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Network Costs and the Regulation of Wholesale Competition In Electric Power

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Abstract

We characterize the cost function for electric power transmission. It is complex and non-linear, exhibiting scale economies over its range. The social planning problem for network transmission expansion is illustrated with a simple numerical example. The regulatory problem for joint generation and transmission cost minimization is addressed. It is shown that information asymmetries about the transmission cost function can lead to coordination losses when there is competition in the generation segment. We parametrize the tradeoff between potential coordination losses in transmission planning and benefits of competition and examine some potential alternatives for improved regulation of the transmission planning process.

1. Introduction

Under recent proposals to increase wholesale competition in the generation sector of the electric utility industry, transmission services would be unbundled, while the generation sector is opened up for competition. (See, for example, Einhorn (1990, 173-189) and Hogan (1992, 211-242).) The proposals promise increased competition and a decreased role for regulatory oversight, but tend to focus on operational considerations and ignore transmission capacity expansion.

An increasingly common arrangement in the electric utility industry is for the regulated utility to own some generation resources, but also provide transmission interconnection for competing private suppliers. The utility must then plan transmission expansions to accommodate the suppliers. Acute problems may arise with such arrangements, however, because the regulated firm has private information about the costs of transmission and can use this information strategically. Where interconnection fees are paid by the private generators, the utility can use its private transmission cost information strategically to burden private producers with interconnection fees that are in excess of costs. Under this arrangement, the regulator must administer a competitive balance between the utility and private generators.

Control of the transmission network has been clearly identified as the central focus of policy on competition in electricity. Policy analysis such as the Federal Energy Regulatory Commission (FERC) Transmission Task Force Report (FERC 1989) recognizes the difficult regulatory and incentive problems involved in expanding transmission capacity. Related literature on the information and regulatory problems associated with wholesale competition in electricity has addressed the transmission planning problem at a fairly abstract level (Gilbert and Riordan 1992).

In this paper, we first demonstrate that the cost structure of electric transmission is inherently complex, even for an extremely simplified example system. This complexity arises from economies of scale, lumpiness, and reliability criteria. These important features of transmission technology are typically down-played in classical economic analysis but will be emphasized here. We will argue that, even in the simplest of cases, the social planning problem for transmission network expansion has considerable computational complexity, making it difficult to understand even in the presence of full information. In practice, information asymmetries raise two problems: the potential for strategic use of information and the potential for losses in coordination economies.

While recent proposals for utility resource acquisition through auctions may mitigate the first problem to a great extent (Shirmohammadi and Thomas 1991, 316-323), the second problem remains. Losses in coordination economies can occur because the location decisions of private generators may not be known by the utility in sufficient time to plan network reinforcements optimally. Under these circumstances, generators may be interconnected 'one-at-a-time' through radial extensions that are collectively more expensive than jointly-planned network expansions. The private generators do not know the optimal transmission capacity expansion plan, since they do not know the cost function. The utility does not know where the new generation will be located, so it cannot plan optimally even knowing the cost function.

With greater coordination of transmission plans, there is an opportunity to realize scale economies. Unless siting locations are known with sufficient advance notice, however, these scale economies will be lost. Nevertheless, in this paper, we argue that the coordination losses are usually outweighed by benefits of competition, but that in some cases the transmission coordination losses are too large for competition to be beneficial.

In section 2, we provide a summary of transmission costs in the aggregate, and we use data from several standard references to characterize the transmission capacity cost structure, including economies of scale, lumpiness, and reliability issues in transmission technology. In section 3, we analyze expansion of a hypothetical transmission network. We use an example representing the simplest possible network configuration and formulate the cost minimization problem for this case in the presence of full information. Even in this case, economies of scale, lumpiness, and reliability criteria combine to make a complex problem.

In section 4, we consider the problem faced by the regulator of an electric utility who has limited information. We estimate the extent to which benefits from competition in the generation segment offset coordination losses in transmission planning and what determines the trade-off. Broadly speaking, competitive benefits dominate coordination losses for baseload generation and, depending on relative interconnection costs, for some intermediate generation.

In section 5, we relate the example of section 3 to a case study of transmission construction to accommodate two qualifying facilities in California. The QFs, California Energy and Luz

International, were involved in litigation with their host utility, Southern California Edison, at the California Public Utilities Commission (CPUC) over the allocation of the costs of transmission construction necessary for interconnection (CPUC 1990). The planning problem described in section 3 is a simplification illustrating the essential features of this case; however, the real circumstances involved several further complicating issues that are described in section 5. We examine the potential alternatives for improved regulation of the transmission planning process in section 6. We conclude in section 7.

2. Transmission Cost Characteristics

In this section, we characterize transmission costs in the aggregate, and we describe the issues of economies of scale, lumpiness, and reliability in relation to electric transmission technology.

2.1. Aggregate Transmission Costs

Although transmission assets have strategic value, they are not typically a major component of the cost of electricity. We illustrate this by considering aggregate data on transmission investments by investor-owned utilities. Table 1 shows data on transmission and distribution construction expenses from 1983-1990 (EEI 1991). Column two shows the total construction expenditure in each year, while columns three and four show the amount of transmission and distribution expenditures, respectively.

These data show that transmission expenditures ranged from 6—11% of the total construction budget. We include data on distribution expenses, since there are sometimes ambiguities in the reported data on the difference between these categories. The growth in the share of transmission construction expenses in table 1 is due in part to the decline in the overall level of utility construction during this period. Distribution construction shows substantial growth in this period, compared to the flatter level of transmission investment.

There is substantial variation among electric utilities in the share of total assets devoted to transmission. Table 2 shows data on the share of transmission assets in the total of undepreciated electric utility plant for a selected group of large investor-owned utilities (EIA 1992). While the average proportion of transmission assets is about 12%, utilities that have historically been large scale wholesale purchasers, such as Consolidated Edison, San Diego Gas and Electric, and Southern California Edison, have about 20% of their asset base in transmission.

2.2. Economies of Scale

Classical economies of scale are described by a cost versus capacity curve whose average costs are decreasing. Transmission 'cost' should be interpreted as the cost per unit length. Transmission 'capacity' should be interpreted as the 'thermal' capacity of the line, in megawatts (MW), say. Thermal capacity is defined to be the maximum power that can be transmitted along the line without causing accelerated aging of the line. We ignore a number of other engineering factors that enter into the definition of transmission capacity and further complicate the cost structure.[1]

2.3. Lumpiness

The classical representation of economies of scale is not easily applied to a technology that exhibits pervasive lumpiness. The capacity of electric transmission facilities depends, among other things, on the operating voltage of the line. Operating voltages are standardized into a small number of widely spaced levels, so that the capacities are typically available only in discrete lumps. We will consider the case where two voltage levels, 115 kilovolts (kV) and 220 kV, say, are candidates for construction. These are the principal voltages at which large-scale independent generation projects will be interconnected. Figure 1 shows the construction costs versus capacity at these two voltage levels. The costs are in normalized money units and the lengths are in normalized distance units, based on the data in the standard references (EPRI 1986; Kelly et al. 1987).

At any given voltage level, it is standard practice to build towers to support either one or two sets of transmission lines. These are referred to as single-circuit and double-circuit construction, respectively. The capacity of double-circuit construction is approximately twice that of single-circuit construction; however, the costs of double-circuit construction are considerably less than twice the costs of single-circuit construction. Consequently, along a given corridor, the first, third, fifth, etc. lines have approximately the same costs, while the second, fourth, sixth, etc. lines, if built using double circuit construction, have a lower cost. This gives rise to the alternating staircase cost characteristic in figure 1. Assuming that all construction must be either at 115 kV or 220 kV, the minimum cost of thermal capacity is shown by the lower envelope of the two cost characteristics in figure 1.

