LONG-TERM INVESTMENT IN ELECTRICITY: A TRADE-OFF BETWEEN CO-ORDINATION AND COMPETITION?

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Abstract: The purpose of this paper is to explain the theoretical debate and the practical problems concerning long-term investment in electricity. It analyses fundamental aspects of investment in electricity such as the interdependencies between generation and grid investment, free-riding problems, and the investment signals of different network access regimes. Especially the externalities that are created by the nature of electric flows pose severe problems for investment decisions. The way these externalities are internalised in the pricing scheme strongly influences where rents are collected and investment is profitable. Besides, the handling of the loop-flow phenomenon is crucial for the trade-off between co-operation and competition in long-term investment in electricity.

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1 Introduction

During the summer of 2003, the public focus concentrated on the need for investment in new transmission and generation assets. The question was raised whether deregulated electricity markets could create sufficient investment incentives. With the opening of the electricity markets, a once fully vertically integrated industry was vertically separated into competitive elements (generation and sales) and regulated monopolistic elements (transmission and distribution). Going along with the separation of generation and transmission responsibility, new challenges arose in enhancing competitive elements and ensuring co-ordination of grid use to guarantee electricity supply.

Different frameworks have been developed in theory and practice to address the problem of interaction between generation and transmission. In a perfect market environment, a pricing mechanism takes over the part of co-ordinating the actions of market participants since this provides the most efficient results. This is in general also the case for investment decisions. In the electricity industry, under vertical integration one utility was able to jointly optimise generation, transmission operation, and investment. After deregulation, the decision to invest in generation on the one hand and network infrastructure on the other hand are taken by separate firms, rather than one integrated utility. While the traditional cost-of-service approach to regulation has favoured over-investment in generation and transmission assets, now the problem of under-investment is discussed. Since maintenance and modernisation of the grid are primarily in the responsibility of the network owner, so-called merchant (or market-based) investment in new lines (especially in new links or interconnectors between regional networks) may be undertaken by third parties (Joskow/Tirole 2003). Merchant investors try to profit from scarce capacity between regions by building (DC) lines to skim rents. This paper concentrates mainly on investment in new lines and the possibly resulting trade-offs between

(1) investment in transmission and investment in generation,
(2) co-ordination and competition.

These topics are linked closely by the transport characteristics of electricity. This makes it more difficult to estimate the "right" amount of investment. Beside the economic calculation of market participants a regulatory framework tries to implement general interests such as security of supply and systems reliability. To sketch the issues, the following table provides an overview of problems connected with long-term investment in electricity.

<table>
<tr><th>Issue</th><th>Generation</th><th>Transmission</th></tr>
<tr><td rowspan="2">security of supply / adequacy</td><td colspan="2">“Security is the system’s ability to withstand sudden disturbances, while adequacy is the property of having enough capacity to remain secure almost all of the time.” (Stoft 2002: 133) How much is “enough” capacity? Who knows best/decides?</td></tr>
<tr><td>Is there a need for capacity markets?</td><td>Investment need and responsibility?</td></tr>
<tr><td rowspan="2">regulation and distortion of transmission investment incentives</td><td colspan="2">Danger of over- or under-investment induced by regulation.</td></tr>
<tr><td>Due to distortions in transmission investments distributed generation may increase to bypass the transmission system.</td><td>(Partial) cost pass through mechanisms?</td></tr>
<tr><td rowspan="2">market design and investment signals</td><td colspan="2">Who knows where to invest?
Depending on the market design, signals for investment in transmission may be provided for all market participants or only for the system operator.
Trade-off between investment in generation and transmission?</td></tr>
<tr><td>Influencing the location of new units can decrease transmission congestion.</td><td>Merchant investment in transmission or investments by the transmission owner? Co-ordination of both?</td></tr>
</table>

Table 1: Questions associated with investment in electricity

Given the overview in table 1, this paper concentrates on market design and price mechanisms and their inherent investment signals. It neither explores the effect of a single regulatory mechanism as a revenue or price cap on investment incentives nor discusses the possible demand for security of supply which might enter the investment level (Wild/Vaterlaus 2003).

