectedly high levels.[17] (The allocation of this risk between traders depends upon the location of the contract trade - as discussed in section 4.2.1. above.) This risk makes traders' cashflows less predictable which may, in turn, increase their financing costs and costs in the sector more generally. (Unhedged risk may also be a source of general unease and complaints about the system.)

One other possible effect of this inability to hedge bottleneck fees, is that it becomes more attractive to site generation close to load, rather than to face the risk of variable bottleneck fees. This might lead to inefficient decisions in favour of local generation investments rather than investments in remote generation plus the transmission needed to bring power to the consumer.

5.1.3. Muted Maintenance and Investment Incentives

Statnett is not directly responsible for the cost of congestion and losses on its transmission system. Profitability therefore provides little incentive for Statnett to manage congestion and to invest in transmission facilities which might reduce losses and congestion. Moreover, while users bear the cost of losses and constraints at the margin, they can only affect transmission indirectly through the regulatory process. The result is likely to be a inefficient level of investment in new transmission facilities, which increases costs in the sector as a whole. Aligning the risk of additional congestion and losses more closely with the responsibility for investing in transmission might increase efficiency in transmission investment in Norway.

[17] *Some* generators and consumers can achieve a perfect hedge, by combining hedges for the two different spot prices, to produce the derivative hedge against basis risk. However, this is not possible for *all* traders, unless the recipient of bottleneck fees enters the market to sell TCCs.

5.1.4. Incremental Users Do Not Pay Incremental Cost

In Norway, users see the marginal congestion cost at their location. However, all users bear the cost of transmission investments in Norway via increases to transmission charges. Such investments reduce the costs of congestion. Incremental users therefore only see a share of the cost that they impose by connecting to the system. This can have two main effects:

- incremental users make poor locational decisions, thereby increasing costs in the sector as a whole; and
- existing users bear part of the cost of new investments and/or the increased congestion or losses caused by a new connection, which may violate the equity objective (depending on whether one thinks it is more equitable for incremental costs to be assigned to those who cause them, or shared with those who do not).

The magnitude of the potential efficiency gains will depend on the level of transmission investment, and hence on the growth rates of generation capacity and consumption.

5.2. Sweden

5.2.1. Spot Pricing

Unlike Norway, which is divided into zones and has locational loss charges, local prices in Sweden only differ by the cost of losses. The net cost of transmission constraints within Sweden is added to other transmission costs and recovered through the annual transmission tariff. The system for dealing with transmission constraints provides reasonable cost signals to generators, despite the absence of a zonal spot price.

Output from generators constrained on or off the system is settled at their offer or bid price. Generators knowing the likely pattern of constraints on the system can therefore adjust their prices to reflect the local marginal value of their output. These "local prices" should be very similar to those achieved in a more formal system of nodal pricing. However, there may be some lost efficiency in despatch if generators mis-estimate the local marginal value of electricity in setting their prices or if the local marginal value changes a lot during a period when generators may only offer one price.

On the other hand, consumers and retailers buying from the Swedish pool do not see the short-term marginal cost of their consumption. To the extent that buyers respond to cost signals - by their short-term consumption and longer-term location decisions - this lack of short-term marginal cost signals will reduce the overall efficiency of the sector. However, to the extent that constraints are not a serious problem on the Swedish system, in that marginal costs do not differ greatly by zone, this loss of efficiency would be relatively small.

5.2.2. Ability of Traders to Hedge Risks in Sweden

As in Norway, Swedish traders cannot hedge the costs of congestion on electricity traded across the interconnections with Norway. Although the pricing of constraints is less explicit, this problem also applies to trades *within* Sweden. Buyers from the pool face little or no basis risk, since the congestion costs are averaged over the year and recovered through annual transmission charges. However, generators effectively face a potentially variable local price for "rebalancing" and have no facility to hedge the difference between the "rebalancing" price and the pool's market price.

There are three distinct cases of generators trading to rebalance the system within Sweden:

1) Generators constrained off. Constrained-off generators earn the system price in advance markets but "buy back" their energy at their bid price. Generators bidding prices which reflect their marginal costs and which have contracts hedging against the spot price are financially neutral to being constrained off (assuming stable costs). Their profits are at risk from variable levels of compensation only if their offer price differs from their costs (e.g. if they attempt to push their price down toward the local market value).
2) Single generators in import-constrained zones. A single generator in a constrained zone can set its offer price at a level which recovers its costs and therefore eliminate the risk to its profits, if regulatory policy allows.
3) Generators competing to supply in an import-constrained zone. In an import-constrained zone, the local market price will be set by the marginal generator called to increase output in that zone. Generators attempting to estimate this price (rather than just offering their costs) are subject to the profit risk associated with mis-estimation. (For example, a generator aiming too high may lose potential profits from not be called to run when it would have been efficient to do so.)

