Transmission Asset Investment in Electricity Markets

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Abstract: We construct a general analytic framework for the transmission network investment problem in the market environment and demonstrate its application to some test systems. We define a set of metrics to quantify the improvement attained in terms of welfare for all the participants and make use of them in the evaluation of the impacts of new transmission investments under competition. The proposed metrics are useful to the central entity responsible for transmission planning to provide meaningful measures of the effects of a modification in the grid over the planning horizon. The proposed framework is particularly useful to transmission network planners to support desired environmental targets. The analysis of the effects of new investments on the participants affected by the expansion includes the assessment of appropriate environmental attributes. The consistency of the measured values in terms of these metrics allows the comparison of disparate transmission investment projects and their effective prioritization. A key element of the framework is the deployment of an optimization scheme to maximize the social welfare with and without the transmission asset investments under various bidding behaviors of the market players and contracting conditions. We report the application of the proposed framework to investigate several transmission expansion scenarios on the IEEE 24-bus reliability test system network. The results on both pool-based markets and combined pool-bilateral contract markets provide a good illustration of the capability of the framework to effectively address realistic questions in transmission investment.

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Introduction

In the prerestructuring times, grid operations and planning were in the hands of the centralized entities that owned the grid as well as the generation and distribution facilities under a vertically integrated structure. However, the introduction of open access, the growth of competitive electricity markets and the unbundling of the electricity business have raised new challenges that the restructured industry must face. The restructuring of the electricity industry has resulted in the advent of many new players, such as brokers, marketers, and independent power producers. A key aspect of restructuring is the creation of new structures, such as the independent grid operator (IGO), and the separation of the control and operation of the grid from its ownership. We use the generic term IGO to refer to the entities called transmission system operators, independent system operators, and regional transmission organizations. These entities have the responsibility for regional planning in addition to ensuring reliable system operations and, in some cases, market operations. A salient characteristic of the new structure is the decentralized decision making. One critically important outcome of the restructuring is the more frequent stressing of the transmission grid due to the creation of congestion situations.

Congestion impacts market players in many different ways. Congestion may prevent the use of lower-priced generators to meet the load and consequently may result in a generation/demand schedule with higher total costs and losses of market efficiency. Also, congestion facilitates the opportunities to exercise market power through gaming by some players to increase their profits. A key requirement, therefore, is to have appropriate metrics to meaningfully measure the congestion impacts in power/energy and monetary terms. In the planning of new transmission asset additions, the reduction of congestion plays a key role. But, the objectives of market efficiency increase and social welfare maximization compete with those of the individual market players and of the investors. A key complication is that each market participant may be differently affected, faring better or worse as a result of congestion relief under the new investments.

Network expansion is a rather complex, multiperiod, and multiobjective optimization problem (Rosellón 2003; Sauma and Oren 2007). Its nonlinear nature and the inherent uncertainty of future developments constitute major complications. Under the vertically integrated structure, the construction of new transmission facilities has been associated with the addition of new generating resources and their integration into the existing network. This was done under the strong control exerted by the regulators over virtually every aspect of the regulated utility's activities. In the case of transmission asset investments, the planning objectives were, typically, simplified to the minimization of total costs. Under the new paradigm, the electricity markets, given the resulting prices and congestion metrics, need to be considered side-by-side with the economics of investment in the new assets. The fact that this is carried out in an environment of regulatory and legislative uncertainty and with the operational control of the facilities being vested in hands different than the ownership adds further complications.