The contribution concentrates on investment in generation assets and transmission networks analysing information and co-ordination needs and what might be left to competition. Its primary aim is to explain the technical problems of transmitting electricity and their implications for investment decisions. Secondarily, transmission pricing mechanisms and the resulting investment-incentive schemes are presented. The paper is organised as follows. With section 2 possible impediments to transmission investment, especially the trade off between generation and transmission investment, is analysed. Section 3 explains different effects on investment incentives of a usage fee aiming at short run efficiency. With the market design and especially the pricing mechanisms long-term investment signals should be provided. This focuses on the trade-off between co-ordinating elements in the market regime and competitive ones building primarily on pricing mechanisms. Section 4 concludes in formulating possible solutions to the trade-offs presented.

2 Possible impediments to transmission investment

In this section, several possible impediments to transmission investment are discussed. In addition to impediments closely related to the characteristics of the transport network itself, such as lumpiness, loop flows and interdependencies between investment in transmission and generation assets, the investment decision might be influenced by regulatory risk and public resistance.

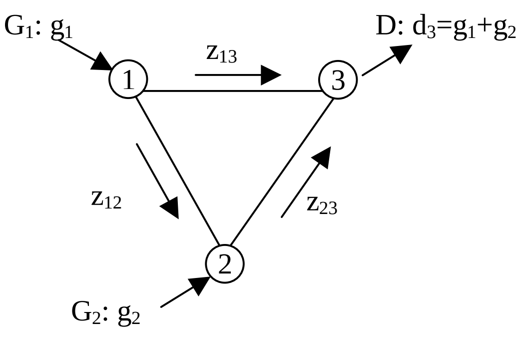
2.1 Lumpiness of grid investments

Transmission lines are characterised by significant economies of scale leading to problems in cost recovery (Baldick/Kahn 1993). It follows that (merchant) transmission investment is only profitable if the discounted value of earnings from sales of new transmission capacity exceeds investment plus operation costs. Earnings from transmission will be the higher the more congestion occurs. Since investment in transmission capacity is characterised by significant fixed costs (fixed-step costs), new transmission lines typically eliminate congestion that used to be present in the corresponding part of the network. Because of this lumpiness of transmission investment, investment will only be profitable if the network constraint partly persists after investment. If congestion is fully eliminated, no congestion rent can be extracted from the network users to cover investment costs.

2.2 Loop flows

Due to the laws of physics the flow of electricity cannot be totally controlled since it follows the path of least resistance. Because of that, it is misleading to price the use of the network with the aid of a contract path principle based on the fiction of one definite path between the point of injection and the delivery point. It ignores the laws of physics that govern the transport of electricity (causing loop flows), the actual flow pattern, and congestion. Concerning investment this may lead to free-rider problems when investment decisions of one network owner induce positive externalities in other networks.[1]

The transmission network within a country, however, consists of various nodes connected by lines. The power flow then follows parallel paths according to Kirchhoff's Laws. In doing so, the possibility of third parties to inject and withdraw energy is influenced, which can be described as an externality. A three node network is the simplest way to introduce the external effect of these so-called loop-flows (Hogan 1992, Stoft 2002: 397). Figure 1 depicts a network consisting of two generation nodes (1 and 2), one load node and three lines. The lines have the same length and impedance, so that the impedance from 1→2→3 is twice as high as from 1→3. Therefore a certain amount of power injected in node 1 divides itself into two-third using line z_{13} and one-third taking $z_{12} \rightarrow z_{23}$ to get to node 3. On line z_{12} the power flows from node 1 and 2 are opponent so that only the net-flow remains. Assuming that the generation unit at node 1 injects more than G_2 the indicated flows result.



