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MARKET-BASED INVESTMENT IN ELECTRICITY TRANSMISSION NETWORKS: CONTROLLABLE FLOW

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Abstract: This paper discusses unregulated market-based electricity transmission investment by third parties as opposed to regulated investment by designated transmission system operators. The analysis is set against a European and Australian institutional background and focuses on interconnection of different systems. The paper explores four areas: economies of scale, market power, detrimental investment and risks. The analysis argues for restricting market-based investment to controllable flow (DC or FACTS) only. This is in line with what seems to take place in practice in Europe and Australia, it strikes a balance between pros and cons of market-based investment and draws a sharp line between regulated and unregulated investments.
Keywords: electricity, transmission, merchant, investment
JEL classification: L1, L43, L94.

1. Introduction

Transmission owners, often the same as the Transmission System Operator, TSO, are typically regulated and charged to ensure reliable transmission within their network. Vertically integrated utilities have a further duty to deliver power at least cost, and can recover the cost of so doing through energy and transmission charges. Regulation may distort these choices, and lead to either excessive (Averch-Johnson effects) or sub-optimal (particularly in the presence of environmental or planning restrictions) transmission investment relative to generation capacity. Nevertheless, there is a presumption that transmission investment within the region controlled by the TSO is constrained efficient (where the constraint is the efficiency of the regulatory environment). There is no such guarantee for interconnections *between* networks under different TSOs, and there is a presumption of under-investment, as it will be difficult to persuade each network regulator to pass through those costs that benefit out-of-area users. As a result there is a presumption that some (and perhaps considerable) further investment in interconnectors (defined as links connecting different networks) is likely to be socially profitable.

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There are several possible solutions to this under-investment problem. One rather drastic solution is to require networks to be aggregated into larger regional groupings (Regional Transmission Organisations), and devolve investment planning to these RTOs. That might work within a federal country like the US, but would be problematic on the Continent. The second is to develop methodologies to reward TSOs for the services their network provides to out-of-area users, so that they (or their network users, as a result of reduced network charges) enjoy the benefits of improving interconnection. The final solution is to allow merchant investors to interconnect different networks, and to receive the network (or connection node) price differences: market-based transmission investment. While for instance Australia and the USA already have some experience of this, and projects are being planned in Europe, the policy discussion is far from settled. [2]

The focus of the paper is on Europe and Australia (in contrast to the USA). Increasingly the regions in the USA rely on *nodal* (spot) pricing to congestion manage on the network; in Europe and Australia the predominant method is *zonal* pricing. A region in the USA, for instance New York or PJM, contains a large number of differently priced nodes. In Europe and Australia, different regions (zones) contain only one price: single-price zones (for instance the APX in Amsterdam for the Netherlands). The rewards for merchant transmission investment in the USA rely on what is called point-to-point incremental financial transmission rights (FTRs), which capture network effects by taking price effects on all relevant nodes into account.[3] By definition, the zonal approach cannot capture these network effects by means of prices and cannot facilitate market-based investment within a zone. The European and Australian zonal approaches are therefore restricted to the interconnection between different systems (i.e. single-price zones). Consequently, the focus of the paper is on interconnection *between* different systems as opposed to investment within a system. It also follows that the analysis focuses on network expansion (i.e. interconnection) in contrast to network deepening or reliability investment. It follows moreover that the analysis focuses on large-scale bulky investment in new lines, rather than small-scale network upgrades.

Whereas market-based transmission investment may mitigate the problem of under-investment, it is unlikely to suffice alone and thus regulated projects by the designated transmission system operator (TSO) remain necessary. The inevitable mix of regulated and unregulated systems requires a sharp distinction. For the European and Australian context as

[2] In Australia the policy package is known under the header "safe harbours" [e.g. ACCC, 2001]. For the USA it is set out in SMD Notice of proposed rulemaking 2002, p. 66, FERC, Docket No. RM01-12-000. In Europe the policy is laid out in the European Commission's [EC, 2003] *Regulation on conditions for access to the network for cross-border exchanges in electricity* of June 26, 2003.

[3] It should be noted, however, that new problems arise (see especially section 4.3)

set out above, this paper will explore the prospects of restricting market-based transmission investment to controllable flow, defined as direct current (DC) and flexible alternating current transmission systems (FACTS). Controllable means that the flow on a line can be controlled explicitly, rather than being determined implicitly by Kirchhof's laws as in a meshed alternating current (AC) system; as a result, the loopflow effects are substantially reduced.[4] There are two reasons for drawing this line. First, the distinction between controllable versus non-controllable flow is sharp and workable. Second, the inefficiencies of market-driven decentralized investment in controllable-flow lines are far less than in meshed AC networks and may well be offset by the advantages of merchant projects.

Section 2 discusses the background and the literature, while section 3 summarizes the principles underlying market-based transmission investment. Section 4 is the core of the paper and discusses four main areas of problems with market-based transmission investment and their relative severity for controllable versus non-controllable flow. It will be argued that for systems which rely on zonal congestion pricing transmission investment in controllable flow may be market based, whilst rights to invest in non-controllable flow should be allocated only to the designated transmission system operator. The distinction between controllable and non-controllable flow appears in practice and it is, for instance, a requirement in EU legislation [EC, 2003, art. 7][5] and is part of the Australian "safe harbours" [cf. ACCC, 2001, pp.126 ff.]. Section 5 concludes.

2. Background

The critical step of market-based transmission investment is that investment in the transmission grid is no longer the exclusive and statutory right of the designated (and as a rule, regulated) transmission system operator (TSO). For the European and Australian situation, market-based transmission investment can be defined as transmission investment "operating between two connection points assigned to different regional reference nodes, [..] supported by the revenue stream generated by trading electricity between the two interconnected regions, [and] not eligible to earn regulated revenue." [ACCC, 2001, p. 126]. The payment according to the price difference between the two ends of the line is also called link-based and applies in particular to interconnectors.

Why allow unregulated third-party transmission investors in the first place? After all, transmission is considered to be the domain of monopolies where regulated, designated

[4] Loopflows are explained in section 3. For a technical analysis of controllable flow, the interested reader may be referred to for instance Gyugi [1999] and Arrillaga [1998].