There are various mathematical models used for solving the

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transmission expansion problem from the cost minimization standpoint. The solution techniques for this problem may be classified as mathematical optimization methods, including linear (Garver 1970; Villasana et al. 1985), mixed-integer linear programming (Romero and Monticelli 1994; Alguacil et al. 2003), Benders decomposition (Binato et al. 2001) and dynamic programming (Dusonchet and El-Abiad 1973), evolutionary computing, including genetic algorithms (Gallego et al. 1998) and simulated annealing (Romero et al. 1996), and game theoretic models (Contreras and Wu 1999, 2000; Zolezzi and Rudnick 2002). With the establishment of pool-based markets alongside bilateral transactions (Wolak 1997), the transmission expansion problem is formulated to maximize social welfare (Shrestha and Fonseka 2004; Contreras et al. 2005). Other work has focused on the integration of financial transmission rights (FTR) considered into transmission investment decisions (Hogan 1992) and the study of the interactions between FTR and market power. Efforts to study merchant transmission investment, locational market power, and imperfect competition have been reported (Joskow and Tirole 2000, 2005). A general market mechanism for electric power transmission is presented in (Chao and Peck 1996).

In this paper, the writers propose an analytic framework for the analysis of the transmission network investment problem in the restructured environment with markets coexisting with bilateral transactions. The writers address carefully the issue of formulating appropriate metrics that allow the quantification of the impacts of the bidding patterns of the market players and the contracting conditions on transmission asset investments. The framework is comprehensive as it represents many relevant aspects of the transmission asset investment problem in the competitive environment. In particular, the consideration of the assessment of a plan to meet desired environmental goals or policy requirements, including emission permit allocation and renewable resource penetration levels in the grid, is accommodated. A salient characteristic is the ability to compare on a consistent basis disparate transmission investment alternatives. Note that the proposed framework considers generation and transmission expansion separately as compared to (Sauma and Oren 2006), where the writers take into account the interrelationship between the generation and the transmission investments, and propose a new planning paradigm in deregulated electricity markets for studying how the exercise of local market power by generation firms affects the equilibrium between the investments in generation and transmission. The paper is structured as follows. Section "Transmission Investment Framework" provides the description of the multilayered analytic framework that has the capability to capture the various aspects of the transmission investment issues. Section "Proposed Metrics" presents the definition of relevant metrics to assess transmission asset investment(s) from the IGO point of view. In Section "Case Studies," the writers apply their analytic framework to the IEEE 24-bus RTS. We draw a number of important conclusions from our case studies and describe extensions of the proposed framework in our future work in the final section.

Transmission Investment Framework

The writers propose a general framework capable of dealing with the complexity of issues in transmission investment in competitive electricity markets by extending the analytical framework developed in Liu and Gross (2004, 2005). We use as a starting point the three-layer framework developed in Liu and Gross (2004, 2005). We add an investment layer for the analysis of expansion problems and construct the appropriate interconnections with the three layers. The extended framework consists of four interconnected layers—the physical network, the commodity market, the financial market, and the investment layers—and the associated information flows to describe the interactions between these layers. We briefly summarize the existing three layers of the framework.

The physical network layer is used to represent the transmission physical flows in the network. The relationships between the line flows and the nodal injections and the consideration of various network constraints allow the characterization of congestion conditions.

The commodity market layer represents the behavior of the pool market players in terms of their bids and offers, the requests for transmission by the bilateral transactions including their willingness to pay Liu and Gross (2004), and the IGO decision making process. This process requires the formulation of the so-called generalized transmission scheduling problem (GTSP) (Liu and Gross 2004), defined in the next section, to determine the hourly market outcomes of the players' sales and purchases, the transmission schedules, and the locational marginal prices (LMPs) at all grid nodes. The GTSP formulation encapsulates both the grid physical capabilities and the market information of all the transmission customers. The GTSP is essentially a statement of the problem solved by the IGO to accommodate the transmission service needs of the pool buyers and sellers and all the bilateral transactions without violating the grid physical constraints. The GTSP solution also provides essential information together with that from the physical network layer to the financial layer.

The issuance of feasible FTR and the evaluation of FTR payoffs are then used by the layers in various ways. The models of the FTR and the FTR markets constitute the financial market layer.