$$z_{12} = \left| \frac{1}{3} g_1 - \frac{1}{3} g_2 \right| \leq z_{12\,max}$$

$$z_{23} = \left| \frac{1}{3} g_1 + \frac{2}{3} g_2 \right| \leq z_{23\,max}$$

$$z_{13} = \left| \frac{2}{3} g_1 + \frac{1}{3} g_2 \right| \leq z_{13\,max}$$

Fig. 1: Loop flows and resulting line flows

Taking these laws of physics into account the following example underlines that there are serious interdependencies between injection, network flows and the actual

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[1] As an example: Adding network capacity in Idaho would be the most efficient way to increase flow

capacity of a network. Figure 2 depicts four different injections and congestion situations within the network described above. It becomes clear that the determination of the capacity of a network depends on current injections and withdrawals.

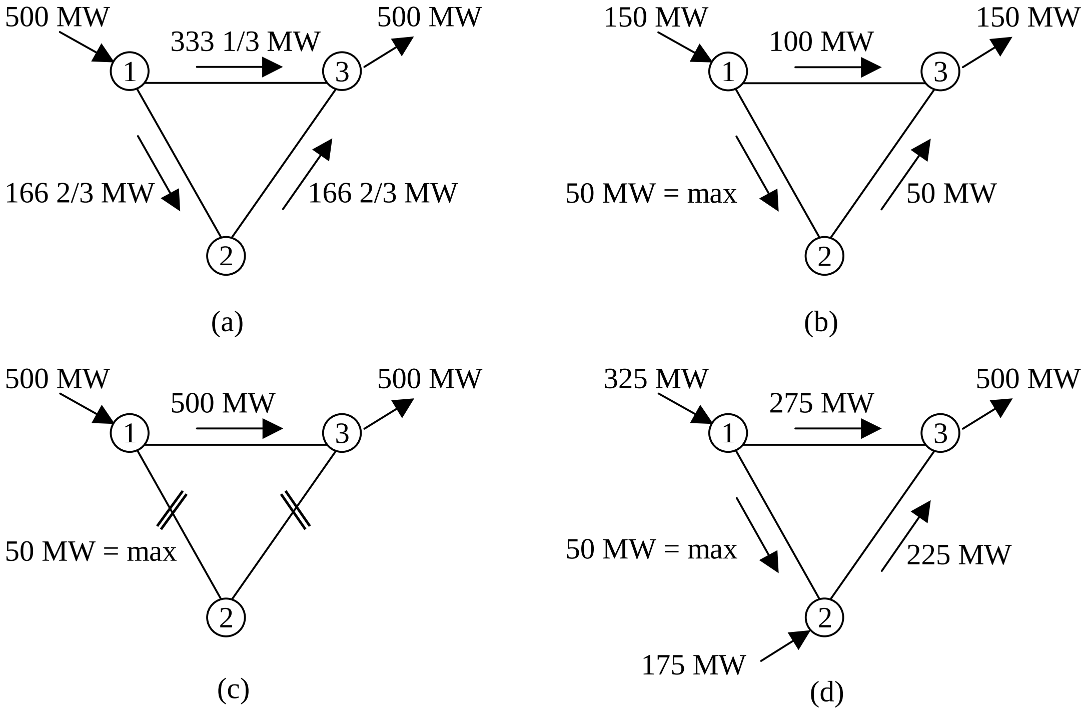

Fig. 2: Loop flows and capacity

Case (a) faces no congestion problems. The generator at node 1 provides the electricity withdrawn at node 3. Introducing a capacity constraint of 50 MW on line (1,2) as is the case in (b) makes it impossible to withdraw 500 MW at node 3. Given the laws of physics, only 150 MW can be injected by the generator at node 1. At node 3 a scarcity rent has to be collected to shorten demand to keep up the network equilibrium. Facing the constraint on line (1,2), is it still possible to get 500 MW at node 3 without line upgrading? Scenarios (c) and (d) offer two solutions: First in (c) the topology of the network is changed since node 1 is no longer connected to line (1,2). Due to that, all 500 MW flows over the one-line-network connecting node 1 and 3. The special character of transmission becomes clear with case (d). Co-ordination of the injections at node 1 and 2 mitigates the constraint. As a result compliance with the restriction can be observed: $1/3 \cdot 325MW - 1/3 \cdot 175MW = 50MW = max$.