[5] Art. 7 basically restricts merchant investment to DC lines but allows exceptions for stand -alone AC lines if the costs of DC lines would be very high relative to AC.

operators are dominant. Apart from the well-known virtues of market forces, three specific reasons are convincing. First, vertically integrated (generator and transmission) incumbents may have poor incentives to invest in interconnectors. Transmission constraints tend to isolate parts of the networks and thereby increase generation market power within the isolated area.[6] Vertical integration still forms an obstacle to a competitive playing field in parts of the USA [cf. Joskow, 2003, p. 13] and Europe [EC, 2002]. The second reason, which is actually more general than transmission investment, follows from a regulatory problem with risky significant new investment. The problem has been extensively discussed in Australia [cf. Gans & King, 2003]. Suppose that the investment has to be made under uncertainty about the ex-post state of the world which is either good or bad. Suppose that the rate of return of the risky investment in case of a bad state of the world is 6%, while 14% if good. If both states have equal probability the risk-equivalent expected return thus is 10%. The argument is that a regulator will do nothing if the state of the world is bad, while the regulator will be tempted to strengthen rate regulation if the world turns out to be good. Assume that the regulator may ex post reduce the rate of return in the good state to 10%. Anticipating this, the expected rate of return is 8% rather than the required 10%. It is straightforward to see that this may lead to underinvestment or abandoning the project. The underlying argument is that a regulator cannot credibly commit to refrain from intervening ex post in the good state if the line is subject to regulation. It is argued that credibility to refrain from intervening is increased by not regulating the new investment at all (for a predetermined number of years): a "regulation holiday".[7] A third reason relies on a public-choice argument. Interconnecting a low priced area with a high priced area will normally imply that the electricity price in the low priced area increases, meaning the consumers in this area actually lose form the new line. If authorities of both sides of the new line have to give permission for the new line, the authorities on the losing side may hesitate to agree. This problem may be mitigated if permission (on economic grounds) is not required, which would be the case under market-based investment.

The literature on merchant transmission investment is divided. Littlechild [2003] points to the drawbacks of regulation and expresses quite strong sympathy for market-based investment, relying on Australian experience with the regulatory alternative. The point is illustrative. Murraylink was a genuine unregulated market-based transmission investor interconnecting

[6] As a result, a vertically integrated firm faces a trade off: increased interconnector capacity enhances trading opportunities but also increases competition from other areas. Which effect dominates is an empirical matter.

[7] The argument raises discussion as to when regulatory uncertainty (or -threat) is stronger: existing regulation which could be strengthened or non-existing regulation which should be installed. Experience with regulatory threat in New Zealand suggests that the step to install regulation is large and time-consuming, implying that uncertainty might be relatively low. For more on New Zealand, the interested may be referred to Brunekreeft [2003, ch. 10].

Victoria and South Australia (SA). While Murraylink was being constructed, another project called SNI requested access to the regulated connection charges and passed the regulatory test in December 2001. A project only passes the regulatory test if maximizes net social benefits with regard to a number of alternatives. SNI connects New South Wales (NSW) and South Australia (SA), which is largely parallel to Murraylink.[8] In the regulatory test two options were considered. First, the bundled SNI, building the line plus some upgrading (especially of the grid) in NSW. Second, the unbundled SNI which meant only upgrading especially the NSW grid, without building the line itself. Cost-benefit analysis revealed that the unbundled SNI had a substantially higher value to society. Nevertheless, the bundled SNI was approved, based on the argument that, faced with risk of stranded assets the unbundled SNI was not commercially feasible: upgrading the grid without building the line would leave the investment exposed to the market power of Murraylink. Without commercial feasibility, the unbundled SNI could not be considered to be a realistic alternative and thus the bundled SNI was approved instead [cf. also Kahn, 2002, p. 13 and NEMMCO, 2001, pp. 13, 14]. The arguments in the case centred around the question of the degree of market power of Murraylink with respect to the assets of unbundled SNI. As a result of the permission to build the bundled SNI, Murraylink expected its unregulated line-based revenues to fall and requested for conversion to a regulated operator, which was recently approved. The case has been controversial and leads Littlechild [2003, p. 28] to conclude that: "an implication of the Australian experience to date is that there may be more danger of excessive than thwarted regulatory investment. Even with reform, merchant transmission could remain vulnerable." Although dependent on this distinction, the case illustrates how regulated projects can crowd out unregulated projects.

On much the same line as Littlechild [2003], Hogan [2003] argues in favour of merchant transmission investment, although with some reservations,. More precisely, Hogan advocates drawing a clear line between regulated and merchant investment, to avoid the 'slippery slope' that the regulated options crowd out the merchant options. Hogan's [2003, pp. 22/23] approach is that: "regulated transmission investment would be limited to those cases where the investment is inherently large relative to the size of the relevant market and inherently lumpy in a sense that the only reasonable implementation would be a single project like a tunnel under a river. [..] Everything else would be left to the market." 'Large' basically is defined as commercially unprofitable.[9] The decision rule might thus be that a regulated

[8] The connection points for SNI in NSW and Murraylink in Victoria are close.

[9] "Further, 'large' would be defined as large enough to have such an impact on market prices that the ex post value of incremental FTRs and other explicit transmission products could not justify the investment." [Hogan, 2003, p. 23]. Regulated here means that the revenues comes from a pool of regulated connection charges. Details will be clarified further below.

project is socially beneficial but not commercially feasible: in that case, the costs of line would partly be financed form the pool of regulated network connection charges. If as Hogan [2003, p. 23] suggest "someone" defines the criteria and executes evaluations to determine large and lumpy projects, an element of arbitrariness seems inevitable. Alternatively, if the rule is not specified, the line between merchant and regulated remains blurred.

Joskow & Tirole [2003] are more critical of the prospects of market-based transmission investment and forcefully point out a number of problems. A first argument is lumpiness in transmission investment, which implies that rewards based on marginal prices lead to underinvestment [Joskow & Tirole, 2003, p. 21 ff.]. This type of argument is basically in the same group as economies of scale as discussed in section 4 below. Further, generation market power at one end of the line will distort the prices and thereby the line investment decision [Joskow & Tirole, 2003, p. 17 ff.]. This may lead to over- or underinvestment depending on the node with market power. A quite special problem is what Joskow & Tirole [2003, p. 25] call "state-contingent rights and diversification"; the problem relies on the difficulty to determine the line capacity (as an operational capacity), which depends on the flows in the connecting networks, which in turn depends on, for instance, demand. If usage of the line is sold off by long-term rights, then it is not clear what is to be sold if capacity is not determined. The theoretical answer is to sell state-contingent rights, which however are not well developed as yet. As the authors [2003, p. 25] note, this problem is typical for AC meshed networks.