The addition of a fourth layer provides the capability to analyze transmission investment issues. This new layer is used to determine which transmission investment assets are possible candidates and when they will be added to the system. In other words, the problem has the dual objectives of selecting the optimal transmission investment decisions and determining the optimal combination of the selected assets over a time horizon spanning the planning horizon $\mathcal{H}$. The addition of this new layer requires the development of the appropriate additional information flows to represent the interactions between the four layers. These information flows are shown in Fig. 1. The writers discuss these flows starting with the investment layer, whose horizon is much longer than that of each of the other three layers. The hourly information from the commodity market layer consisting of the social welfare, the producer surplus, the consumer surplus, the congestion rents, and the market efficiency loss (all these terms are defined in the next section) is used by the new layer to determine the future investment asset additions.

The impacts of the changes in network topology are propagated throughout the other layers. In the financial market layer, the inputs to the FTR markets are the FTR requests of the transmission customers. The IGO decision-making process explicitly considers the *simultaneous feasibility test* (*SFT*) constraints (Liu and Gross 2005) using the hourly network layer information. The outcomes of the financial markets may impact the customers' bidding behavior in the commodity markets. The consideration of the physical constraints in the solution scheme of the hourly GTSP is an interactive process between the commodity market layer and the network layer.

The LMPs determined by the GTSP solution are the values of

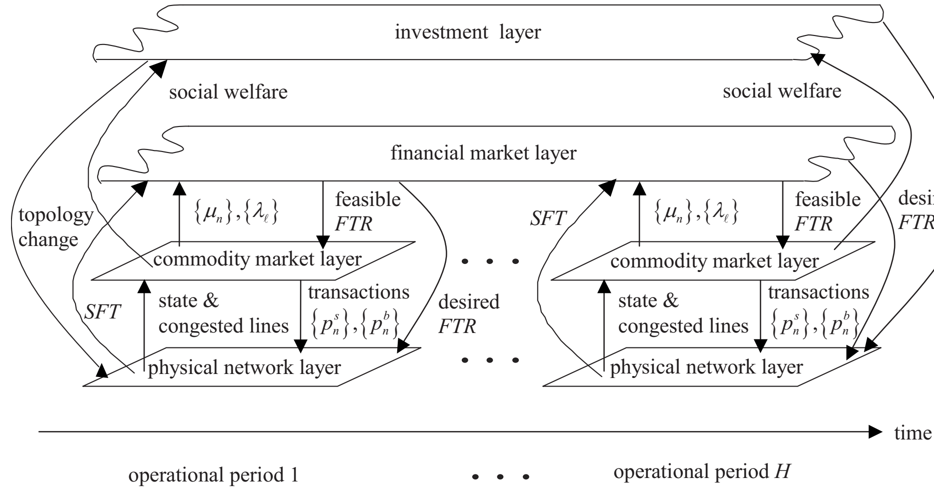

Fig. 1. Four-layer framework structure

the dual variables at the optimum and serve to provide the price signals to compute the market outcomes. The consideration of the physical constraints in the solution scheme of the hourly GTSP is an interactive process between the commodity market layer and the network layer. The LMPs determined by the GTSP as the optimal dual variables provide the basis for the financial market layer to evaluate the FTR payoffs.

Proposed Metrics

To assess the potential benefits of a new transmission asset investment it is necessary to define the metrics that measure that improvement. The metrics used are evaluated from the IGO point of view. We use several metrics such that the IGO can evaluate investments in transmission assets: the *social welfare*, the *loss of efficiency*, and the *congestion rents*. We also consider two additional metrics not related to the IGO, the *producer surplus* and the *consumer surplus*, for the sake of completeness.

The first metric, the social welfare, is an important metric since it measures the overall impact of both sellers and buyers in pool-based markets. The double auction market mechanism used has the objective of maximizing the social welfare, so as to determine the maximum net benefit for society. If bilateral transactions are included in the formulation, we can redefine social welfare as the measure of the net benefits of both the delivered bilateral transactions and the sales and purchases in the pool market.