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capacity from the Pacific north-west into California (Bushnell/Stoft 1997: 88).

Since modifications in the topology of a network with many nodes and lines induce over-all changes in flows, the balancing of the constraint by injections is the only solution to guarantee the withdrawal of 500 MW at node 3. Therefore the equilibrium in the network can be guaranteed by the SO telling each generator how much to inject or by internalising the externalities in a transmission pricing scheme that produces (nodal) prices determined by the current network condition.

2.3 Interdependencies between transmission and generation

Location of generation influences network congestion and vice versa

One signal that there is a need for investment (that investment might be profitable) are price differences on the wholesale markets for electricity of different regions or price differences occurring in locational pricing systems. One example is the price difference between the Netherlands and Germany reflected in the scarce interconnection capacity between the two countries.

Facing a “high price” and a “low price” country, investment either in generation capacity in the “high price” country or in interconnection capacity (or in both) might be profitable. Therefore, depending on the specific scenario, generation and transmission capacity are partial substitutes. So, first of all, there is the question whether to invest in transmission or generation capacity. The following examples show that there is no clear solution to this trade-off. Looking at a one-line-network (that might as well be an interconnection between two electricity markets) there exists a scarcity rent in case of scarce generation and scarce transmission capacity. Figure 3 depicts a one-line network connecting a generation unit located at node 1 with constant marginal cost of generation and a given maximum generation capacity with a relatively inelastic load situated at node 2. Line losses are not taken into account. Ignoring losses, the variable cost of using the network are zero as long as no capacity constraint occurs. Due to capacity constraints in generation and transmission, respectively, the demand has to be restricted to 500 MW, so that a scarcity rent emerges.

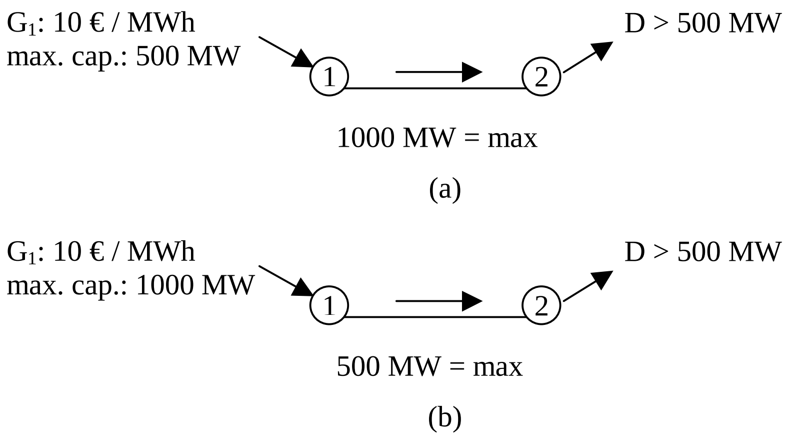

Fig. 3: Scarcity in generation and/or transmission

In case (a) the transmission line can be neglected and the price per MW is determined by reducing the excess demand by elevating the price of power over marginal cost of generation. This might be done in a power exchange or by bilateral trade. As a result the generator earns a surplus. In case (b) the system operator (SO) has to ensure that the capacity limit of the line will not be damaged. Depending on the market design, the SO restricts transmission on the congested line by discretion or by a network usage charge. Using a price system, the SO earns a congestion rent. Taking rents as a signal for investment need, in both cases scarcity would be relieved, if new generation capacity was built. Since there is enough transmission capacity, in (a) new generation units might be built at node 1 or 2, while in case (b) investment in generation should take place at node 2. Only in (b), new transmission capacity could also relieve congestion and scarcity.