Figure 1 illustrates significant economies of scale, but also reflects the lumpiness of construction. Lumpiness with economies of scale produces average costs that vary significantly as capacity changes, even at high levels of capacity. The average costs of the capacity in figure 1 vary by over fifty percent even at high capacity levels. A classical smooth representation of the cost of capacity is a poor representation of the real costs, but is a convenient simplification used in some analyses (Scherer 1976, 575-601).

2.4. Reliability Criteria

The thermal capacity ratings shown in figure 1 still do not provide enough information to design a transmission system. Transmission lines occasionally fail. To prevent failures from overloading other lines, it is standard practice to design transmission systems according to the '*N*-1 criterion' (Stoll 1989). This criterion requires that after failure of any one of the *N* lines in the system, load can still be served without overloading any of the remaining lines past their emergency ratings. For simplicity, we will assume that the emergency ratings of the lines that we consider are the same as the thermal ratings.

In general, to verify that the *N*-1 criterion is satisfied, 'loadflow analysis' (Bergen 1986; Stevenson 1982) must be performed for each possible outage of a line in the system. For real networks, this can be computationally intensive. In this paper, for the sake of simplicity, we will mostly be concerned with corridors of parallel, identical lines. In this case, failure of one line will cause the flow to redistribute evenly amongst the other lines. Therefore, in the absence of other means to supply load, the *N*-1 criterion requires that the flow down a corridor be no greater than the thermal capacity of the number of lines in the corridor minus one.[2] We will call this the 'reliable' capacity of a corridor.

Figure 2 shows the construction cost versus reliable capacity at 115 kV and 220 kV, respectively. The minimum cost of reliable capacity is shown by the lower envelope of the two cost characteristics in figure 2. Note that these costs apply for *de novo* construction: for example, it is not possible to start with 115 kV construction and achieve a higher capacity at 220 kV for the incremental costs implied in figure 2.

In contrast, consider the case where a line is added to reinforce an existing corridor of lines. Assume that all lines have the same voltage. Suppose that the existing corridor satisfies the *N*-1 criterion. To a first approximation, adding capacity will increase the *reliable* capacity by the added *thermal* capacity. Therefore, the cost of adding capacity, at the same voltage, to an existing reliable corridor is the cost of incremental thermal capacity, as shown by the lower envelope in figure 1.

In summary, incremental capacity costs depend on the level of existing capacity in the network. We have described two types of capacity. In the next section, we will illustrate these types of capacity with a transmission planning example. We note that in a real network the effects of 'reactive power' (Stoll 1989) and the network externalities of 'loop flow' (Hogan 1992, 211-242) make the effective cost of capacity highly dependent on knowledge of the existing capacity in the system.

3. Example Planning Problem

In this section, we characterize what we take to be the simplest possible transmission planning problem. It involves a choice between 'radial' interconnection and 'network' reinforcement for a generation source that is remote from the existing grid. We use the term 'radial' to describe any direct connection between two points. The term 'network' refers to any other indirect interconnection involving one or more intermediate points. The complexity of our example problem involves the coordination of transmission plans for the remote source with plans for generation expansion at a location that is already connected to the grid. We describe the situation qualitatively in subsection 3.1, formulate the cost minimization problem formally in subsection 3.2, and describe features of the solution in subsection 3.3.

3.1. Description

Figure 3 shows a simplified hypothetical transmission system. Node K is an existing center of generation joined to V, a load center, by a corridor of 115 kV and 220 kV transmission lines.[3] The corridor satisfies the N-1 criterion, but has no excess capacity. There is growing load at V. There is potential expansion of the generation capacity at both K and H; however, there is no existing transmission between H and K nor between H and V.

As discussed in the last section, transmission capacity expansion along the K—V corridor will expand the reliable capacity of the corridor by the thermal rating of the new line. Therefore, the reliable cost versus incremental capacity curve for the corridor is represented by the thermal cost data of figure 1. New transmission expansion along the H—K or H—V routes, however, has a reliable capacity versus cost curve as in figure 2.

Increased generation at K would be accommodated by increased capacity along the K—V corridor of lines. We classify this expansion as 'radial' since it is a direct connection between K and V. For generation constructed at H, however, there are two basic alternatives:

1. direct construction along the two unit long route from H to V, which is 'radial' expansion, or,

2. construction along the one unit long route from H to K, interconnection at K, and construction along the K—V corridor, which is indirect, that is, 'network' expansion.

Despite the network expansion being along a longer route, it is cheaper to satisfy the N-1 criterion along the K—V corridor because of existing capacity in the corridor. This can make network expansion from H via K cheaper than radial. Furthermore, if there is also incremental generation at K, economies of scale in K—V expansion can make the network alternative more attractive than radial expansion. Conversely, the scale economies may result in so much excess capacity that the network alternative is more expensive than radial. We examine these trade-offs in the next sub-section.

3.2. Social Problem

In this subsection, we formulate the problem of minimizing the cost of transmission expansion to satisfy fixed generation expansion plans at H and K. The overall social problem is then to minimize the total costs of generation and transmission over choices of generation expansion at

H and K. Consistent with the 115 kV and 220 kV transmission options, we assume that the total new generation at H and K is no more than approximately 1000 MW.[4]

Let the minimum cost versus thermal capacity envelope shown in figure 1 be described by the function $T(K)$ while the minimum cost versus reliable capacity envelope shown in figure 2 be described by the function $R(K)$ where K is the level of transmission capacity expansion. Let the increased generation at H and K be G_H and G_K respectively; let the increased reliable transmission capacity from H—K and H—V be $K_{H\text{-}K}$ and $K_{H\text{-}V}$, respectively; and, let the increased thermal capacity from K—V be $K_{K\text{-}V}$.

To satisfy transmission requirements, we must have:

$$\begin{aligned}
G_H + G_K &\leq K_{H\text{-}V} + K_{K\text{-}V},\\
G_K &\leq K_{K\text{-}V},\\
G_H &\leq K_{H\text{-}V} + K_{H\text{-}K}.
\end{aligned}$$

The first of these constraints ensures that there is enough transmission capacity to deliver the incremental generation at V; the second ensures that there is enough capacity leaving K to accommodate generation at K;[5] while the third ensures that there is enough capacity leaving H to accommodate generation at H. The reader can verify that these are necessary and sufficient conditions for adequate transmission. Other equivalent sets of constraints are possible.

The costs of the transmission expansion are:

$$2R(K_{H\text{-}V}) + \sqrt{3}\,T(K_{K\text{-}V}) + R(K_{H\text{-}K}),$$

where the coefficients follow from the lengths of the transmission paths in figure 3 and where the cost function, T or R is applicable depending on whether there is already transmission capacity in the corridor. For fixed values of G_H and G_K, the optimal transmission expansion is given by the solution to the following problem:

$$\begin{array}{rl} \textit{Minimize:} & 2R(K_{H\text{-}V}) + \sqrt{3}\,T(K_{K\text{-}V}) + R(K_{H\text{-}K}), \\ \textit{Subject to:} & G_H + G_K \leq K_{H\text{-}V} + K_{K\text{-}V}, \\ & \qquad\;\; G_K \leq \qquad\quad K_{K\text{-}V}, \\ & G_H \qquad\;\; \leq K_{H\text{-}V} \qquad + \quad K_{H\text{-}K}. \end{array}$$

3.3. Solution

In this subsection, we describe the characteristics of the solution to the transmission planning problem. By our definition of 'network' expansion, for a fixed G_H and G_K, the optimal expansion involves network construction if and only if $K_{H\text{-}K} > 0$. Figure 4 shows whether optimal construction involves radial or network expansion versus the amount of increased generation at H and K. Optimal expansion is always radial if $G_H = 0$ or if $G_K = 0$; that is, optimal expansion is radial if generation expansion occurs at only one of the sites. If there is expansion at both sites, then optimal expansion is more often network. For $G_H + G_K < 1000\ MW$, optimal expansion is almost always network.