Insulating generators from the costs of being constrained off can also have longer term effects of generator's locational incentives. Generators have less incentive to locate in import-constrained zones and thereby "help" the system. The result could be more generation investment in export-constrained zones, higher levels of compensation in the short-term and unnecessary transmission investments in the long-run.

5.2.3. Muted Maintenance and Investment Incentives

Svenska Kraftnät has accepted responsibility for the cost of congestion (and losses) on the Swedish transmission system. Svenska Kraftnät bears the costs of constraints within Sweden in return for a fixed fee. However, Svenska Kraftnät is a state-owned organisation with a muted profit incentive. Profitability therefore provides little direct incentive to manage congestion and to invest in transmission facilities which might reduce losses and congestion. Moreover, while users bear the (expected) average cost of congestion and the marginal cost of

losses, they can only affect transmission investment indirectly through the regulatory process. As in Norway, a closer alignment of the responsibility for transmission investment with the risks of additional congestion and losses might result in more efficient transmission investment.

5.2.4. Incremental Users Do Not Pay Incremental Cost

In Sweden, new users pay part of the incremental cost of any large transmission investments precipitated by their connection. Although this approach is closer to incremental cost pricing than in Norway, the partial nature of the cost signal may still lead to inefficient siting decisions. When large transmission investments are called for, existing users may consider it unfair that they are required to bear even part of the cost of an investment precipitated by a new user.

Compared with the paradigm, there is another major deficiency in the Swedish system. New users may contribute towards the cost of reinforcement, but they do not get the right to use any associated capacity which they have created. New users in the same location may therefore be able to "free-ride" on some of the capacity created by a prior investment (particularly if economies of scale have meant that there is some spare capacity). In addition, the user financing the investment may no longer be able to capture the value of new transmission capacity, if a new user displaces them in the merit order. Users may therefore be unwilling to commit funds to facilities that they may not be able to use in the future. This feature of the Swedish system may discourage efficient transmission investments.

5.2.5. Sunk Cost Recovery

In Sweden, users pay for using the transmission system according to the capacity that they *choose* to "reserve" with Svenska Kraftnät. (In Norway, for the sake of comparison, charges are based on *installed* capacity and *metered* demand). There is some concern that users offering a net output might choose not reserve enough capacity to match their potential deliveries onto the grid. This could have two adverse consequences: distortion of despatch; and difficulty in recovering sunk costs.

The system affects the incentive to produce energy just at peak times. A short-lived increase in output at peak times requires the user to pay the additional transmission charge for the whole year. If the output level at peak times is only maintained for a few hours every year, then the additional transmission charge will make it appear very expensive to the generator - even though no actual cost is likely to be incurred, because the transmission facilities needed to accommodate maximum output have, in most cases, already been built. This penalty on short-duration peak output derives from the fact that transmission charges are avoidable annual tariffs, whereas transmission is provided in reality by assets whose original investments costs are long since sunk.

In itself, under-reservation of capacity should not threaten the immediate recovery of sunk costs; shortfalls in capacity reservations merely require Svenska Kraftnät to reallocate costs to those users who do reserve capacity. However, the longer-term consequences may be more serious.

The system of avoidable tariffs may encourage users to bypass the existing transmission system, e.g. by constructing their own lines to avoid Svenska Kraftnät's transmission charges. Users may choose to construct their own lines not because of the underlying economics, but simply to avoid paying the sunk costs of the existing grid. The result will be inefficient investment in transmission capacity. Self-generation is also a potential source of bypass if users can avoid transmission charges by reducing their net - but not their gross - requirements for transmission capacity. These risks will be heightened by the new European Union (EU) draft Directive on the Internal Electricity Market, which gives users the freedom to construct their own (direct) lines.

Although not subject to the EU directive, similar problems will also arise in Norway if users can avoid transmission charges by installing cogeneration or simply by leaving the system. Even the definition of "installed capacity" may become a regulatory issue, if generators wish to close down generation to avoid transmission charges. The problem is therefore not confined to Sweden.

To prevent uneconomic bypass, sunk costs should be recovered in a way which makes them unavoidable by users. New investments - whether in transmission or cogeneration - will then be appraised solely on their economic merits, rather than on the potential to avoid charges related to the sunk costs of past investments.