Network investment influences profitability of generation and vice versa

Firstly, one cornerstone for investment in *generation* is to compare demand (especially in times of peak demand) within a given network area and available generation capacity. Taking demand into account, investment in transmission capacity makes no sense within a network in which the installed generation capacity is scarce since the missing generation capacity cannot be replaced by the SO. Since generation capacity is provided competitively, the need for it should be reflected in the market price on the wholesale level.[2] Leaving the decision whether to invest in generation to the market, leads to a first caveat for the regulatory authority: Only free floating prices ensure that there are signals for an adequate level of investment in generation. Capping prices on a competitive market with the aim of protecting customers destroys investment incentives.

Secondly, (b) provides an example of a possible trade-off between investment in generation at node 2 and in transmission capacity. In a vertically integrated firm this trade-off has been solved by minimising overall cost. In an open market investment incentives should (if possible) do the job. In this context, Stoft/Tabors (1999) provide an example of a possible implementation of the generation transmission trade-off by criticising the proposed revisions of the transmission tariffs by the Transmission Administrator (TA) of Alberta. They put the problem as follows: First of all, a transmission operator knows nothing about generation costs which should be determined by the market. With positive incentive (credits) the TA uses a market signal to find out whether it is better to invest in generation assets or transmission. “Consequently whenever the TA can reduce transmission upgrade costs plus generation incentive costs (two costs it knows well) it also knows (because of the market signal) that it has reduced the total cost of generation and transmission (only one of which it knows)” (Stoft/Tabors 1999: 26). Leaving the decision to the TA whether he would like to pay a certain amount to generators saving the higher investments in transmission assets seems to be a very special solution that is restricted to a certain market design.

Is there a need for co-ordination of investment in generation and transmission?

The interdependencies between investment in generation and transmission seem to induce a certain need for co-ordination or information of the different parties involved in the process. Because of interdependencies, lumpiness and lifetime of investments the risk of investment seems to be higher than in other competitive industries. In addition there is an information asymmetry between generation investment by

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[2] For the analysis of market power and oligopoly structures on the generation level see Léautier 2001. Concerning generation capacity there might be a problem with capacity in times of peak load. To address this, VOLL (value-of-lost-load pricing) or ‘price-caps’ on generation have been developed; see Stoft 2002: 111ff. and OECD/IEA 2002.

vertically integrated firms and new entrants concerning the expansion and upgrading of the network infrastructure. On the other hand, investment in generation leads to a need for investment or upgrading in transmission so that the network owner may wish to incentivise the location of generation assets.

2.4 Regulatory commitment

All of the issues discussed above contain serious information problems and asymmetries. On the one hand, a regulatory body generally has less information concerning the actual state of the grid and generation assets than the system operator and the generators. On the other hand, the transmission owner has to deal with a regulatory risk which negatively influences investment incentives. This is due to the so-called hold-up problem. Once the investment is made, the regulator may act opportunistically and enforce his regulation towards lower prices. Therefore, credibility of regulatory decisions is a further requirement for sufficient investment incentives.

2.5 Resistance against new lines

The construction of new transmission lines is almost impossible, due to opposition from residents in the affected areas. “The United States has gone BANANAS – Building Absolutely Nothing Anywhere Near Anybody” (Hunt 2002: 206). Since nobody wants to have electricity lines in his backyard, the installation of such lines causes negative externalities in terms of decreasing land value and disfiguring of landscape. An attempt to overcome the resistance against new lines is to take these externalities into account e.g. in offering financial compensations, which have to be considered as costs of the investment.

3 Transmission pricing and investment incentives

3.1 Market design and transmission pricing

In theory and practice various market designs for power markets have been developed. Depending on the transmission pricing mechanism, incentives and signals for investment in generation and/or transmission capacity are provided. In analysing what kind of investment signals occur, first of all, the question of how network access tariffs are determined has to be investigated. Here prices shall guarantee short-term efficiency in reflecting the marginal cost of production (for the generation stage) and the marginal cost of usage of the transmission network. Due to economies of scale in the network infrastructure, in addition to the usage fee a fixed network access or connection fee is charged. The following paragraph concentrates on prices reflecting marginal cost leaving aside fixed charges.