Another set of problems rely on a governance problem associated with the split between the transmission owner (TO) and system operator (SO) which is inherently related to merchant investment. The problem is who gets paid for what. The details are beyond the scope of this paper, but it seems that as above the problem is less severe in the DC case because the flow and thereby the "output quantity" can be controlled by the line owner. A problem which receives in-depth attention in Joskow & Tirole [2003, pp. 39 ff.] is the problem that the new line may be detrimental to the system (due to loopflow effects). The problem has been discussed in for instance Bushnell & Stoft [1996c] and will receive detailed attention in section 4.3 below. A last point to be mentioned is regulatory risk [Joskow & Tirole, 2003, p. 57]. It is suggested that regulatory uncertainty may make funding of the merchant projects infeasible. Whereas this is a strong argument, it should be noted that regulatory uncertainty was at least in Australia the predominant reason to grant regulation holidays and rely on unregulated merchants in the first place. In all, Joskow & Tirole point out a set of possible inefficiencies, which overall appear to be severe for network-deepening investments in meshed AC networks, whereas the arguments lose part of their strength for interconnection DC lines, as will be argued below.

The difficulty identified in these papers is the regulatory mix of the unavoidable co-existence of regulated and unregulated lines. The difficulty is to find a stable and workable borderline where crowding out of commercially viable projects by regulated projects (or reverse) is unlikely. Especially for zonal systems like Europe and Australia, merchant investment may be restricted to DC interconnectors between different systems whereas AC projects may be reserved for designated TSOs or authorised tenders. This would at least draw a sharp line.

3. Locational marginal pricing, line rentals and investment

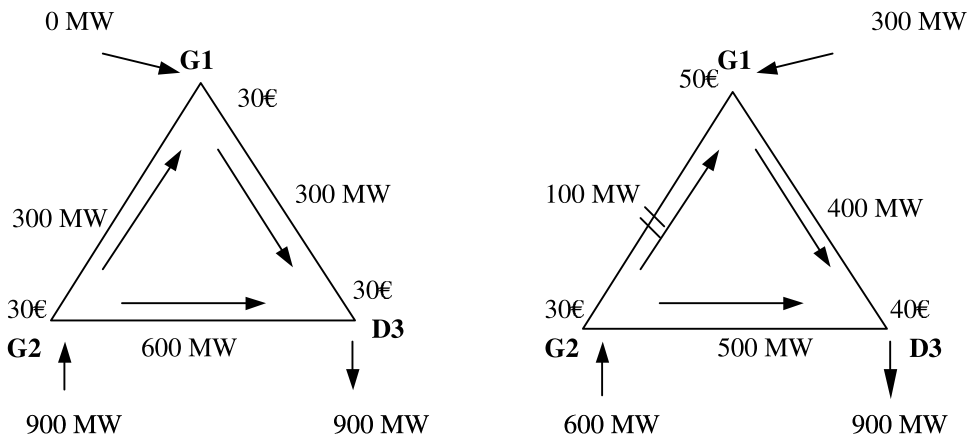
The principle underlying merchant investment is called locational marginal pricing (LMP), or nodal spot pricing, which was developed for congestion management by Bohn, Caramanis & Schweppe [1984] and was worked out and applied in New Zealand [cf. Read & Sell, 1989; and Read, 1989]. An important formalisation and modification came with the contribution of Hogan [1992], who extended the basic model by a set of financial hedges, so-called Financial Transmission Right (FTRs).[10] Meanwhile, the LMP-FTR approach has been (or will soon be) implemented in some variation in several states in the USA (e.g. PJM, New York, New England, Texas and California) and is a cornerstone of FERC's currently debated Standard Market Design. Europe and Australia do not have nodal spot pricing but at best zonal pricing. Basically this means that for an area like, for instance, the Netherlands there is only one spot price and the network is not further differentiated (as if the network is unconstrained). Nodal spot pricing would define a set of different nodes within the Dutch network, which, depending on congestion within the network, might have different prices. In the nodal pricing scheme a new line connects two different nodes (quite possibly within one network), whereas in Europe and Australia a new line is more likely to interconnect different networks and trade between the associated zonal prices. As a result, the European and Australian interconnectors can roughly be considered as two-node interconnectors.

The basic idea is straightforward. Consider a two-node network with a transmission line between the two nodes. Suppose that at each node a spot price reflects the marginal costs of electricity at that node at that moment. As long as the spot prices at the two nodes differ, then the difference must reflect the opportunity costs of transmission, otherwise traders buy power at the cheap node and sell at the expensive node until the price differential is zero. The opportunity transmission costs to be reflected rely on energy losses and congestion (also

[10] Also known as Congestion Revenue Rights.

called, constraints), which can be seen as the limiting case of energy losses.[11] If the load increases up to the line's capacity the line will be congested. At that point the TSO will have to secure a dispatch such that the load on this particular line is not further increased. In other words, congestion in the lines affects the dispatch of the generation units, such that a price differential between the nodes remains.

Some situations in electricity networks can usefully be represented by a two-node network. Typically, however, an electricity network consists of many different interconnected nodes, creating a meshed network. A network with alternating current (AC) creates so-called loopflows. Electric power in an AC-network follows Kirchhof's law, meaning that a power flow divides itself over the network proportional the inverse of the line impedances.[12] The idea is illustrated in figures 1a and 1b. In these figures, representing a three-node network, nodes G1 and G2 are generation nodes and node D3 is a load node. Line L_{ij} is the line between nodes i and j. The three lines are assumed to have the same physical impedance and are equally long. Hence the route from node 2 to node 3 over L_{12} and L_{13} is twice as long as over L_{23}, and thus the impedance on the short route is half the impedance of the long route.



Figures 1a and 1b: Loopflows in a three -node AC network.

In figure 1a, it is assumed that there are no line constraints and the load of 900 MW is completely generated by G2. The power flows according to the inverse of the line impedances and thus 600 MW flows over L_{23} and 300 MW over L_{12} and then L_{13}. In figure 1b it is

[11] The reader may note the equivalence with congestion charging in road pricing as developed by Mohring & Harwitz [1962]. Since energy losses are a squared function of the line load, the optimal transmission charge is twice the energy loss. If the system-dispatcher (TSO) minimizes the production costs (given demand), then the nodal prices will exactly reflect this. Half of the revenues from the transmission charges would cover energy losses (which are real costs) and the other half is a surplus, similar to the Pigouvian tax.