In the following sections, we address the economics of recovering sunk costs explicitly, in order to ensure that these long-term problems will not undermine the supposed efficiency of any system of transmission pricing.

6. DEVELOPING THE SYSTEMS OF TRANSMISSION PRICING

6.1. Nodal Pricing

As we discussed in section 5.1.1 above, the Norwegian system of spot pricing already closely approximates a nodal pricing system. There are unlikely to be any major benefits in implementing a formal system of nodal pricing in Norway. There may however be some benefits in moving the Swedish system closer to the Norwegian system - by introducing pricing zones within Sweden. This could be done relatively easily. Sweden already has loss charges that differ according to latitude. These charges could be amended to incorporate a "bottleneck fee" which reflected the marginal cost of constraints by location. In effect, this would establish a constraint-related price for each zone identified in Sweden.

The major benefit of introducing nodal or zonal pricing in Sweden would not derive from any improvement in the efficiency of despatch, which is unlikely to change very much. The main benefit of such a system - in Norway as well as in Sweden - derives from the ability of the grid companies and the traders to devise a system of Transmission Congestion Contracts for hedging transmission price risk. Offering long-term TCCs would also allow each grid company

1) to make transmission costs unavoidable, so that each network is less vulnerable to cost avoidance (e.g. by uneconomic by-pass); and
2) to apply a policy of incremental pricing for investment in new transmission capacity.

Since these benefits could be substantial, we examine in more detail below the process for introducing TCCs as a risk management tool, as a way of allocating sunk costs to make them unavoidable, and as the basis for pricing transmission at incremental cost.

6.2. Introduction of TCCs to Manage Risk

The main problem with the current system in Norway and Sweden has less to do with short-term pricing inefficiencies than the inability of traders to hedge congestion-related bottleneck fees. To solve this problem, each system would need to introduce Transmission Congestion Contracts (TCCs), to enable users to hedge the risk of variable bottleneck fees. In this section, we discuss how the Norwegian and Swedish Systems might introduce a system of TCCs.

6.2.1. Defining the Set of TCCs

Statnett and Svenska Kraftnät, or some other body (e.g. NVE), would first need to define a set of TCCs i.e. a complete set of (financial) rights to "use" the transmission system (i.e. to collect the benefits of usage). The total volume of TCCs should be broadly consistent with the available transmission capacity and must meet the feasibility rules described by Hogan,

Bushnell and Stoft. The party responsible for defining the set of TCCs would need to forecast a pattern of despatch for all future periods that meets the feasibility rules.

In many grid systems, defining transmission capacity is extremely difficult, since it depends on the pattern of despatch, which is itself a function of relative fuel costs and availabilities. In Norway and Sweden, the relatively simple nature of the transmission system may make this process easier. The volume of TCCs does not need to match an optional despatch, merely a feasible one. However, unpredictable variations in hydrological conditions may make it difficult to predict any feasible pattern of dispatch from year to year.

6.2.2. The Initial Allocation of TCCs

Traders will want access to TCCs to hedge the risk of inter-zonal price differentials. To achieve such a hedge, traders will want TCC capacity relating to the interfaces between the zones in which they are trading. The problem is to allocate the set of TCCs to individual traders in accordance with their needs. This can be done in one of two main ways:

- by auctioning the TCCs to traders;
- by allocating the TCCs to traders in accordance with some measure of historical use (e.g. their contribution to the sunk costs of transmission or their gross offtake from the grid).

The first method allows traders to express their requirements directly. The second method will not necessarily allocate TCCs to those traders which require them. Nevertheless, TCCs can then be reallocated to the traders who value them most highly, via a secondary market in TCCs. As we discuss in section 6.3 below, this method has some advantages.

6.2.3. Reallocating TCCs: The Need for a Secondary Market

The original holders of TCCs may eventually quit the sector and will want to have some way to pass on their TCCs to other users. If TCCs are made tradable, the original holder and the prospective buyer can negotiate a price for the transfer of the congestion rights. In addition, traders' transmission requirements will shift over time and they may want to adjust their TCC portfolios to manage their risk. A secondary market for TCCs, would allow traders both to offload and to adjust their TCC portfolios to meet their *current* hedging requirements. Nord Pool and brokers could play a role in ensuring the efficient operation of this secondary market.

A secondary market can lead to an efficient allocation of the TCC, if it allows those traders who most value transmission hedges to acquire those hedges. The initial allocation of TCCs is largely irrelevant to efficiency, if the secondary market allows contracts to be reallocated. To ensure that that the secondary market operates efficiently, however, it would be advisable to ensure that capacity over each major path was initially allocated to several companies, to create

a competitive environment. Otherwise, there is a risk that secondary market prices could be subject to market power exerted by dominant holders of capacity over key paths.