Without loss of generality, we assume a single seller and a single buyer at each node $n=0, 1, \cdots, N$ of the network, where $\mathcal{L}=\{1, 2, \cdots, L\}$ is the set of lines and transformers that connect the buses of the network. The node n selling entity's marginal offer at hour h is integrated and denoted by $\beta^s_{n,h}(p^s_{n,h})$. Similarly, the node n buying entity's marginal bid at hour h is integrated and denoted by $\beta^b_{n,h}(p^b_{n,h})$. We represent all the bilateral transactions by the set $\mathcal{W}=\{1, 2, \cdots, W\}$. Each bilateral transaction $w \in \mathcal{W}$ submits a transmission request indicating the *from* node, the *to* node and the desired transaction quantity t^w, which is limited by an upper bound $\bar{t}^w$. In addition, w also provides a function $\alpha^w(t^w)$ in its transmission request submission to indicate the maximum congestion charges willing to be borne as a function of the delivered transaction amount t^w. The IGO's process to determine the successful bids/offers of the pool players and the transmission services given to the bilateral transactions is stated as the GTSP (Liu and Gross 2004,2005). The IGO objective is to maximize the social welfare subject to the network constraints over a specified planning horizon $\mathcal{H}=\{h:1, 2, \cdots, H\}$, where h represents one hour of the planning horizon. Under the usual assumptions used in market studies, we state the GTSP as the mathematical program of the form

$$\max S_H = \sum_{h\in\mathcal{H}} \sum_{n=0}^{N} [\beta^b_{n,h}(p^b_{n,h}) - \beta^s_{n,h}(p^s_{n,h})] + \sum_{w=1}^{W} \alpha^w(t^w)$$

such that

$$g_{n,h}(p^s_{0,h}, p^s_{1,h}, \cdots, p^s_{n,h}; p^b_{0,h}, p^b_{1,h}, \cdots, p^b_{n,h}; t^1, t^2, \cdots, t^w) = 0 \leftrightarrow \lambda_{n,h}, \quad \forall n = 0, 1, \cdots, N, \ \forall h \in \mathcal{H}$$

$$h_{\ell,h}(p^s_{0,h}, p^s_{1,h}, \cdots, p^s_{n,h}; p^b_{0,h}, p^b_{1,h}, \cdots, p^b_{n,h}; t^1, t^2, \cdots, t^w) \le f^{\max}_\ell \leftrightarrow \mu_{\ell,h}, \quad \forall \ell = 1, 2, \cdots, L, \ \forall h \in \mathcal{H}$$

$$0 \le t^w \le \bar{t}^w, \quad \forall w = 1, 2, \cdots, W$$

$$0 \le p^s_{n,h} \le p^{s,\max}_n; \quad 0 \le p^b_{n,h} \le p^{b,\max}_n \tag{1}$$

where $p^s_{n,\ h}$=power injected at node n in hour h, limited by its maximum value, $p^{s,\ \max}_n$; $p^b_{n,\ h}$=power withdrawn at node n in hour h, limited by its maximum value, $p^{b,\ \max}_n$; $g_{n,\ h}(.)$=nodal real power flow balance equation at node n in hour h; and $h_{\ell,\ h}(.)$ =expression of the real power line flow in line ℓ in hour h. For every constraint set there is a corresponding set of dual variables: $\{\lambda_{n,\ h}: n=0,\ 1,\cdots,\ N;\ h=1,\cdots,\ H\}$ for the power flow balance equations and $\{\mu_{\ell,\ h}:\ell=1,\ 2,\cdots,\ L;\ h=1,\cdots,\ H\}$ for the real power line flows, respectively. Note that if we take the assumption of having a direct current (DC) power flow, we can group the constraints in Eq. (1) so that: $p^s_{n,\ h}-p^b_{n,\ h} = \sum_{n\neq m} B_{nm}\cdot(\delta_{n,\ h}-\delta_{m,\ h})\cdot L_{nm},\ \ \forall n\neq m;\ \ \forall h=1,\cdots H,$ where $B_{nm}=-1/X_{nm}$ is the susceptance of the line connecting nodes n and m, X_{nm} is the reactance of that line, $(\delta_{n,\ h}-\delta_{m,\ h})$ is the difference between the angles of nodes n and m in hour h, and L_{nm} is the number transmission assets connecting nodes n and m. Note that the line flow limits in Eq. (1) can be set as $|F_{nm,\ h}| =|B_{nm}\cdot(\delta_{n,\ h}-\delta_{m,\ h})|\leq F^{\max}_{nm}$, where $F_{nm,\ h}$ is the active power flow in the line connecting nodes n and m at hour h and $F^{\max}_{nm}$ corresponds to the maximum limit of the active power flow in a line connecting nodes n and m. The optimal solution of Eq. (1) determines the amount sold and bought by the pool players and the transmission services provided to the bilateral transactions. In addition, the dual variables $\lambda_{n,\ h}$ and $\mu_{\ell,\ h}$ provide the LMP at each node n at hour h, and the marginal values of a change in the line limit for each line ℓ at hour h, respectively. The GTSP in this way explicitly represents the impacts of the congestion management scheme. In general, this problem has two distinct aspects: the selection of the new transmission assets and the combination of the selected assets. Note that the problem formulation allows sequential decomposition of the investment problem. The formulation also lends itself nicely for scenario analysis, thereby providing a consistent basis to compare the impacts of different investments.