Figure 5 shows the optimal cost of expansion versus increased generation. The overall social problem is then to minimize the total costs of generation and transmission over feasible values of G_H and G_K. There are large regions in figure 5 where the marginal cost of incremental capacity is zero due to the lumpiness of construction. Furthermore, there are large discontinuities in the cost and average cost functions even at high levels of incremental capacity, so that smooth approximations to cost functions assume away the complexity of the transmission decision process.

The transmission expansion costs in figure 5 are optimal for the given generation expansion at *H* and *K*. Suppose that, instead, the transmission needs for *H* were determined assuming no increased generation at *K*, and vice versa. Then the total costs to accommodate expansion at both sites are higher. As shown in figure 4, independent planning of the transmission needs of incremental generation at *H* and *K* will suggest radial transmission, which will usually be qualitatively in error compared to the optimal coordinated expansion.

Figure 6 shows the percent savings of the optimal joint plan over independent planning of the transmission requirements for *H* and *K*. Over wide ranges of values of G_H and G_K, the optimal joint plan is considerably less expensive than independent planning. Joint planning to accommodate expansion at both *H* and *K* often allows a single larger transmission line to be built between *K* and *V* to take advantage of economies of scale. However, with other transmission configurations, independent planning may under-estimate costs due to network effects not considered in this paper. Independent planning not only yields plans that are qualitatively different from the optimal, but also yields costs that differ significantly from the optimal costs.

Due to the lumpiness of construction, there can be 'excess' capacity in an optimally planned system. If the excess capacity can be used in the medium term for transmitting power from subsequently built generation capacity, then the effects of lumpiness can smoothed; however, radial transmission built to access isolated producers may not be easily marketable. Historically, it has been assumed that excess capacity will be used eventually as the system grows, so that in the presence of fast anticipated growth, the economies of scale and long-life of transmission capital dictate overbuilding relative to current needs. This has been the rule of thumb in transmission planning; however, if transmission costs are assigned to third parties, they may be unwilling to pay for overbuilding relative to their minimum needs (Hunt 1992). Furthermore, historical rates of load growth may no longer be sustainable.

In summary, economies of scale and the reliability criterion significantly influence planning by making network expansion relatively cheaper than radial. In the planning of real transmission networks, the choices are often between many more than two possible expansion options, since the transmission system is usually much more complicated than in our simplified example. There may be some excess capacity already in the network, making the incremental capital costs of increased loading essentially zero. In practice, characterizing the incremental cost function is much more difficult than described in our example. In the next section, we will explore the ramifications of this social planning problem for a regulator.

4. Regulatory Problem

The regulator's problem, narrowly construed, is to set up conditions that will achieve the welfare optimal transmission plan, or close to it, in the face of the limited information the regulator has concerning costs and excess capacity. More broadly, this objective must be traded off against other possibilities for minimizing the cost of electricity.

Under vertical integration of the electric utility industry, the utility plans both generation and transmission expansion. Because the utility is aware of its potential generation opportunities, there is usually ample opportunity for the utility to coordinate and optimize its generation and transmission plans. In terms of the problem formulated in section 3, the utility can optimize the generation and transmission plan with full information. The optimal solution may involve some excess transmission capacity due to scale economies and lumpiness. The regulator faces the traditional problem under vertical integration of motivating the utility to optimize its capital planning, having only limited information about costs. This problem has been treated at great length in the public utility economics literature (Berg and Tschirhart 1988; Crew and Kleindorfer 1986) and will not be considered further here.

In the next subsection, we focus on the joint costs of generation and transmission expansion under partial vertical disintegration. In subsection 4.2, we characterize the trade-off between the benefits of competition in generation and the coordination losses in transmission planning. In subsection 4.3, we give numerical estimates of the key parameters and draw out some of the implications of these estimates.

4.1. Partial Vertical Disintegration

As indicated in section 1, the information needed to perform the calculation of the transmission cost function is usually under the exclusive control of the utility or group of utilities owning the network. Under partial vertical disintegration, information asymmetries between the transmission owner and independent producer over transmission costs and capacities confer market power to the transmission owner. Recent proposals requiring that utilities reveal transmission interconnection costs to private generators *prior* to formal competitive bidding mitigate this problem to a substantial degree. However, the disclosure typically involves estimates of the radial interconnection costs with the utility performing detailed network planning only after the bids have been accepted and contracts signed (Shirmohammadi and Thomas 1991, 316-323). It is also possible that the utility may estimate uniformly high interconnection costs to keep out competition, or to increase the regulated asset base if competitors are allowed entry.

When independents are allowed entry, the problem still remains of integrating their transmission needs into the long-term transmission plans of the utility. For example, if the generation additions at H and K in section 3 are privately owned, the utility may not know how much capacity will be interconnected at both sites in time to plan optimally and take advantage of coordination economies. In contrast, utility plans for generation will be available to utility transmission planners at a much earlier stage of development. Large transmission projects typically must be certified at a public utility commission, necessitating lead times for transmission projects that are as long or longer than the lead times for generation projects.

Therefore, gains from competition in the generation segment may be offset by coordination losses in transmission planning.

To attempt to eliminate the coordination loss, the regulator might require the utility to investigate and disclose all possible transmission expansion plans involving multiple site locations. The example in section 3 indicates that this task is at a minimum computationally challenging, even in the simplified case described there.

On the other hand, even if some limited approximation to disclosure of all possible transmission plans were available, the regulatory outcome might still not be desirable. Suppose the utility does disclose information on the potential economies of joint siting and interconnection. Two bidders might then coordinate their proposals to capture these economies. The net social economy would not necessarily be reflected in lower prices paid by utility ratepayers, since collusion between bidders could capture most of the rent through higher bids for generation.

In summary, the planning problem is exacerbated in a partially disintegrated industry compared to a vertically integrated industry. This situation is becoming more typical as utilities contract with independent power producers and qualifying facilities. Under partial disintegration, the regulator has the opportunity to drive down the price to the ratepayers through competition in the generation segment. Since the cost of generation is often substantially greater than the cost of transmission, as suggested by the data in tables 1 and 2, small economies in generation may outweigh coordination losses in transmission planning. For this reason, there is strong pressure away from vertical integration in electricity. It is not clear, however, how far the competitive pressure in the generation segment should be pushed.

An appropriate regulatory policy involves balancing the gains from competition in the generation segment against the potential coordination losses in transmission planning. We formalize this trade-off to determine the conditions under which the gains from competition in generation exceed the coordination losses in transmission.

4.2. Formulating the Trade-off

From figure 6, we observe that, over a wide range of choices of generation expansion, the coordination losses of independent planning are relatively large as a fraction of the transmission expansion costs. These losses occur regardless of what type of generation capacity is installed. We can express the transmission coordination losses as the product of the percentage coordination loss, *CL*, and the total transmission expansion cost, *TC*.

In contrast, the benefits of competition in generation depend partly on the type of generation capacity installed. They are typically greater for baseload generation, which operates for most hours of the year, than for peaking generation, which operates for brief periods of time. We parametrize the costs and benefits of competition in the generation segment to illustrate the importance of this effect.