Given the large number of electricity companies in Norway and Sweden, it would appear relatively easy to divide any path between a number of them and so create a liquid and competitive market in TCCs over any route. Moreover, the extent to which traders can exploit any market power is limited, since other traders can continue to trade without TCCs (and thereby pay spot transmission charges or bottleneck fees without a hedge). Holders of TCCs can only restrict access to risk hedging, not to the transmission grid itself.

6.3. Dealing with Sunk Costs

6.3.1. Allocating Sunk Costs

An initial auction of TCCs will raise revenues for the Transmission Provider equal to the expected value of the TCCs (i.e. the expected difference in zonal prices for the duration of the TCC). However, given economies of scale in transmission, the revenues from an auction will probably not cover the full sunk costs of transmission. A supplementary method of cost recovery would therefore be required. Even if TCCs are allocated in some other way, a method must also still be found for allocating the obligation to pay for the sunk costs of the grid.

Section 2 advocated that sunk costs be allocated in the manner most likely to minimise the cost of capital. In practice, this means charging sunk costs to companies that have the most secure future revenues, such as distribution companies with a natural monopoly over distribution services to final consumers. The method used to recover sunk costs must also make them unavoidable, so that users have no uneconomic incentive to by-pass the existing system by investing in unnecessary transmission or co-generation facilities.

The allocation of sunk costs is a separate matter from allocating TCC capacity. In principle, distribution companies could pay the bulk of Statnett's and Svenska Kraftnät's sunk costs, while generators receive all the TCC capacity through an auction or an administered allocation. However, there might be some advantage in linking the payment of sunk costs to the capacity initially allocated in the TCCs (and vice versa). Distributors would then receive TCCs in return for meeting the obligation to pay the sunk costs of the existing grid. This has the following attractive features:

- equity - the benefits of holding the TCCs (or the expected benefits if the TCC is then resold in the secondary market) would flow pro rata to those that have met the sunk costs of the grid;
- the obligation to pay the sunk costs can be linked to the capacity of a financial contract, divorcing the obligation from actual levels of demand or pattern of grid usage. Payment of sunk costs by this method would not affect short-term incentives for efficient consumption and despatch, at least at the wholesale level;

- the liability to pay sunk costs cannot be avoided by by-passing the existing transmission system.

Not all distribution companies will want to be put to the trouble of buying power from distant generators and using the grid to bring it to their point of connection. Some will want to sign wholesale contracts for delivery of power to their own transformers. Since they will no longer require transmission capacity, but will in fact be exposed to the risk of variation in TCC rebates, such distribution companies may well sell their TCCs in the secondary market to those who are effectively using the transmission system.

The efficiency properties of a secondary market in TCCs are unaffected by this method of allocating sunk costs and TCCs. TCCs could still be transferred to those requiring them at their market value (equivalent to the expected congestion rentals). Buying capacity in the secondary market would allow generators to establish a trading business which "shipped" power over the network and offered wholesale contracts for power delivered to the point of exit from the grid.

6.3.2. Incentives to Final Consumers

The incentives to final consumers still depend on the design of consumer tariffs and the method chosen by distribution companies to pass on sunk costs. The ideal method would draw on the usual principles of Ramsey pricing and non-linear tariffs. For example:

- by allocating sunk costs in proportion to willingness to pay;
- by using fixed "customer" charges rather than kW charges for capacity; and
- avoiding any increase in kWh charges for consumption.

6.4. Incremental Costing of New Investment

Once there exists a procedure for defining transmission capacity, it would not be difficult to adapt it to cope with proposals for investment in new transmission facilities. Nordel or another co-ordinating agency might need to approve the technical design of the project, and there needs to be a forum for discussion of the effects of the project on existing capacity and on market prices. This forum would have to arrange for beneficiaries to meet and negotiate with those adversely affected, in order to ensure that only efficient investments proceed. Although time consuming, this process may not be vastly different from NVE's current role as arbiter on which transmission projects should be allowed to proceed.

Given the proposed commercial framework, any coalition can decide to commission new capacity and to choose the builder. New investment costs are therefore charged to the party responsible for commissioning the investment and are subject to competition. In these conditions, there is no need for the costs to be regulated.

In the specific case of a new generator, it may be that the generator agrees to pay for the dedicated assets associated with the "connection" facilities, but that distribution companies pay for any further reinforcements in the network. The boundary between the two types of asset is open to negotiation between the generator and the distribution companies.