The basic ingredients of a transmission pricing mechanism can be illustrated with the aid of the following cube (figure 4).

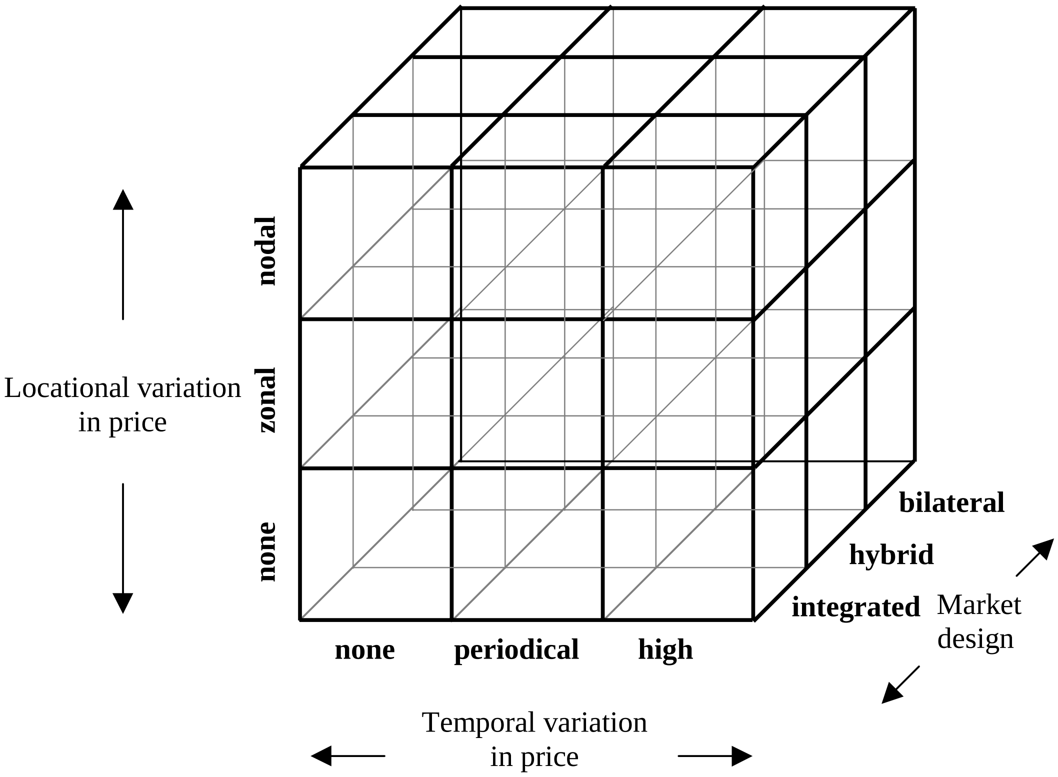

Fig. 4: Market design and price differentiation in transmission usage charges[3]

With the **variation in time**, the pricing scheme applies the well-known peak-load pricing mechanism (Steiner 1957; Boiteux 1957, Crew/Fernando/Kleindorfer 1995). Since demand fluctuates over time, its contribution to marginal cost of capacity varies. The length of one period of time may differ. Implemented systems choose a variation between ½ hour (as the former pool of England and Wales) and 5 minutes (PJM). There might be a certain trade-off between the number of pricing periods within 24 hours and the effort of metering, but shorter time periods should provide more efficient signals since the variations within these period are smeared over shorter periods.

The **locational variation** of prices takes into account the physical laws governing the flow of electricity. Injections and withdrawals may induce loop flows with congestion cost. These externalities are partly internalised with different nodal prices. Choosing a pricing system with no locational variation might be a sign for few capacity problems whatever flow occurs.

The **market design**[4] refers to the way prices on the wholesale market are determined and whether they involve generation and transmission payment. Integrated systems imitate the former vertically integrated utility in minimising the cost of serving demand subject to transmission constraints and generation limits. Bilateral markets price energy, transmission, and reserves separately while hybrid forms lie in between (Wilson 2002).