We express the gains from competition in the generation sector as the product of a percentage competitive benefit, α, and the cost of generation, GC. The generation costs, GC, are the sum of fixed costs, FC, and total variable costs. Total variable costs are approximately proportional to the number of hours per year that it is optimal to operate a particular generator. This optimal operating profile is determined by simulation of the power system dispatch (Stoft and Kahn 1991, 275-286). We use standard power industry terminology to describe the operating profile as a capacity factor, CF. Finally, it is convenient to define a proportional relationship between variable generation cost and TC, parametrized by a multiplier β. Therefore, the gains from competition are $\alpha[FC + \beta \cdot CF \cdot TC]$, and they exceed coordination losses for those capacity factors that satisfy

$$CF > CL/\alpha\beta - FC/(\beta \cdot TC).$$

By estimating the parameter values in the right hand side of this expression, we can gain some insight into the conditions that are likely to make competition the desirable regulatory strategy.

4.3. Numerical Estimates

There are estimates of the value of α available in the literature. The range is approximately between 0.1 (Kahn 1991, 30-45) and 0.2 (Lieberman 1992). From figure 6, a typical value of CL is 25% in the region $G_H + G_K < 1000\ MW$. Based on these estimates, CL/α is between 1 and 3. The generation costs, GC, are known approximately as a function of CF. In present-value \$/kW,

$$GC\ (CF) = 600\ \$/kW + CF \cdot 4700\ \$/kW.$$

This approximation is consistent with avoided cost information used by Consolidated Edison in a competitive bidding context (Consolidated Edison 1990). On the basis of this parametrization, $FC/(\beta \cdot TC) = 13\%$.

To determine β, we estimate TC and use the relationship between variable generation costs and transmission costs: $\beta \cdot TC = 4700\ \$/kW$. TC can be quite variable, depending upon local conditions. A typical range is $TC = 200 - 300\ \$/kW$ (Pacific Gas and Electric 1991). A high cost case, such as Consolidated Edison, would be $TC = 1000\ \$/kW$. Using this range of values, we get $20 > \beta > 5$.

The implication of these estimates is the following. For most cases where transmission costs are small compared to generation costs, competition is beneficial for $CF > 10\%$. This means that only the 'peaking' technology segment of the market should be protected from competition. In areas where transmission system costs are high, competition should be confined to high capacity factor (baseload) market segments. For $\beta = 5$ and $CL/\alpha = 3$, the critical capacity factor is around 50%. In this case, the intermediate load segment of the market may or may not be a beneficial arena for competition. The high transmission cost case may arise either in areas of high urban density (this is the case for Consolidated Edison) or because the interconnection distances are long. This latter case is likely for renewable energy projects, which are frequently located remotely relative to the main transmission corridors.

5. Kramer-Victor Case Study

The example discussed in section 3 and illustrated schematically in figure 3 is based on the interconnection plans and fees proposed by Southern California Edison (SCE) for privately-owned QF generators sponsored by California Energy and Luz International. A total of approximately 630 MW of QF generation was built or proposed by California Energy and Luz International. California Energy is a geothermal producer. Luz International built solar thermal power plants based upon its own proprietary technology.

This case study illuminates the origin of the coordination losses in transmission planning. The strategic use of private information by the utility was also an issue in this case. Conflicts among the parties concerning cost allocation issues resulted in adjudication at the California Public Utilities Commission (CPUC). The best summary of the issues litigated in that forum is the CPUC decision allocating the costs of the final network proposal, which we refer to below as Proposal 3 (CPUC 1990).

Figure 7 is a schematic of the various interconnection plans SCE proposed to California Energy and Luz. Figure 3 is essentially a simplified version of the interconnection plans in figure 7. The line labelled Proposal 1 in figure 7 represents the first plan to interconnect Luz with SCE. It is just the kind of radial interconnection that is only efficient in the absence of generation at the Kramer substation. California Energy proposed to deliver its capacity to Kramer. There was some dispute about the extent, if any, of available transmission capacity in the existing Kramer-Victor corridor. California Energy argued that under CPUC policy on interconnection, the availability of existing Kramer-Victor transmission capacity was irrelevant; the only obligation on the QFs was to deliver to the nearest substation, which in their case was Kramer.

Subsequently, SCE offered two additional alternatives, Proposal 2 and Proposal 3. Proposal 3 was eventually adopted as a result of the CPUC decision two years later. Proposal 2 is a radial connection between Luz and Victor which simply follows the existing Kramer-Victor (K—V) corridor. Proposal 3 involves a major upgrade of the existing facilities on the K—V corridor, relying on scale economies, but also resulting in excess capacity. It is the 'network' version of Proposal 2. The CPUC required California Energy to pay for about 20% of the K—V upgrade and also half of some (much smaller) interim upgrade costs. SCE was allocated 35% of the K—V upgrade cost, corresponding approximately to the amount of excess capacity beyond the needs of the QFs. Luz was allocated the balance of the costs, which was about 20% (or $11 million) less than the allocation under Proposal 1. For further details see Baldick and Kahn (1992).

Future arrangements between private producers and utilities in California may defuse the types of disputes over cost allocation that occurred in this case (Hunt 1992; Shirmohammadi and Thomas 1991, 316-323). However, coordination issues are likely to become more prominent. The reason is that the expected interval between project selection and interconnection will be short, and there will be longer intervals between successive project selection competitions. Therefore, inefficient radial interconnections are more likely to occur, and there will be fewer opportunities to find more efficient network solutions. The analysis of section 4 nevertheless suggests that, for most types of generation capacity, the benefits of competition outweigh the coordination losses.

6. Institutional Reform

Traditionally, transmission planning has involved a 'club' process to coordinate activities among vertically integrated utilities (Hogan 1992, 211-242). These processes were typically informal and involved little or no regulatory oversight. Independent power producers are unlikely to be invited to participate in this club coordination process. Therefore, to address the information problems that lie at the heart of transmission planning with independent power production, it will be necessary to provide for them in some kind of regulation (Hogan 1992, 211-242).

The Advance Plan (AP) process administered by the Public Service Commission of Wisconsin (PSCW 1989; 1991) represents a useful model of how this might work. Under the AP process, all utilities in the state participate in joint planning to meet the identified transmission capacity expansion requirements. The joint study process is overseen by regulatory commission staff who participate actively in the evaluation of alternatives (Arny 1992, 18-23). The regulatory authority to order and oversee this process is unique in Wisconsin, where both investor-owned and government-owned utilities are subject to the AP requirements. Independent power producers have the legal right to participate in the AP process, including the joint planning studies.

The main difference between the AP framework for transmission planning and the previous forms of club operation is the role of the regulator to act as referee. Informal club operation is likely to be subject to the market power of dominant players. A public process with shared information and joint studies is much less amenable to the strategic uses of private information. The AP process works particularly well because all the utilities involved are of very roughly equal size. There is no single dominant entity or set of entities. Therefore, information pooling is likely to be reliable, and bargaining coalitions may not be stable as the interests of various parties shift.

There are several barriers to the successful generalization of the AP process to other settings. First, legal jurisdictions are unlikely to be complete in other situations. Where utilities in different states must plan jointly, for example, there is no single applicable regulatory authority to act as referee. Recently, there have been proposals for binding arbitration between coalitions of transmission users and suppliers. (See, for example, the case studies in Baldick and Kahn, (1992).) Agreements for binding arbitration for dispute resolution are a weak substitute for legal authority, but may be superior to no mechanism.

Second, there are many situations in which the potential discipline of multiple participants may not be available. The key ingredient for potential discipline is knowledge of the parameters characterizing the portion of the transmission network under examination. Thus, the Kramer-Victor dispute failed to reach easy resolution in part because the two QFs had no way of verifying or effectively questioning the technical assertions of the host utility. If this had been a wheeling transaction, however, and the ultimate purchaser was another utility, that utility might well have had at least some of the relevant information.

Despite the potential difficulties of fractionated authority and residual market power, some form of club process based on voluntary participation, open information exchange, and the responsibility to report to existing regulatory authority provide the outlines of an institutional framework that can help improve the coordination of transmission planning. Private producers will have to incur some information gathering costs in such processes to defend their interests.