6.5. Outstanding Issues

The discussion in section 4 identified a number of unresolved issues relating to the incentives of Transmission Provider and the despatcher to arrange maintenance and despatch efficiently. These concerns may be rooted in the monopoly characteristics of the two functions, which are simply not amenable to market-based incentives. For these reasons alone, it may be necessary to envisage some regulation of Statnett's and Svenska Kraftnät's revenues.

However, in the commercial framework set out above, the scope of such regulation is greatly reduced:

- total revenues relating to sunk costs at the time of implementing the system would be determined by the prices in long-term TCCs, thereby removing the need for future price reviews;
- additional revenues relating to new investment would be determined by the incremental cost of projects subject to competition;
- if the volume of TCCs matched the actual pattern of despatch, Statnett's and Svenska Kraftnät's receipts from bottleneck fees would be matched approximately by rebates on TCCs.

The scope of ongoing regulation would be rather limited:

- regulators might have to arbitrate over the price charged for the monopolistic roles of the Transmission Provider (including definition of capacity, arbitration over new projects, and setting technical design standards);
- similarly, regulators might want to check the costs and performance of the despatcher (including an audit of the optimality of despatch to check that nodal spot prices were not being manipulated);
- finally, regulators might be asked to arbitrate over particular costs and terms in TCCs, e.g. if they allow for unspecified adjustment in the light of some change in conditions.[18]

The system is therefore likely to significantly reduce the burden of regulation and offers the prospect of improved efficiency in the sector.

We are not aware of any system in the world which has succeeded in applying these principles. We therefore remain cautious when assessing the possible benefits in terms of the efficiency of decentralising transmission investment decisions. In the short-term, it seems that the major benefits of introducing nodal or zonal spot pricing and TCCs lie in the diminution of risk facing users of the transmission system. The extent of these benefits depends on the size of the risk

[18] In the US, gas regulators are often responsible for setting the cost of capital to be used in calculating prices in long-term contracts where the price formula allows for "floating" rates of return on certain assets.

facing traders (i.e. the size and variability of bottleneck fees) and on the impact this risk has on decisions about the location of generation relative to consumption. In Norway, bottleneck fees are significant and unpredictable, whereas in Sweden, the costs of rebalancing constraints - and the risk facing generators and consumers - appear to be relatively small. Demand for TCCs to complement nodal spot prices is therefore likely to be strongest in Norway, for good economic and commercial reasons.

7. CONCLUSIONS

In Norway, the current system of transmission pricing is already close to the theoretic paradigm associated with nodal pricing. In terms of despatch efficiency, there are therefore unlikely to be major gains in moving toward a system of nodal pricing from the current system for pricing constraints and losses. In Sweden, a move toward the Norwegian zonal pricing system would be relatively straightforward and might offer some efficiency gains if generators no longer had to estimate the local value of electricity when submitting offer prices. However, such gains are likely to be small, especially if the accuracy of central estimates of marginal values is reduced by the complexity of parallel flows on the Nordel transmission system.

The main problem facing traders in Nord Pool at present is the absence of hedges against variation (1) in bottleneck fees in Norway and (2) payments to constrained generators in Sweden. It does not appear to be impractical to define and allocate Statnett's and Svenska Kraftnät's transmission capacity through TCCs. This would help to provide all traders with the ability to hedge basis risk. Creating a competitive secondary market in TCCs also appears to present few obstacles and there is every reason to expect that capacity would be reallocated among electricity traders in an efficient manner.

Finally, a system based on TCCs would potentially provide the following additional benefits:

- it provides the transmission providers with an incentive to maintain existing transmission capacity;
- it allows decentralisation of new investment decisions (subject to an appropriate forum for forming coalitions and to deal with transfers within zones); and
- it provides a secure and efficient way of allocating sunk costs.

We have described how such a system would work and what regulatory problems remain to be solved. We doubt whether there will be much pressure for the introduction of the full system, with incremental cost pricing of new capacity, unless existing users begin to express concern over the allocation of the cost of connecting new users. However, in the long-run, as investors in generation adjust to the newly competitive environment, pressure for reform of transmission pricing is likely to grow. A system of nodal spot prices and long-term TCCs would provide the basis for efficient decentralisation of decisions about investment in, and use of, the transmission systems of Norway and Sweden.