[12] In technical terms, the impedance is the "sum" of the line's resistance and reactance.

assumed that the dispatch is 600 MW from G2 and 300 MW from G1. The 600 MW from G2 divides 400 MW on line L_{23} and 200 MW on L_{12} and then L_{13}. The 300 MW from G1 flows 200 MW over L_{13} and 100 MW over L_{12} and then L_{23}. In total thus, the flow over L_{23} is 500 MW, L_{13} is 400 MW and L_{12} 100 MW. The flow on L_{12} is determined by subtracting the opposing flows: 200 MW - 100 MW is 100 MW. The dispatch in figure 1b may be the resulting dispatch if the lines are constrained. Suppose that G2 has lower production costs than G1 such that the dispatch in figure 1a would be the desired dispatch. If the capacity of L_{12} is constrained to 100 MW then the dispatch of figure 1b would be the constrained optimum. The unconstrained dispatch of figure 1a would not be feasible, because L_{12} cannot handle 300 MW.[13]

Figure 1b also depicts nodal spot prices. The spot prices at the generation nodes are derived from the marginal production costs at these nodes (for this dispatch), which is straightforward.[14] The price at the demand node is derived as the marginal production costs of one additional demand unit. In this case, 1 MW additional demand would (have to) be produced 0.5 MW from each generation node. (0.5 · 30 €) + (0.5 · 50€) makes 40€. And so a complete set of nodal spot prices can be calculated. The transmission charges (denoted by t_{ij}) immediately follow: t_{21} = 20€, t_{23} = 10€, and t_{13} = -10€. Multiplying with the flows on the subsequent lines gives a surplus of 3000€. Note that the transmission charge on L_{13} is actually negative because the flow is from a high price node to a low priced nodes. [15]

In an LMP system spot prices are volatile and the spot price on one node depends implicitly on all other nodes in the network. In other words, an LMP system involves (short and long term) risk for the users. Financial Transmission Right (FTRs) have been developed to hedge these risks. An FTR is defined as a contract between any two nodes i and j with a strike quantity R_{ij} paying out to the owner of the FTR the difference between the nodal spot prices p_j and p_i times the strike quantity R_{ij}. Hence, the payment of an FTR can be denoted by $T_{ij} = R_{ij} \cdot (p_j - p_i)$. It is important to note that the definition of an FTR is not restricted to the two ends of a line; an FTR is defined between any two nodes and makes no reference to a line. The TSO, being the collector of the transmission charges, may be the counterparty and the FTRs

[13] Note that for instance G1 = G2 = 450 MW would also be feasible, but not (constrained) optimal. Production costs would be higher than under G1 = 300 MW and G2 = 600 MW per assumption. In case G1 = G2 = 450 MW the power flow on L_{12} = 0.

[14] Note that the cost functions are not given here.

[15] In this interpretation, the transmission charge is actually paid by the owner of a trading contract between nodes i and j. Another way to think of transmission charges is that load pays 40€ at node 3 and the G1 receives 50€ at node 1 and G2 receives 30€ at node 1. Multiplied by subsequent quantities gives a surplus of 3000€.

may be allocated by an auction.[16] Suppose that a trader trading quantity q_{ij} to prices p_i and p_j actually pays the transmission charges $q_{ij} \cdot (p_j - p_i)$ to the TSO and hedges this risk with the contract $R_{ij} \cdot (p_j - p_i)$. It can then quickly be seen that if the strike quantity R_{ij} approximately matches the real quantity q_{ij}, and given that initial payment for the FTR as such, the price differences cancel out and the risk is hedged.

The LMP concept proves controversial [cf. Wu et. al., 1996 and Oren et. al., 1995]. This debate produced the following important result of Chao & Peck [1996], who contrast the LMP-FTR approach of financial transmission rights with a *flowgate* approach, which relies on physical transmission rights. In the LMP approach the "transmission rights" follow from the dispatch, while the FTRs are merely financial instruments and do not provide physical transmission rights. In contrast, physical transmission rights would be allocated prior to production and hence dispatch follows transmission rights rather than reverse (at least, the dispatch should take the transmission rights into account as binding constraints). The flowgate approach applies powerflow distribution factors (PDFs) to calculate which nodes claim how much from the capacity of which line, for congested lines only. Chao & Peck [1996] show that under certain conditions the flowgate model gives the same results as the LMP approach. This useful result allows one to restrict attention here to the LMP analysis; with caution the analysis below may thus be carried over to a flowgate approach and thereby to interconnectors in a European and Australian context.

A system of spot prices, be it as refined as a nodal LMP system or as crude as two different zones, implicitly defines a pricing rule according to which investment in interconnector capacity can be paid: the price differential between different nodes. This can be interpreted as a high-level regulatory rule: the rule-maker has decided that market-based line investment will be paid according to this rule. That is what the definition of the ACCC states explicitly. Section 4 will now explore the problems which may arise with unregulated market-based investment paid by the price differentials.

4. Problems and prospects of market-driven investment

This section discusses four main areas of potential inefficiencies associated with market based transmission investment in the context of controllable and non-controllable flows. The four areas are: economies of scale and cost-recovery, market power and the size of capacity, detrimental investment and risk.

[16] There are variations. For a combination with Contracts for Differences, see Bushnell & Stoft [1996b]. The allocation of the revenues of the auction (or in other words, line rentals) is again a different issue. It seems natural to allocate the revenue to the line owner as a contribution to the line's costs. This issue appears to be rather controversial. See for instance Read [2002] for the discussion in New Zealand.

4.1 Economies of scale and cost recovery

Economies of scale in the construction of transmission lines are substantial. Footnote 11 pointed to the similarity with the theory on road congestion charging as in Mohring & Harwitz [1962]. The long-run effects are well known from this literature and are directly applicable here. The congestion charge is a surplus over energy losses which can contribute the fixed costs of the infrastructure. The surplus depends on demand relative to capacity. In the long run in which capacity is variable the following result holds: if long-run marginal costs (i.e. capacity expansion costs) are decreasing in capacity, the surplus resulting for optimal capacity will be less than the fixed costs. Hence with economies of scale in the construction of new transmission lines, the transmission charges relying on the price differentials will not entirely recover fixed costs with optimal capacity size. As a result we can conclude that either market-based transmission investment is not profitable (in which case it will not take place) or capacity is smaller than optimal.