7. Summary and Conclusion

Transmission capacity expansion is an essential feature of wholesale competition in electricity. The cost structure for this kind of capacity is complex even in what appears to be relatively simple cases. The utility, as a monopoly supplier of this capacity, has private information about these costs that is very difficult for the regulator or private suppliers to audit or verify. Under vertical integration, the utility can, in principle, optimize the joint costs of generation and transmission system expansion. Unfortunately, the regulator can never really be assured that the minimum cost solution has been obtained.

The regulatory motivation for wholesale competition in generation is price reduction. The competitive process for selecting private suppliers must be coordinated with the transmission impacts of such selection. Because the interconnection of private suppliers is typically a 'one-at-a-time' process, the coordination economies of network expansions may be lost. It is practically infeasible to require the utility to disclose the costs of all possible network expansion alternatives in advance of bidding for generation capacity. Furthermore, pursuing this goal will only encourage collusion among bidders. Therefore, the regulatory policy of wholesale competition will inevitably result in some transmission planning inefficiencies.

We have estimated the extent of these inefficiencies, compared them to potential gains from competition, and derived a relation characterizing when the balance favors competition. Broadly speaking, this usually occurs for generation capacity that is optimally dispatched in the baseload or intermediate mode. For peaking generation (capacity factor of less than 10%), the competitive benefits may be insufficient. In systems with very high cost transmission, the critical capacity factor for competition benefits is much higher. We gave an example where it is approximately 50%.

Many of the problems identified here have already occurred to one extent or another in the private wholesale markets. The Kramer-Victor case is one example. Institutional reform, centering on open joint planning processes with active participation by regulators and private producers, is a promising approach to ameliorate these problems.

Notes

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1. For example, issues such as losses, reactive power, surge impedance loading, and emergency ratings of the line will be ignored in this paper. These concepts are described in detail in Stoll (1989).

2. This simplification applies only to corridors of parallel identical lines. In general, a corridor may consist of different types of lines, or two points can be joined by lines along several different paths. In this case, loadflow analysis is usually necessary to determine whether the *N*-1 criterion is satisfied.

3. In a real transmission system, the configuration of lines joining generation to load centers would be much more complex. In this stylized example, a single corridor of lines represents the whole existing transmission network.

4. For generation increments greater than 1000 MW, economies of scale would encourage us to also investigate transmission construction at 345 kV and 500 kV. However, we do not expect there to be many independent power projects with capacities larger than 1000 MW.

5. We assume that all generation at K can be thought of as flowing along the K—V corridor. This is not true in general because of 'loop flow;' however, the assumption is innocuous here.

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Table 1. Transmission and Distribution Construction Expenses - Investor-Owned Utilities

Year	Billions of $			%	
	Total Construction	Transmission	Distribution	T&D/Total	Trans/Total
1990	22.6	2.5	9.1	51	11
1989	23.1	2.5	8.7	48	11
1988	21.8	1.9	8.2	46	9
1987	25.5	2.1	7.4	37	8
1986	29.3	1.7	6.6	28	6
1985	31.1	1.8	5.9	25	6
1984	33.4	2.2	5.0	22	7
1983	38.8	2.3	4.8	18	6

Table 2. Share of Transmission in Total Assets of Selected Investor-Owned Electric Utilities

Utility	Net Electric Utility Plant (million $)	Total Transmission Plant (million $)	Transmission/Total Plant %
Consolidated Edison	7054	1558	22
San Diego Gas and Electric	2554	501	20
Southern California Edison	12379	2405	19
Duke Power	8450	1223	14
Pacific Gas and Electric	13504	1851	14
Commonwealth Edison	17821	1912	11
Baltimore Gas and Electric	3820	374	10
Houston Lighting and Power	8705	764	9
Texas Utilities	16655	1388	8
Philadelphia Electric	10089	685	7
Investor-Owned Utilities Total	455061	52630	12

Figure 1. Cost of thermal capacity, in arbitrary money units per unit length, versus thermal capacity. Capacity at 115 kV shown by the thin line; capacity at 220 kV shown by the thick line; minimum costs are given by the lower envelope of the two curves.

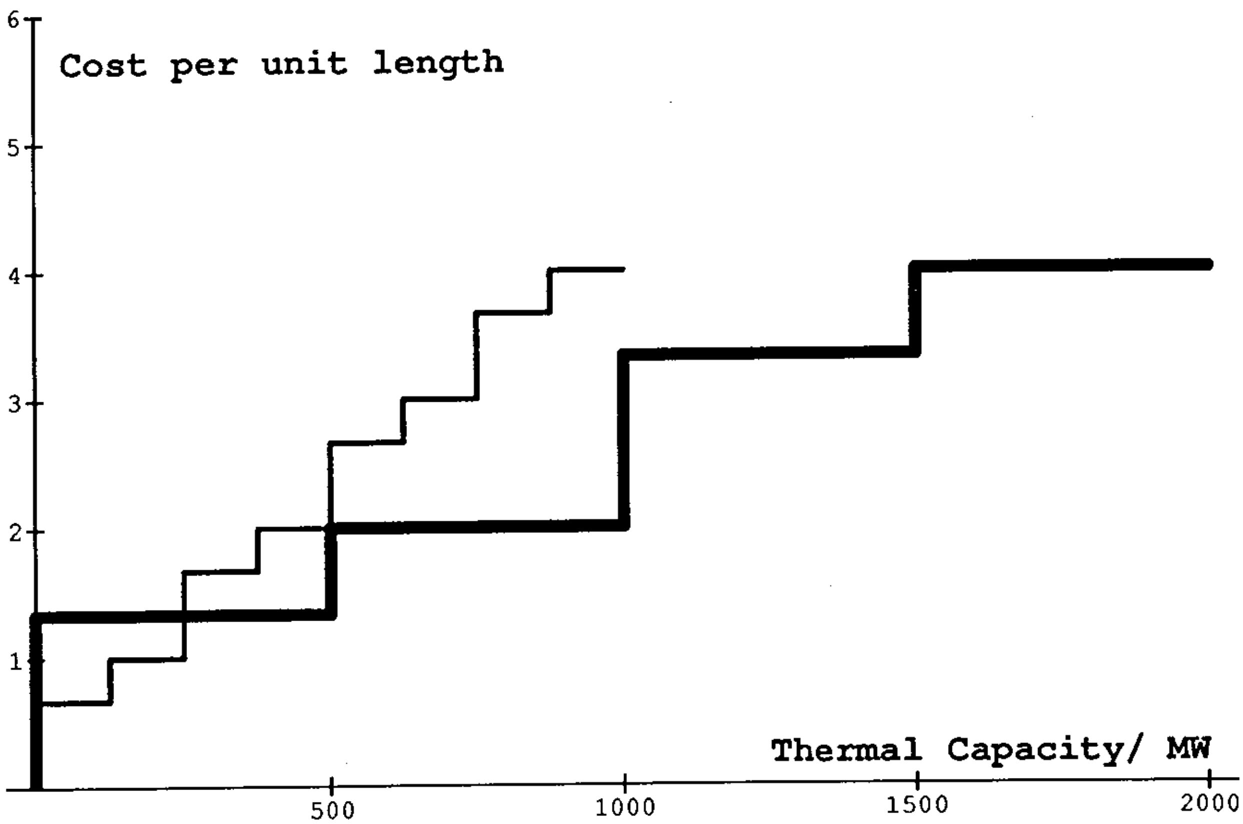


Figure 2. Cost of reliable capacity, in arbitrary money unites per unit length, versus reliable capacity. Capacity at 115 kV shown by the thin line; capacity at 220 kV shown by the thick line; minimum costs are given by the lower envelope of the two curves.