APPENDIX 1. THE COSTS OF TRANSMISSION LOSSES AND CONSTRAINTS

1.1. Transmission Losses

Transmission losses increase with the flow over any line and the short-run marginal cost (SRMC) of any particular request for transmission will therefore depend on existing flows on the transmission system. To identify marginal costs, we therefore need to consider the cost impact of additional flows on the system. For example, any generator supplying an additional 100 MWh at Node A may find that customers at Node B can only draw off any additional 95 MWh. In this case, the marginal physical losses would be 5 MWh.

The marginal cost of moving electricity from Node A to Node B is easily defined in terms of these physical losses. If the marginal cost of generation at Node A is $10/MWh, the total cost of the additional 100 MWh will be $1000. Customers will only receive an additional 95 MWh, but will still need to pay an additional $1000 to cover the generator's incremental costs. This implies a price for the additional generation at Node B of $1000 ÷ 95 MWh = $10.53/MWh. Hence the implied cost of moving energy from Node A to Node B has increased its price by 53 cents/MWh; this price increase defines the SRMC of transmitting electricity from Node A to Node B.

1.2. Transmission Constraints

We can derive the cost of transmission constraints from a similar two-node example. To simplify the exposition, we will assume for the moment that losses between these two nodes are zero. The short-run cost of a transmission constraint is defined by the difference in the marginal cost of energy at two nodes.

We have two nodes one with high production costs, the other with lower production costs. Without a constraint, the marginal cost of transmitting energy between the two nodes would be zero. Total costs could be reduced by increasing production at the low cost node and decreasing production at the high cost node. In the absence of a constraint, this would continue until the marginal cost at each node was the same and there was no scope to reduce total costs further. However, the presence of the constraint prevents the equalisation of the marginal costs; the *opportunity cost* of the constraint is then defined by the difference in the energy costs at the two nodes.

This can be demonstrated graphically as follows. Figure 1 shows a simple generation supply curve at the low-cost production node A. Given a level of demand OX (invariate in price for the sake of simplicity), the spot price emerges at the system marginal cost of $12/MWh.