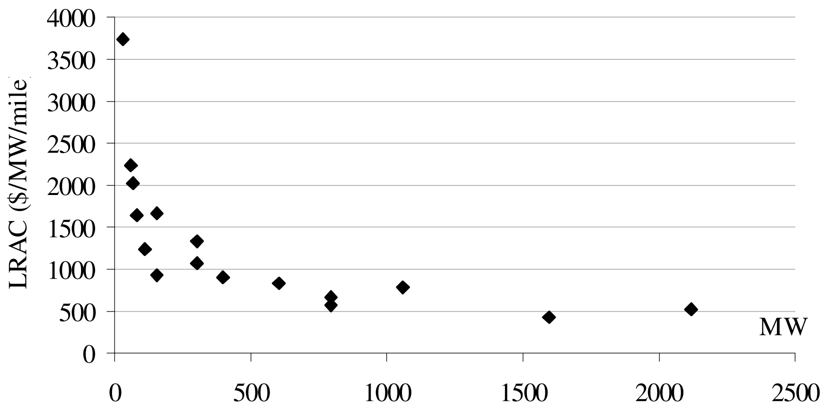


Figure 2: Economies of scale in transmission infrastructure
Source: based upon Fuldner, 1998, table FE2.

Figure 2 indicates the relevance of economies of scale based on real construction costs [cf. Fuldner, 1998].[17] Figure 2 plots average construction costs (US$ per MW per mile) in relation to the line's capacity, as the least-cost envelope of different technologies. Similar indications come from for example Read [2002] and Perez-Arriaga et. al. [1995], suggesting that not more than 30% of total costs could be recovered by LMP differentials if capacity is optimal. It appears that DC interconnectors are used for bulk power transactions. As a result the scale economies may be exhausted at some point; figure 2 suggests that beyond 750 MW long-run

[17] These are line construction costs only and exclude AC/DC converters. Investment costs may include right-of-way charges, which may be high. If these are high and charged per capacity unit they may dominate the construction costs and may cause capacity expansion costs to have constant or even decreasing scale effects.

marginal costs are near constant. The extent of economies of scale depends on the fixed costs of the optimal technology relative to the size of the market, but typically economies of scale get less if the size of the market grows. Hence one would expect economies of scale for DC interconnection of different networks which primarily aims at transmission of bulk power to be less than small-scale AC network deepening projects; even if these AC projetcs are small scale, they may be large compared to the size of their market. The DC-interconnector projects in the USA are typically around 1000 MW, which is also the order of magnitude for European projects (for instance, UK-Norway or UK-NL interconnectors). The interconnectors in Australia are considerably smaller, with capacities around 200 MW.

A first approach to the problem is second-best pricing. Imagine that an implicit tender (where some body such as a regulator, chooses between different alternatives) determines the line owner. With competitive bidding, the result would be a second-best capacity of the line where the line rentals would exactly recover costs with mark-ups on marginal costs. With relatively inelastic demand, the deviation from the optimum caused by the mark-ups on the marginal costs may actually be rather small. The relative deviation from the first-best solution gets smaller the larger the line. This argument is appealing but can be criticized on two accounts. First, a second-best solution would be inferior if a first-best solution with two-part pricing is feasible; theoretically, the first-best solution with two-part pricing (congestion plus connection charges) can be achieved by the designated and regulated TSO and hence there is a trade-off involved. Second, an implicit auction for the right to build the line is not entirely compatible with a decentralized scenario.

A second way to proceed is user-specific two-part pricing, although this is not as obvious as it might seem. Apart from an LMP based variable charge a fixed use-of-system charge may contribute to the remaining costs. It is in principle possible, but cumbersome and theoretically weak. The idea is to develop an algorithm which allocates the costs of the line in some relation to the usage of the line, for which two methods are used: the area-of-influence method (also called marginal participation) and tracing (also called average participation).[18] Tracing has the economic advantage of relying on the Shapley value [Kattuman et.al., 2003]. The allocation of the cost of the line is irrelevant for the sunk costs of existing lines, but is important for cost-recovery of new lines and hence is important for investment decisions. Roughly speaking, the more meshed the network is, the more difficult it gets to identify users in an economically useful way. Concluding, user-specific allocation of the (fixed) costs of a

[18] It is beyond the scope of this paper to go into detail and instead the reader may consult Vazquez et.al. [2002] and Kattuman et.al. [2003]. The method of area of influence is applied in Argentina where it works reasonably well, because of the radial network into Buenos Aires [cf. Woolf, 2003, p. 265].

(new) line can be done, although not without difficulty, and thus user-specific charging is possible.

Nevertheless, the argument has a theoretical flaw. Demand for the interconnector is derived demand from the arbitrage possibilities between the interconnected spot markets. Assume for the sake of the argument that the users of the line are traders who arbitrage between two spot markets. The traders generate revenues by buying "kWhs" at the cheap node and selling at the expensive node; in other words, their revenue is expressed in variable terms (per kWh). The underlying cost structure for using the transmission line will be passed through (if at all) as a variable charge by the traders. As long as the traders' revenues with which the line should be paid are variable, the final result will always be second best. Stronger even, if competition among the traders is fierce, they would compete each other down to variable costs and would not be able to recover the fixed charge. The problem of under-recovery of the costs would simply be passed on. If this is the result then the line itself might have been charged with a uniform mark-up in the first place.

A third aspect to be considered is whether all costs and benefits are in fact included in the LMP-based line revenues and hence whether they are internalised in the investment decision. Three issues are relevant. First, new lines will in general have an impact on the reliability of the system. A new line may increase reliability in the network by increasing capacity in which case the TSO might compensate the line owner. Moreover, controllable flow lines increase the system's transfer capability and add to the system's stability by being controllable [cf. Gyugi, 1999, p. 31; and Arrillaga, 1998, p. 8]. On the other hand, especially in the face of loopflows the new line might decrease reliability and even require upgrading the network. In that case, the line should be charged a deep connection charge for the costs of upgrading. Second, the line owner might paid a capacity payment. In for instance PJM, the authorities have created a market for generation capacity in which capacity contracts are traded. The capacity prices differ according to relative scarcity between different areas. A new line connecting two areas with different capacity prices can arbitrage the capacity price difference. Line revenues would then consist of energy price differences and capacity price differences. Third, environmental effects should be taken into account. New transmission lines will in general have an environmental cost, but these costs may be less than the alternatives. For instance, subsea and underground cables are perceived as far less environmentally damaging than overground cables.