To address the problem of investment within the possible specifications of transmission pricing schemes, two specifications are presented briefly. Special emphasis should be put on the way the externalities are internalised in the pricing scheme. This strongly influences where rents are collected and investment is profitable.

The combination of a bilateral market design and no locational or timely variation in prices as one corner of the cube leads to a postage stamp tariff (€/MW) for the use of the network. For calculating the unit rate the cost of the network is divided by the sum of MW used at systems peak. Thus, this pricing principle does not take into account congestion situations and the actual system operation. System externalities are not reflected in individual prices but spread over all network users. Incentives for investment in generation are derived from the prices on the wholesale market for

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[3] Taken from Keller 2003.

[4] Wilson 2002 differentiates between integrated, unbundled and hybrid markets. The term “unbundled” might be confusing since it is also used for describing the separation of the value chain of a formerly integrated utility.

electricity that fluctuate in time and permit differentiation between investment needs for different types of generation assets (peak time, base load, etc).[5] The status of grid investment can be described as a black box for all market participants beside the SO. Investment in generation may lead to upgrading needs that could be avoided by signalling where new generation assets are neutral or welcome.[6]

In nodal pricing systems based on an integrated view of generation and transmission activity, system operation and market operation go together very closely. The market operator runs the spot market so that the cost of meeting demand are minimised, subject to transmission constraints. All generators bid their amount of energy and their price in the system. In a very simple case when there is no congestion in the network, the merit order is reached. All generators are paid the amount the last producing generator has demanded. Ignoring losses and congestion, prices are the same in the whole network (i.e. the system marginal price). In case of congestion the demand cannot be covered by the cheapest generators. Some of them are constrained-off and replaced by more expensive units since the injection of cheaper energy would have endangered the stability of the network. This results in different prices for each location. So, in a nodal pricing system, on every node the price is set equal to opportunity cost as represented by the offers and incorporates cost from congestion and need to re-dispatch. A modification of nodal pricing is a zonal pricing system in which the calculation of prices is not done for every single node but for zones made up of different nodes. Price differences therefore can be found between different zones, rather than within one zone. The so-called market splitting as it is used in the Nordic Power market is a prominent application of zonal pricing. Price differences between nodes and zones may induce incentives for investment in transmission capacity and high prices represent a signal for investment in generation units at this node / in this zone.[7]

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[5] For generation, expansion and revenues see Rothwell/Gómez 2003: 111ff.

[6] The installation of wind energy converters in the North of Germany induces network upgrading costs that are neither reflected in connection nor usage charges. The costs are smeared over all network users. Sacharowitz 2003.

[7] A problem with nodal and zonal prices is that pricing according to marginal cost is not able to cover the cost of the network. To cover fixed cost an annual access charge is normally raised. If investment signals are provided through price differences between nodes, it is under discussion whether there should be a locational element in the access charge, too (Hunt 2002: 200). On the one hand, this enforces the investment signal but, on the other hand, in a network with changing congestion situations it may contradict the signals provided by the nodal prices.

In its earlier versions locational pricing models only included a spot market (Schweppe et al. 1988). Because network users accentuated the need to protect themselves against price variations in time and location, so-called contracts for differences (to hedge against price fluctuations in time) and financial transmission rights (FTRs, for locations) have been introduced.[8] In the following, the focus is on the locational elements since they are the most important factors for investment incentives. A nodal pricing system supplemented with FTRs gives their holders the possibility to hedge against the uncertainty of varying transmission usage charges at their nodes. A FTR is the right to collect a share of congestion rent between one defined node of the system and another. The price difference between these two nodes times the quantity of rights is paid to the holder. Although it constitutes a financial right it is connected to the precise flow of energy.[9] FTRs are supposed to reflect the congestion situation of the grid; the flow resulting from the allocated FTR set must be feasible regarding the specification of the grid. If this is not the case, the congestion rents collected by the system operator may not be sufficiently high to cover the hedge payments (cf. Hogan 1992; Stoft 2002: 438 ff.). Since the earnings from FTRs need price differences between the specified nodes, there is also an incentive to complete the grid with “inefficient” links to get congestion rents. Bushnell/Stoft (1996a,b and 1997) provide an example with an investment leading to significant negative effects on the system. To overcome this problem they suggest that the effect of the investment on the whole network should be taken into account. It is crucial that new investments and resulting FTRs lead to a feasible dispatch and take existing FTRs into consideration. Here a co-ordination problem concerning investment and resulting FTRs in different periods occurs.[10]