Figure A1.7-1: Zone A Generation Costs

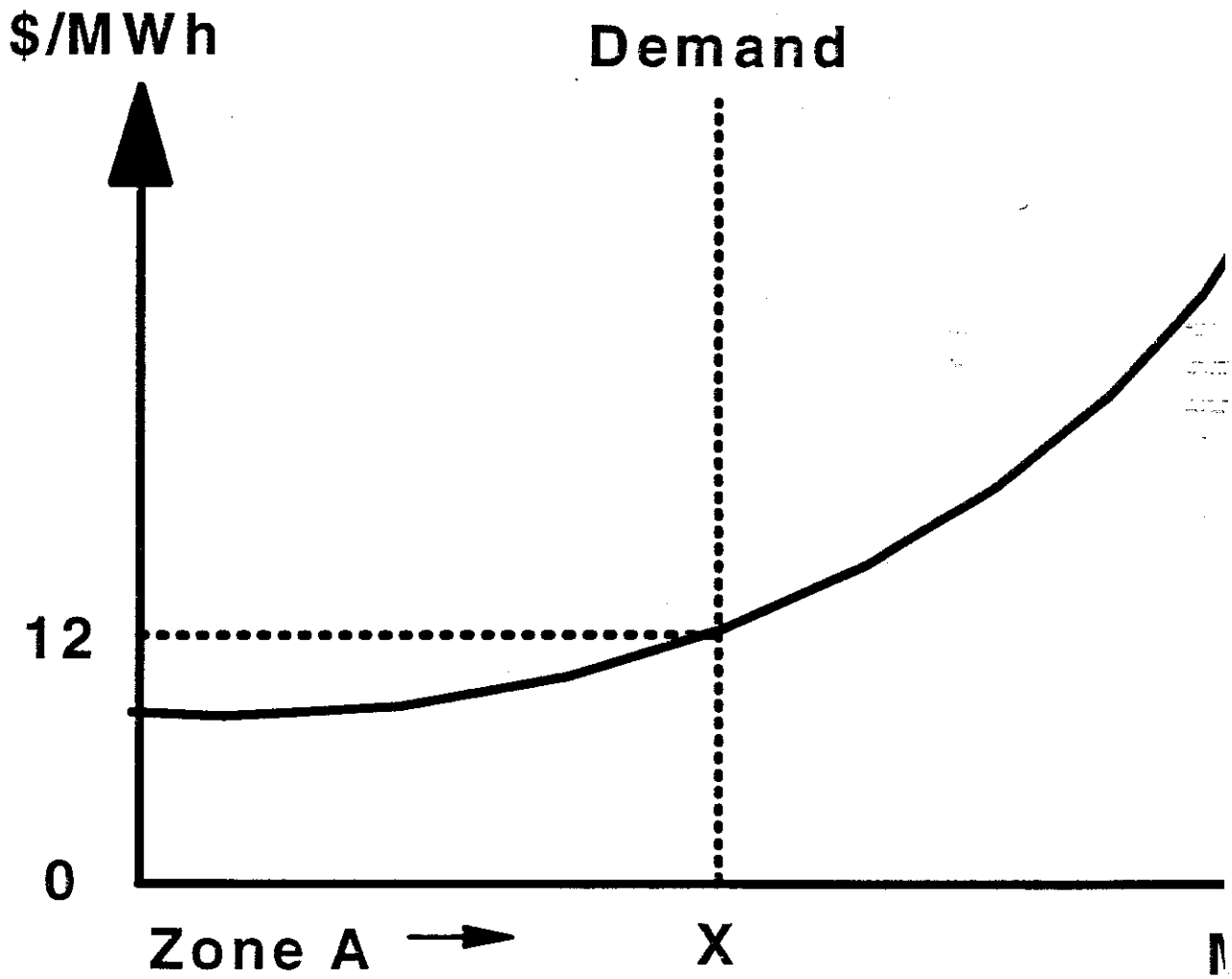


Figure 2 shows a similar situation at the high-cost production node B. Here, demand of OY produces a price of $20/MWh.

Figure A1.7-2: Zone B Generation Costs

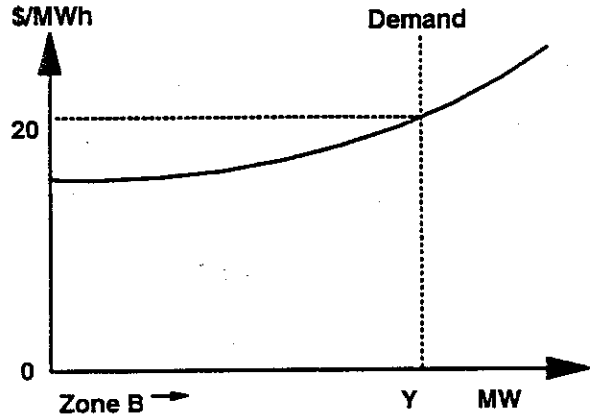
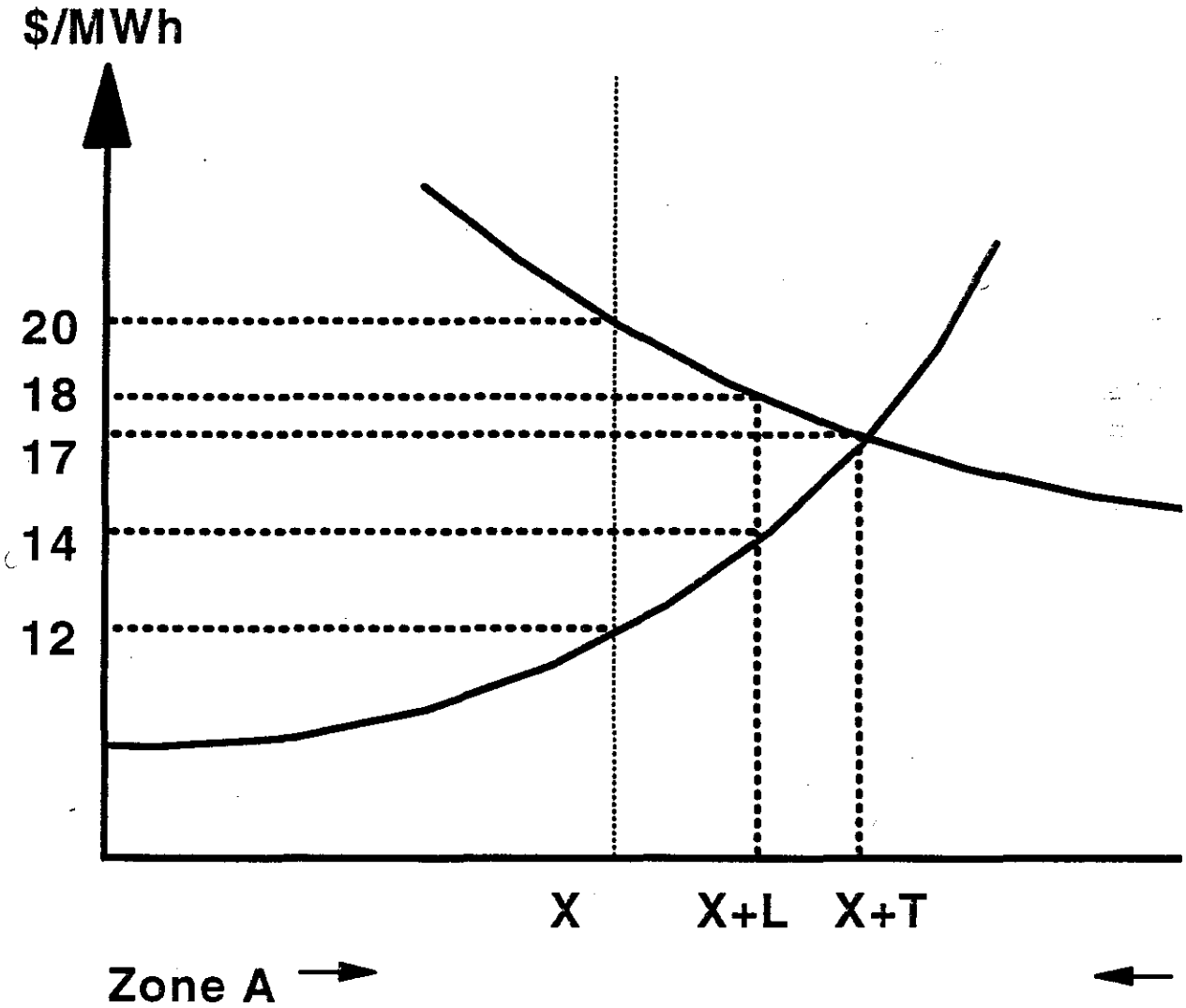