4.2 Market power and size of capacity

Profit-driven investors will have an incentive to maximize profits rather than welfare. New transmission capacity between two nodes will usually lower the price difference between the two nodes and hence lower the line rentals. In analogy with normal monopoly type behaviour, investors will seek to restrict capacity below the socially optimal capacity.[19]

Apart from the direct distortion, there may be indirect effects. An important benefit of additional interconnector capacity is that it enlarges the relevant markets of the generators; in other words, depending on whether market power is on the exporting or the importing node it may mitigate market power on the generator side. Assume market power in generation at the import node. The direct effect is that additional capacity is the same as an additional competitor (say, Cournot-like competition with more firms) and the indirect effect is that increased total capacity reduces the margin between (peak) demand and total capacity and hence will decrease the probability of a pivotal firm (i.e. a change in the nature of competition). Thus a new line may increase competitiveness, but if market power induces the investor to keep capacity inefficiently small, the effect on generator competitiveness will be inefficiently small as well.

There are several ways to approach the "monopoly" problem. The straightforward approaches are either to require passing a "best option" test which compares the proposal against reasonable alternatives, or to organize a tender after the project has been identified by a commission. Ideally, both cases would result in the second-best solution which may be highly preferable to the monopoly outcome. Especially in combination with arguments put forth below this is appealling but has the drawback that it inevitably reintroduces an element of centralized decision making.

An alternative approach might take the view that the monopoly problem is primarily a problem of the AC network and less so for controllable interconnectors. In as far as "parallel" lines are feasible at all, controllable flow actually allows a competitive choice. In a non-controllable system "parallel lines" would still be "monopoly", because the parallel lines are "bundled". In a DC-system two parallel lines can actually compete in capacity, while in a non-controllable system this is technically not possible. Moreover, in a non-controllable

[19] Depending on demand and the magnitude of scale economies, the underinvestment may partly be offset by preemptive investment (similar to limit pricing). In a world with firm transmission rights the line owner may then decide not to use all capacity to restrict availability of the line. In a slightly different setting, the argument reminds of the argument put forth in Gilbert, Neuhoff & Newbery [2002] and Joskow & Tirole [2000] that a dominant importing generator has an incentive to acquire (and then restrict the use of) physical transmission rights in order to retain its market power. Restrictions on capacity withholding would relieve the problem partly, but might on the other hand have adverse effects for the level of investment.

system, the capacity of line A determines the capacity of "parallel" line B. It follows that regarding the capacity decisions, parallel controllable lines are strategic substitutes and "parallel" non-controllable lines strategic complements. From this it is then straightforward that -if at all- the competitive pressure among controllable lines will be stronger.

A related but slightly different "monopoly" problem is pre-emptive investment, meaning strategic investment to deter others. The arguments are much in line with the limit-pricing approach developed by Bain, Sylos-Labini and Modigliani.[20] If due to economies of scale and/or lumpiness entrants can only profitably enter at some minimum effcient scale, the incumbent can invest pre-emptively so as just to deter the entrant. The result is that the capacity of the investment is either the monopoly capacity or the minimum capacity which just deters entry, whichever is the lower: call this the limit capacity. The pessimistic view is that the limit capacity is less than the optimal capacity, which is correct, but it may be the wrong benchmark. The optimistic view may emphasize that, given the monopoly problem, the limit capacity is at least as big as the monopoly capacity and thus pre-emptive investment mitigates this problem.[21] In all, the argument stresses that there may be some pressure from potential new investors.

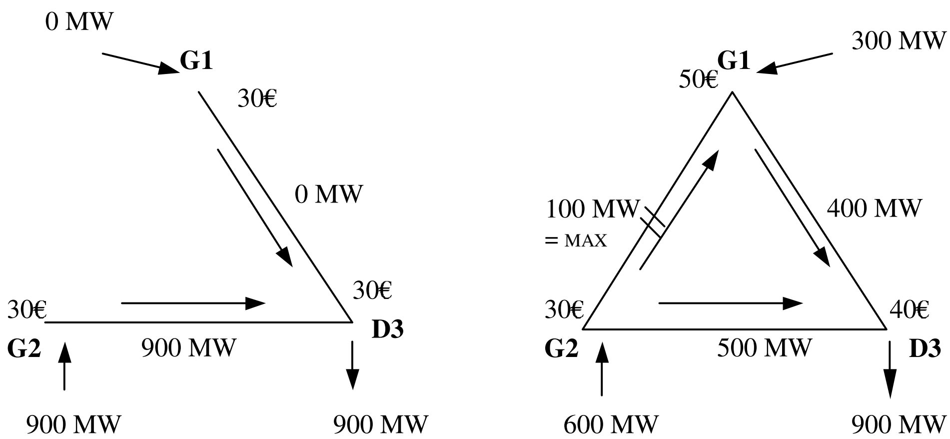
Following the line of argument on limit-pricing approaches implies that if demand is large as compared to the minimum effcient scale, a point will be reached where it is no longer profitable to deter entry. The limit capacity would have to be too large and it might actually be more profitable to accommodate new entry. There are assumptions underlying this rather theoretical result, but the main lesson seems to hold throughout. If interconnecting DC lines are typically used for bulk transaction over long distances, the size of the market may be large relative to optimal line sizes. Consequently, the required pre-emptive investment may be sufficiently large such that entry accommodation is more attractive.

4.3 "Profitable expansion can be bad"

The principle of rewarding investment according to the price difference between the two nodes which are interconnected by the new line (link-based) is flawed, because it ignores network effects. In the debate on the usefulness of LMP, Wu et. al. [1996] and Oren et. al. [1995] pointed out that under a regime with link-based LMP-FTRs, profitable market-based transmission investment can actually be detrimental to the system and hence be inefficient. Consider figures 3a and 3b, which are closely related to figures 1a and 1b.

[20] Cf. Gilbert [1989] for an excellent overview.
[21] With lumpiness, pre-emptive investment may even result in overinvestment: i.e. larger than optimal capacity.