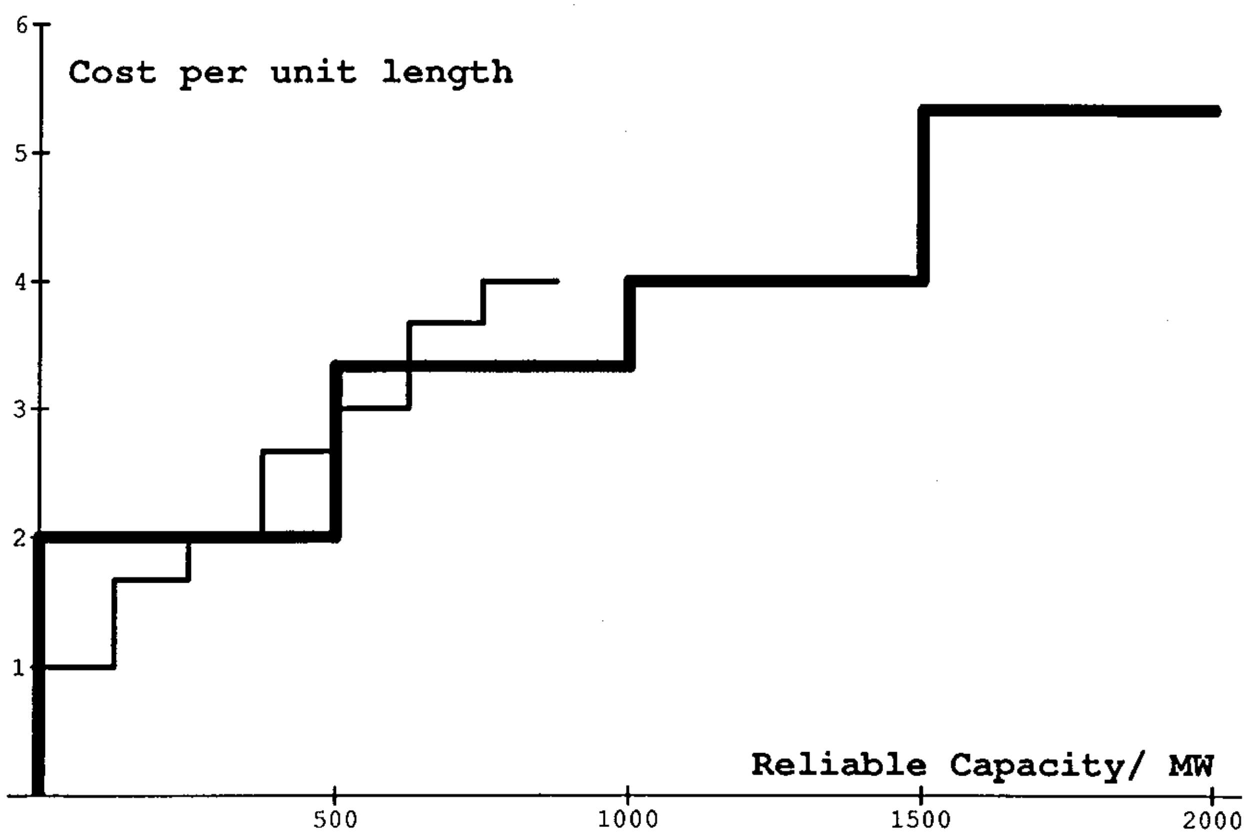
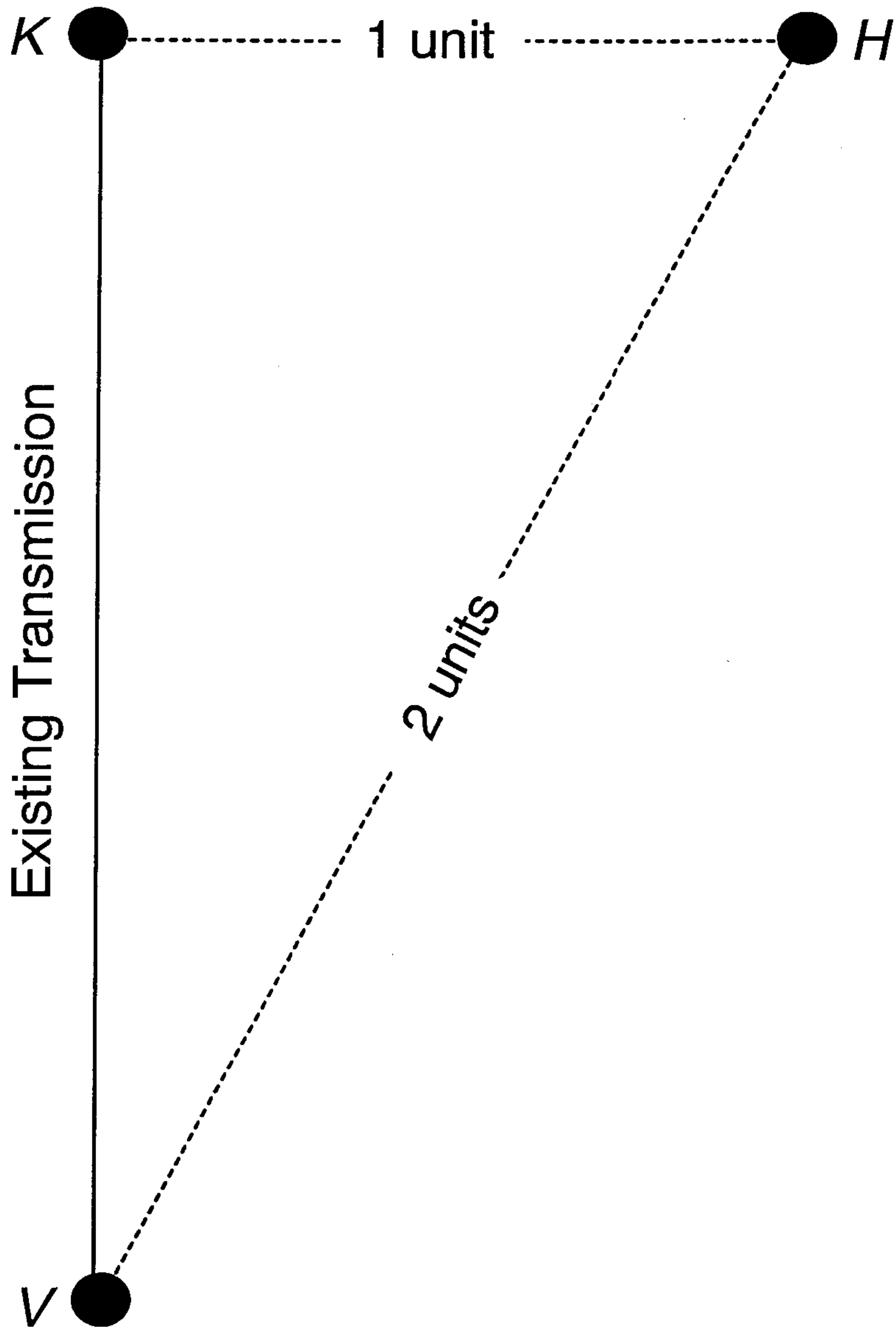


Figure 3. Example system.