Figure 3 shows the effect of linking the two nodes with an interconnector that has a capacity in MW of L. (We will discuss later what determines the size of such interconnectors.) In Figure 3, Figure 2 is first turned around so that it reads from right to left. Then it is placed back-to-back with Figure 1, so that the total width of the diagram is equal to the combined demand at nodes A and B, or X+Y. The task of an efficient despatcher is now to minimise the cost of meeting the combined demand.

Figure A1.7-3: Joint Generation



Given the availability of low-cost generation at node A, the despatcher will increase output at node A, to displace high-cost generation in node B. The marginal cost (and zonal spot price) will rise in zone A to $14/MWh; in zone B, it will fall to $18/MWh. At this point, the interconnector is fully loaded.[19]

[19] If transmission capacity were equal to T MW or more, the rebalancing of despatch would continue, until both zones reached a marginal cost of $17/MWh, at which point they would become one market.

The difference of $4/MWh between the spot prices in zones A ($14/MWh) and B ($18/MWh) represents the opportunity cost of transmission over the interconnector in several different respects:

- The loss of 1 MW of capacity for one hour (i.e. 1 MWh of transmission) would require generation to increase by 1 MWh in zone B (at a cost of $18) and to decrease by 1 MWh in zone A (at a saving of $14), so the availability of a marginal (decremental) unit of capacity reduces total generation costs by $4/MWh.
- Any trader would pay up to $4/MWh for the right to move power from zone A to zone B, that being the value of the right in terms of additional profit opportunities.
- Any trader who possessed the right to move power from zone A to zone B would demand no less than $4/MWh to give up the right, that being the profit he would lose by doing so.
- Below, we will also discuss how the value of $4/MWh relates to the cost of expanding transmission capacity over the link.

Hence, the short-run marginal cost of transmission from A to B is defined by the difference between spot prices at A and at B.

1.3. Generalising the Analysis to Several Nodes

The analysis above of losses and constraints applies equally to systems with more than two nodes. However, in a multiple-node system, the marginal source of generation to meet an increase at node M is more likely to come from a generator at node N. Increased demand at any one node will also affect the flows - and hence the pattern of constraints and losses - at all other nodes on the transmission system. This means that the nodal price for zone M cannot be calculated from production costs at node M alone or from a simple loss-adjustment to production costs at any other single node.

In practice, an optimal power flow model may be needed to define an optimal despatch given the physical characteristics of the transmission system and the location and marginal cost/valuations of generation and demand. Based on this optimal despatch, the marginal cost of meeting demand at any one node can be calculated by considering the marginal effect on total costs of meeting that increment (i.e. the "shadow value" or "opportunity cost" of energy at each node on the transmission system). However, the basic principle of the two-node model still applies i.e. the difference between the marginal cost of energy at any two nodes defines the short-run marginal cost of transmission between those nodes.