In figure 3a, there is no transmission line between G1 and G2 and the resulting dispatch then is that G2 produces 900 MW and G1 0 MW and the power flows are straightforward. In the absence of constraints the prices are 30€ at all nodes, corresponding to marginal costs at node G2. Now assume that a merchant invests in a 100 MW line between nodes G1 and G2. The corresponding dispatch then becomes as in figure 3b, which corresponds to figure 1b. The noticeable change is that the power flows cause the new line to be constrained which then alters the dispatch such that G1 produces 300 MW at as can be seen relatively high costs. The resulting prices are as given. Assuming link-based payment, it follows immediately that the investment is profitable if the investment costs are lower than 2000€.[22] Welfare has decreased because the production costs have increased while output did not change. Hence, a bad modification can be profitable.



Figures 3a and 3b: "Bad" modification can be profitable.
Source: Bushnell & Stoft [1996b, p. 5].

The fundamental problem underlying this example is that link-based line rentals, defined as the difference between the prices at the two nodes connecting the line, do not reflect incremental network effects. Whereas the line transmission charge does reflect the opportunity costs in a two-node network, this is not so in a meshed network. The net benefits of the line investment should take account the impact elsewhere in the network (here the change in the line rentals between G1 - D3 and G2 - D3).

A powerful solution to the problem has been developed by Bushnell & Stoft in series of articles [1996a-d, 1997]; variations have been implemented in the USA and have come to be known as incremental financial transmission rights (FTRs). The crucial step is to modify the

[22] Link-based line rentals on G1-G2 are $100 \cdot (50-30) = 2000$.

investment reward system such that new investment is rewarded by a "must-accept" set of FTRs, which in essence captures the incremental external effects of the new investment over and above the direct rewards of the invested line. It is important to realize that the FTR pays $\Delta R_{ij}\cdot (p_j - p_i)$ to its owner; in the proposal, the merchant line investor is the owner. As above, p_i is the spot price at node i. ΔR_{ij} is the FTR strike quantity of line ij, representing the difference between the dispatched flow after and before the line investment. Note that the value of a so-defined FTR can be negative. The investor would have to accept the set of so-defined FTRs for all affected lines. Bushnell & Stoft [1996c, p. 73] show that if the consolidated set of contracts match the current dispatch "then no group of agents whose contracts match their dispatch will find it profitable to make detrimental alterations to the grid."[23]

The key modification is to capture the incremental network effects, which implies the step from link-based line rentals to network rentals on the one hand, and payment according to increments of flows (ΔR_{ij}) rather than total flows (R_{ij}) on the other. As a result, the impact of the new line on the "entire" system is captured. In the example above, the new set of FTRs would be: $\Delta R_{12} = -100\cdot (30-50) = +2000$, $\Delta R_{13} = +400\cdot (40-50) = -4000$, and $\Delta R_{23} = -400\cdot (40-30) = -4000$, which in total sums to -6000.[24]

The system is not without drawbacks. First, the system is path-dependent. It relies on *changes* in flows and thus always compares with the current situation. Since payment and thereby incentives for new investment rely on the current network, inefficiencies in the current network are likely to carry over. A second problem has been pointed out by Bushnell and Stoft [1996c, p. 77]. The requirements of matching of contracted and actual flows are extremely unlikely to be met. A third problem is more fundamental. This type of reward for the investment requires assessment of both the old and the new dispatch which is controversial. A central institution will have to decide on the external incremental power flows as the basis for the must-accept contracts. Hence, whether or not the investment will be profitable depends to a large extent on a discretionary decision making power of a commission. This may be unavoidable but principally contradicts the idea of decentralized, unregulated merchant. The point has been well put by Joskow & Tirole [2003, p. 42, italics in original]: "It should be clear as well that in practice the merchant transmission model cannot operate "as if by an invisible hand", since some *de facto* regulatory authority must have the ability accurately to simulate load flows on the network, apply contingency criteria, define feasible sets and changes in feasible sets associated with transmission investments, and ensure that rights allocations are consistent with feasibility under numerous contingencies."

[23] Unclear is whether this is the same as "efficient investment".

[24] Note that the link-based LMP-FTR based price is part of the bigger scheme.

Alternatively one could approach the problem with deep connection charges/payments to interconnectors. These are designed to reflect the costs and benefits resulting from the new investment, and accruing over the system as a whole. These can be calculated on a case-by-case basis or a proxy might be developed. In a link-based system, the effects pointed out above would have to be included in the deep connection charges. The problem is that if the external effects are substantial (relative to the revenues of the link-based price differentials), a significant proportion of costs and benefits are effectively not market based, but determined by a centralized institution.

The network effects are typical for AC networks, whereas the problem rapidly loses relevance with controllable DC lines. Consider the example in figure 3. The "bad" modification as exemplified in figure 3b is caused by the loopflow problem. Kirchhof's laws dictate that the power flow on R_{23} is less than 900, because of the proportional split and the line constraint on R_{12}. This no longer holds if the new line R_{12} is a controllable flow. If in the example in figure 3b the flows are controllable, the new line simply would not be used (i.e. the flow would be set at zero) and the dispatch could be as in figure 3a. It is thus unlikely that the line would be built in the first place. As a result, controllable technology reduces the network effects and strengthens the relation between link-based LMP based profitability and welfare effects.[25]

This problem sets the main difference between the nodal-pricing approach in the USA and zonal pricing in Europe and Australia: the system of incremental FTRs relies on the existence of nodal spot prices. Consequently, in Europe and Australia it cannot be implemented. Thus with incremental FTRs the scope for AC based network investments in the USA is larger than in link-based systems as in Europe and Australia, essentially because the network effects are not captured. It follows that in the zonal approach in Europe and Australia it would seem to be good policy to restrict merchant investment to DC interconnectors.

4.4 Risk

The last problem with market-driven transmission investment to be put forth here relies on high risks caused by monetary spill-over effects.[26] The precise extent and nature of the spill-overs depends on how exactly the line investor is rewarded, but the result always is that revenue is uncertain. Within an LMP based scenario it appears quite difficult to find a perfect

[25] The argument has larger application than merely part of a meshed network if the three nodes are considered to be for instance France, UK and Benelux and the interconnectors are AC or DC lines.
[26] It must be emphasized that these should be distinguished from real external effects.

hedge. It follows that market-based transmission investment may be quite risky which will tend to suppress investment levels.

Suppose first that the line owner is paid according to link-based LMP line rentals. The profits would be:

$$\pi_{ij} = q_{ij} \cdot (p_j - p_i) - K$$

where q_{ij} denotes the real flow in the line ij, p_i and p_j are the spot prices at nodes i and j and K is the investment cost. In this setting the investor is extremely vulnerable to investments elsewhere in the network. Not only the spot prices may vary beyond its control, but due to loopflows, the quantity may also be variable, which is well illustrated by figures 3a and 3b. Importantly, once invested the returns are largely beyond control of the investor, which, given the interactions of meshed networks, makes it rather hazardous.