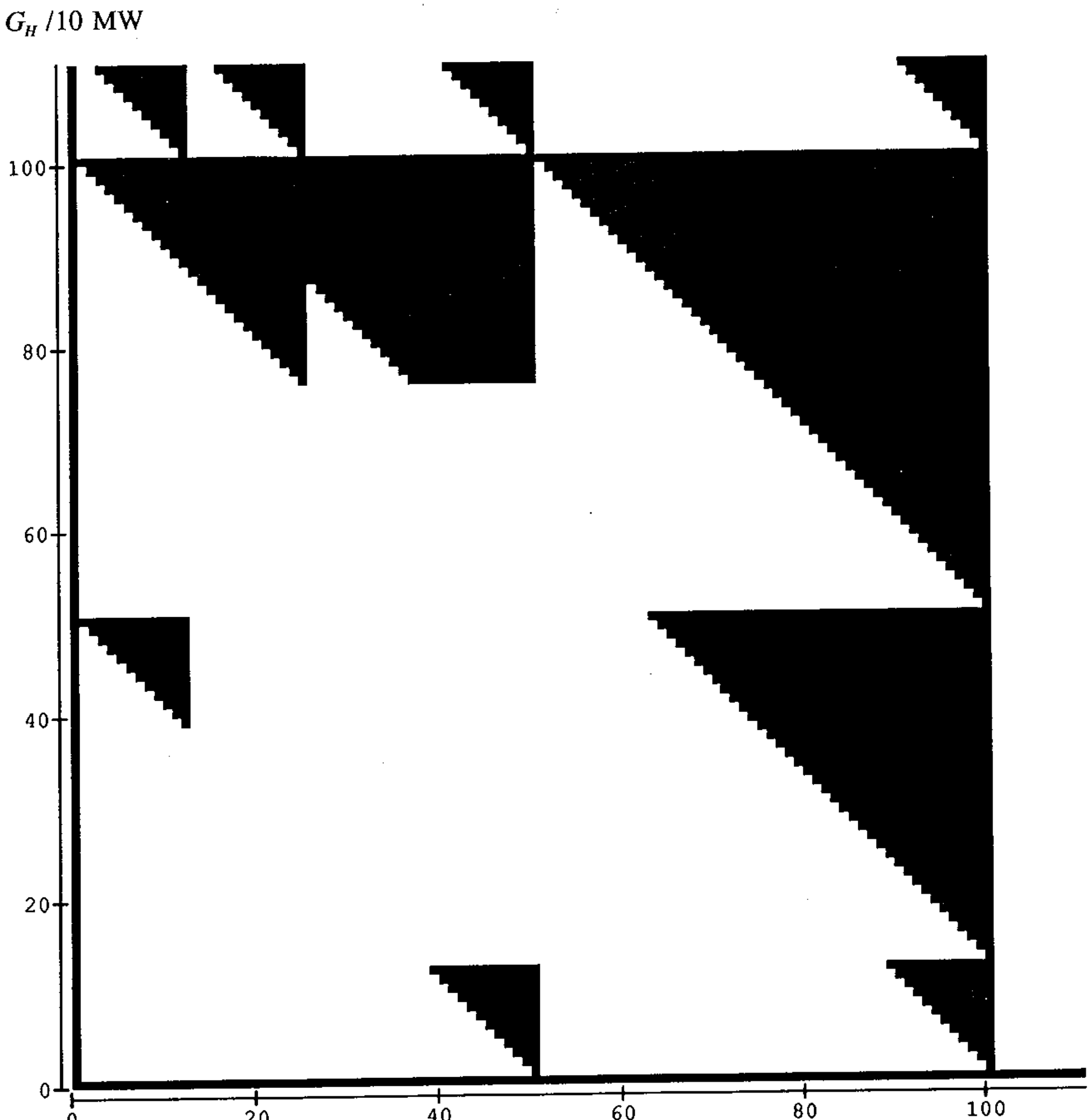


Figure 4. Qualitative nature of optimal construction versus generation expansion at H and K. Construction should be network in white regions, radial in black regions. (Optimal planning was performed for values of G_H and G_K in multiples of 10 MW. The shading of each 10 MW by 10 MW square represents optimal planning for the value of (G_H, G_K) in the bottom left corner of the square.)

Figure 5. Optimal costs of transmission versus generation expansion at H and K.

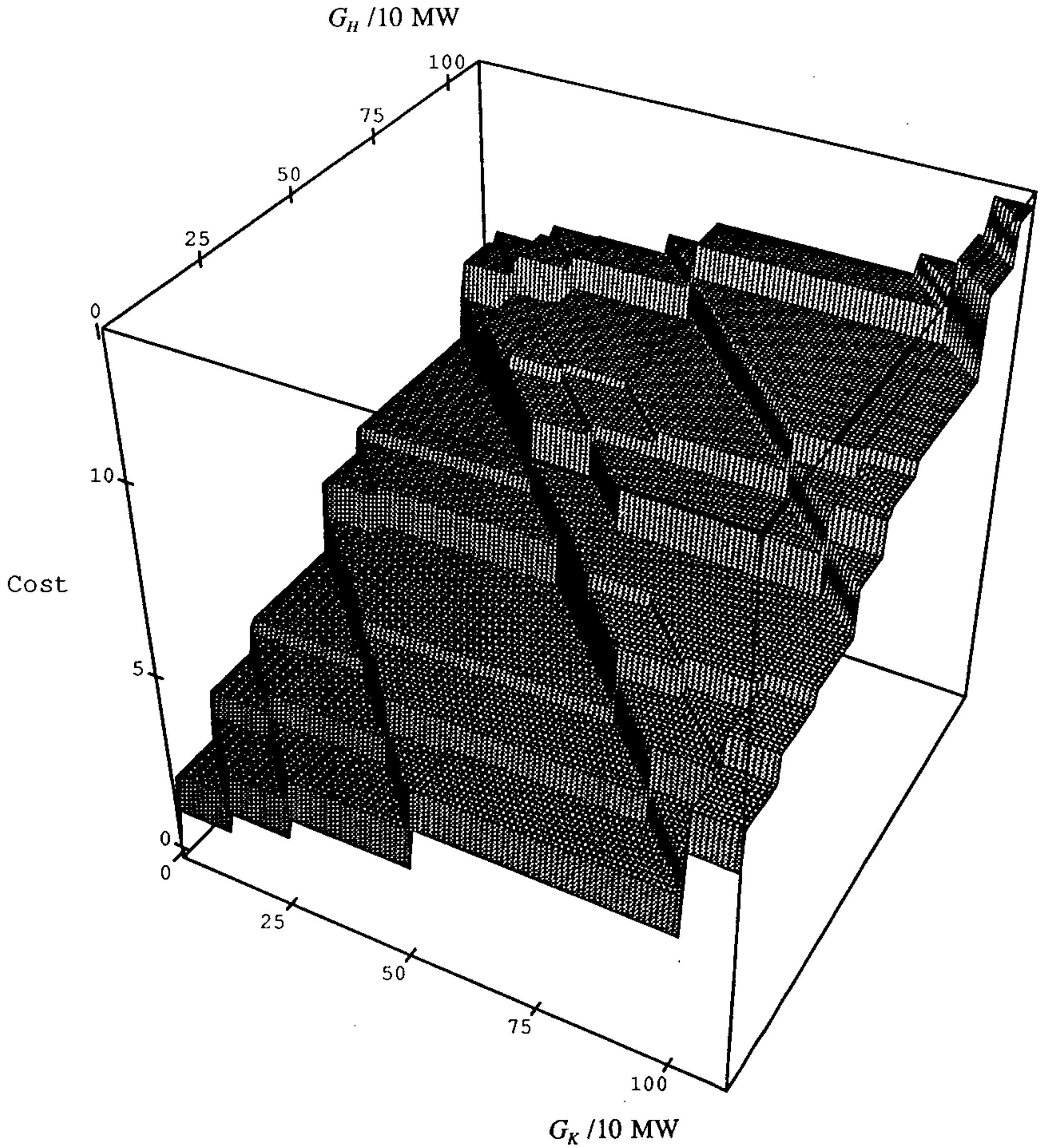
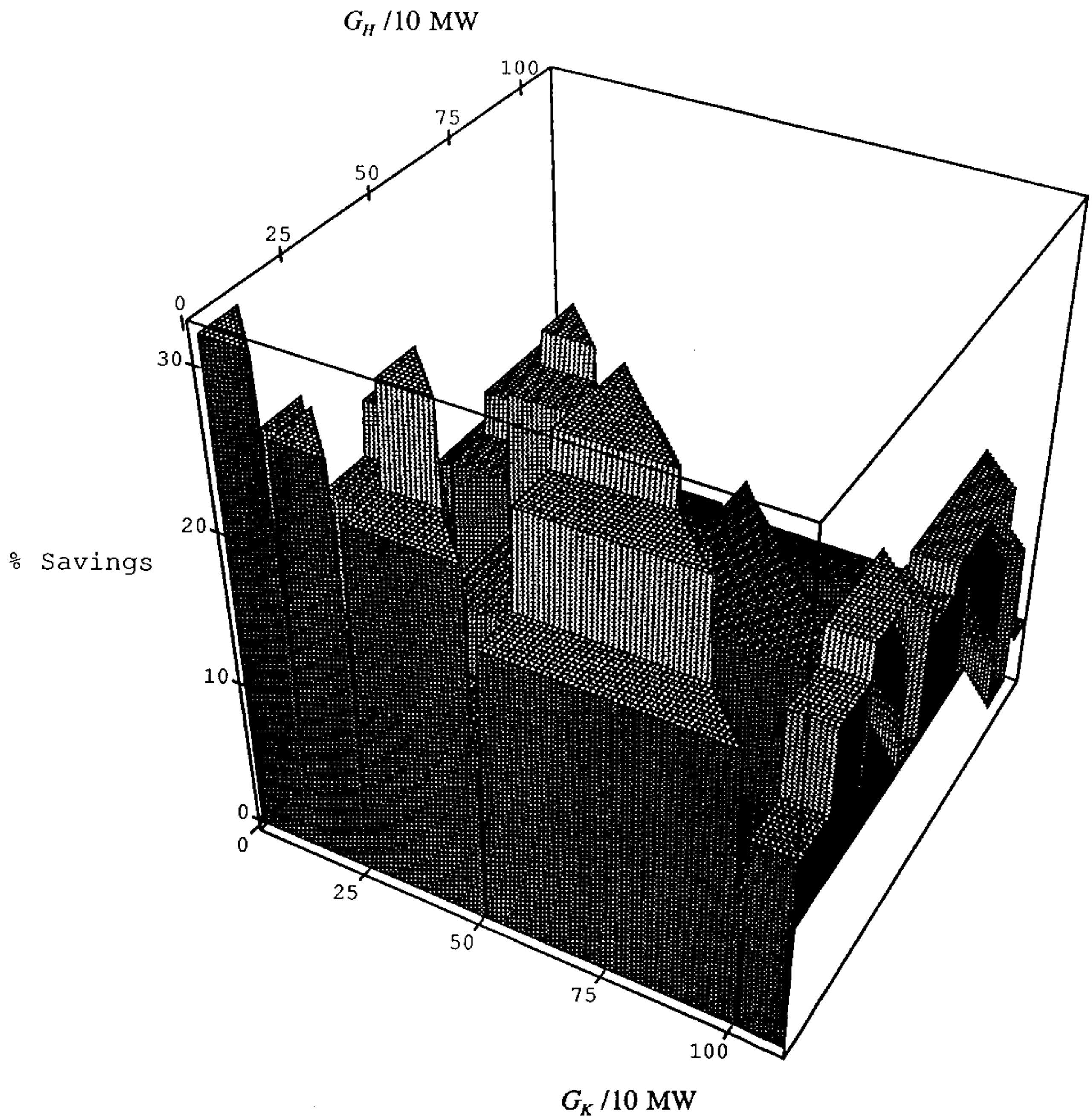