3.2 Investment incentives: competition and co-ordination

It has been shown that network usage pricing is a crucial element with respect to investment signals in generation and transmission. Leaving investment in new lines to merchant elements alone would enhance the competitive factor in the area of the grid

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[8] This is mainly the effort of W.W. Hogan. See Hogan (1992) and the various publications on his page: http://ksghome.harvard.edu/~.whogan.cbg.ksg/

[9] There is no need to own FTRs to get on the grid. This is an important difference between FTRs and physical transmission rights.

[10] Hogan (2002) discusses these issues in detail and Rosellón (2003) provides an excellent overview of the literature concerned with FTRs.

monopoly but may induce serious problems designing investment incentives and long-term property rights. Only with locational price variations, signals for investment in transmission are provided for third parties. To avoid negative effects on the grid, FTRs have to be defined with care, taking into account the externality the investment involves. Given that this is the case, the trade-off between investment in generation and transmission is not yet addressed. At least some co-ordination in the form of information for all market participants on planned transmission investment seems to be necessary. Since generators depend heavily on the grid, they will invest only if the nodal price in question lies above their marginal cost.

Signals for the location of new generation units can easily be implemented in uniform pricing systems. The network operator should be interested in providing such signals with the aid of access or connection charges since this increases network reliability and may reduce the need to install new lines. The trade-off between new lines and generation assets might be solved by favouring new generation units from a regulated network owner's point of view. Table 2 summarises the competitive elements and co-ordination provided by the investment signals of different pricing structures.

Pricing structure	**Generation**	**Transmission**
uniform pricing	Incentives for investment in generation assets are derived from the wholesale price of electricity by the individual firm. With locational differentiation in network access/connection charges, the investment might be directed within the network area.	No investment signals for third parties. Market based investment only between different networks not within one network area. Information for investment needs only known to System Operator (SO). Separation of TO/SO might cause co-ordination problems.
nodal/zonal pricing	Incentives for investment are provided by high nodal prices inducing market entry of generators at the node in question. Need for co-ordination of transmission and generation investment?	Price differences between nodes reflect different marginal cost and may induce market-based investment. Due to lumpiness of investment, underinvestment problems remain. Need for co-ordination of market based investment and investment by the system owner?

Table 2: Pricing structure and investment

4 Concluding remarks

Leaving the construction of new lines to merchant investments alone, needs a very sophisticated pricing mechanism with long term rights, which might be too complicated to implement. The characteristics of transmission and interdependencies offer opportunities and risk to all participants. In the face of transaction cost and imperfect information it might be better to choose an approach involving some co-ordination (e.g. a co-ordination group of all parties involved) instead of too much reliance on the market. Furthermore, to exclude free-rider problems and information lacks, a certain degree of co-ordination is in conformity with the interests of all parties involved. Facing the market regime, it should be discussed how a co-ordinating institution might be established and what competencies and tasks it should have. An example for the organisation of such a group is provided by the Regional Transmission Expanding Planning Process within the network of PJM (PJM 2003).

The trade-off between co-ordination and competition in long-term investment in electricity constitutes a long-term problem in itself: “A significant research challenge is to design regulatory mechanisms for system operators and incumbent transmission owners and a better framework for defining transmission property rights that will stimulate efficient investment by regulated incumbent transmission owners and by merchant entrants responding to market opportunities when they are the most efficient suppliers.” (Joskow/Tirole 2003: 1)

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