Second, suppose that the line owner sells off FTRs to network users over and above the line rentals. Denote A as the (auction) revenue of the sold FTRs. The investor's profit is:

$$\pi_{ij} = q_{ij} \cdot (p_j - p_i) - R_{ij} \cdot (p_j - p_i) - K + A$$

If the real flows (q_{ij}) and the FTR's strike quantity (R_{ij}) match, the investor is insulated against changes in the spot prices. However, the investor is vulnerable against the quantity effect: any new investment (or demand) will affect the real power flows. It quickly follows that profit decreases if q_{ij} decreases. As above, with non-controllable flow the power flows are largely beyond the control of the line owner and thus despite hedging, considerable risks remain.

Third, suppose that the line investor is rewarded with FTRs (as opposed to line rentals). The investor's profit then is as follows:

$$\pi_{ij} = R_{ij} \cdot (p_j - p_i) - K$$

The investor is insulated against quantity risk. Instead, it is now vulnerable to the spot prices. If the differential decreases, profit decreases. This is likely to happen, if for instance a new power plant is built in the vicinity of the high priced node.[27] It may be recalled that high nodal spot prices signals new investment opportunities and that risks involved in the third scenario readily translate to the Bushnell & Stoft network-based payment as characterized above.

A fourth option allocates FTRs to the line owner, who then auctions off the FTRs to the users. Both the congestion charges as well as payment to the FTR owners are taken care off by the system operator and beyond the line owner. The line owner's profit would be:

[27] In fact, Directlink, one of the merchant projects in Australia (connecting Queensland and New South Wales), faced this problem.

$$\pi_{ij} = A - K$$

The ex-post risks would be shifted completely to the users. The line owner would only have the ex-ante risk of the auction revenue, which depends on the definition of the FTRs. Moreover the FTRs prices derived from the auctions presumably reflect a risk premium, which in turn depends on the level of uncertainty.

The examples illustrate that the risk (-allocation) depends on the type of reward, which in turn depends on the institutions. The effect of the risk will be to require a high risk premium and hence to increase cost of capital, or make isolated projects unprofitable altogether. Whether the risks are prohibitively high or manageable is an empirical matter. Overall the difference between controllable and non-controllable seems decisive. The loopflows in the non-controllable system make the actual (future) flows rather difficult to predict; the risks are amplified by loopflows. In contrast, the quantity in the controllable line can be determined by the owner which reduces the problem.

5. Concluding remarks

Notwithstanding drawbacks, market-based transmission investment may well have sufficient advantages to support close examination. First, the (monopolized and regulated) alternatives do have well-known drawbacks as well, among which under-investment. Second, market-based transmission investment takes place in practice. Third, legislators and regulators are developing regulatory frameworks to approach the situation [cf. e.g. Newbery, Von der Fehr & Van Damme, 2003]. Whether these are permanent developments is as yet an open question, but they do justify attention.

This paper focuses on the institutions in Europe and Australia and thereby on interconnectors between different systems. Europe and Australia rely on *zonal* pricing in contrast to the USA where *nodal* pricing is settling. It is argued that new high-voltage direct-current (HVDC) interconnectors can well be market based. The investment would be financed by trading on the price difference between the two ends of the line; reliability effects on both ends of the line would have to be taken into account separately. Especially in the European and Australian zonal approach, merchant alternating current (AC) investment appears problematic and it should better be reserved for the designated transmission system operators.

Four main problem areas of market-based transmission investment have been examined with respect to the distinction between controllable and non-controllable flow. A first problem is economies of scale. At least theoretically the argument can be made that market-based investment will be smaller than optimal. The severity of the problem depends on the size of the line relative to the market. Typically DC lines are used to interconnect different network areas between which potential power flows can be expected to be large, reducing the severity of the problem. Furthermore, deep compensation for additional costs and benefits may increase or mitigate the problem. Associated in particular with DC interconnectors, compensation for increased reliability offers scope.

A second problem is that market-based investment may actually be a monopoly investment. The severity reduces if the market is large as compared to the lines, because at some point the market may allow competing lines. More importantly, parallel DC lines being controllable can actually be competitive. In contrast, on AC "parallel" lines, the non-controllable flows over the lines would effectively be bundled and could not compete. Hence, competitive potential between lines, if at all, requires controllable flow and will thus reduce the severity of the monopoly problem for controllable lines.

A third problem is that the LMP-based reward for new transmission investment either may be inefficient or require a modification of the rule, which inevitably is a move away from decentralized decision making. In the face of loopflows, a reward system based on the spot prices at the two ends of the line only ("link based") may well be inefficient, because impacts elsewhere in the network are not reflected in the revenues. The way out is to modify the rule by creating a set of *incremental* payments ("network based"), reflecting the impact of the line in other parts of the network. The main problem with this is that this has to be estimated by a centralized agency and is open to controversy and legal challenges; thereby, the major advantage of market-based transmission investment would vanish. A system of point-to-point incremental FTRs has been implemented in several regions in the USA to tackle this problem. This approach requires nodal spot pricing (LMPs), and thus cannot be applied in Europe and Australia, where zonal pricing is predominant. Since the problem is inherently related to loopflows and thus typical for meshed AC networks, in a zonal (link-based) system it seems to be good policy to restrict merchant investment to DC interconnectors.

A fourth problem is risk. Ultimately, market-based lines are rewarded by the revenues coming from flows and prices determined in the market. Provided liquid markets for these financial instruments exist, it is possible to hedge these risks but the hedging will never be perfect. Insulation against price volatility can be achieved, but hedging quantity volatility as well seems more difficult. Quantity is the main point which cannot be controlled on a non-controllable line and hence risks seems higher for non-controllable lines.

Further research might focus on the following two aspects. First, the distinction between controllable and non-controllable flow might distort investment decisions between different types of technology. To determine whether this is an empirically relevant effect, demands further examination. Second, the term 'unregulated' as used in this paper means that the revenues are not regulated. At the same time, a regulator or legislator might well require other regulatory provisions, for instance concerning third-party access to the line. The approaches differ quite strongly between the USA and Australia; the framework in Europe still has to be settled.

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