Figure 6. Percent savings of jointly optimal plan over independent planning versus generation expansion at H and K.



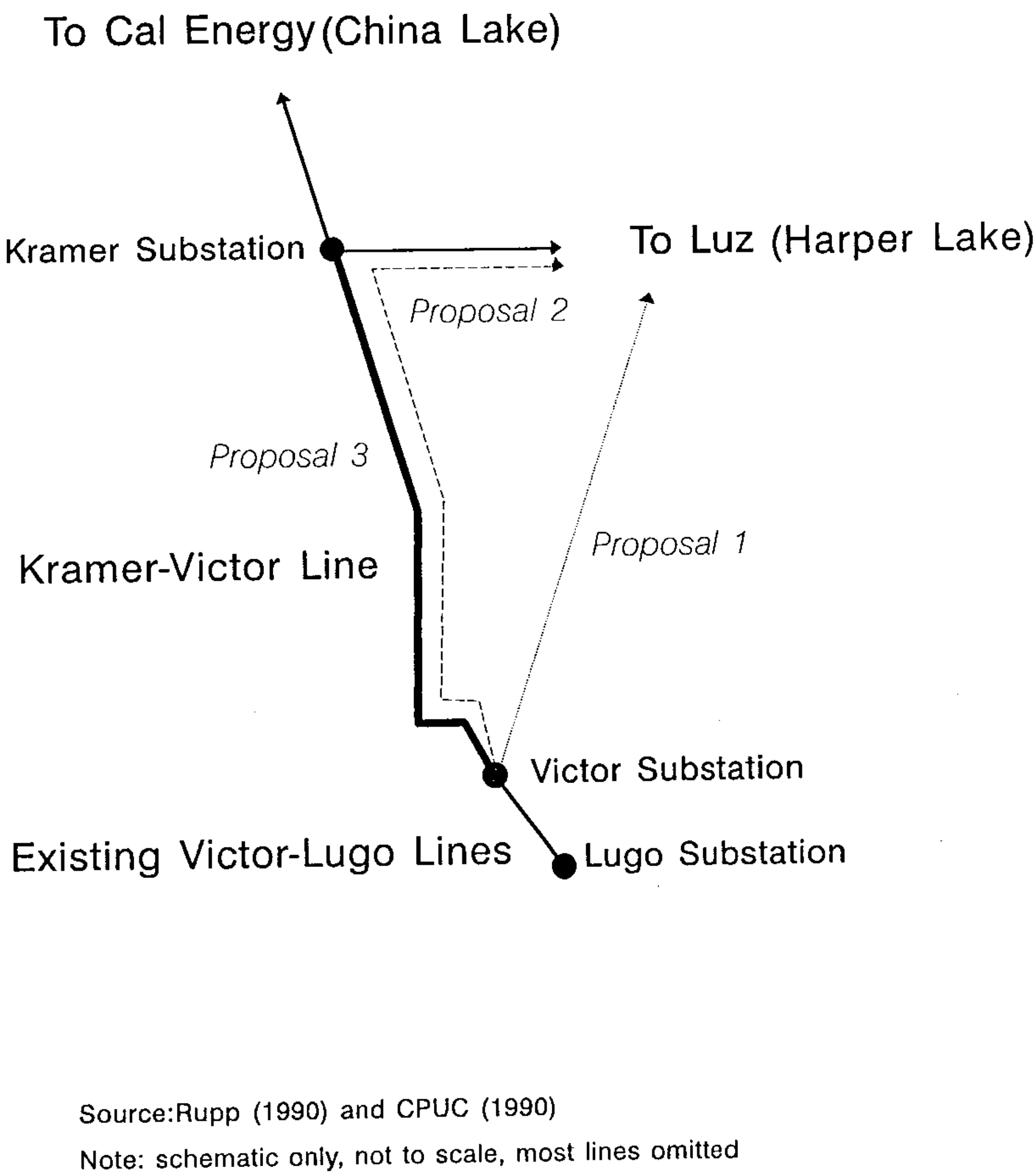


Figure 7. Map of transmission lines in Kramer-Victor case study.