The second metric, the market efficiency loss (Caro-Ochoa 2003), is the reduction in the social welfare caused by congestion. In general, the market efficiency loss measures the value of the energy that is neither sold nor bought due to the presence of congestion in the system. The loss of market efficiency is known in the economic literature as the dead-weight loss (Varian 2002). To properly define it, we need to calculate first the social welfare without congestion $S_H|_u$, which is calculated as in Eq. (1), except that now there are no transmission constraints and the only requirement is that total supply matches total demand and that all bilateral contracts are fulfilled. We can express the market efficiency loss as

$$E=-(\ S_H|_c-\ S_H|_u) \tag{2}$$

where $S_H|_u$=total social welfare in the transmission-unconstrained market over the planning horizon and $S_H|_c$=social welfare in the constrained market. $S_H|_c$ is calculated as in Eq. (1), where the transmission constraints, real power flow balance, and real power flow limits are considered. Note that the market does no longer have a unique clearing price in presence of transmission constraints, as opposed to the unconstrained case. Such a situation arises because we explicitly consider the supply-demand balance at each of the buses of the system in the constrained case. Thus, each seller/buyer sells/buys energy at its nodal LMP. Nonzero LMP differences are an indication of the presence of transmission congestion. They also yield revenues for the IGO in the pool. The IGO collects the payments from the buyers and pays to the sellers for the energy traded in the pool. Without congestion, all LMPs are equal and the payments from the buyers equal the credits to the sellers. Thus, in this case, the social welfare is equal to the producer surplus plus the consumer surplus, only.

The third metric proposed is valuable when congestion occurs; in this case, total payments to the buyers exceed the payments from the sellers, and the IGO obtains revenues. These revenues, also called congestion rents, if aggregated for all nodes and all hours of the planning period are given by the expression

$$K=\sum_{h\in\mathcal{H}}\sum_{n=0}^{N}\lambda^*_{n,\ h}(p^{b*}_{n,\ h}-p^{s*}_{n,\ h}) \tag{3}$$

Note that social welfare does not provide complete information about how producers fare. Thus, we may use a metric to evaluate the performance of the producers alone—the producer surplus. The individual producer surplus $S^{S_n}_H$ of seller S_n measures the difference between the revenues that the seller receives for his clearing quantity at the market clearing price and those that he would receive at his offer prices for each hour. Aggregating all values over the entire planning period, $S^{S_n}_H$ for seller S_n located at node n is given by the expression

$$S^{S_n}_H=\sum_{h\in\mathcal{H}}[\lambda^*_{n,h}p^{s*}_{n,h}-\beta^s_{n,h}(p^{s*}_{n,h})] \tag{4}$$

The total aggregate producer surplus is the sum of the aggregate producer surpluses of all the sellers. Note that Eq. (4) does not include any contribution from bilateral transactions. We assume that a transaction that delivers t^w MW contributes an amount $\alpha^w(t^w)=B(t^w)-C(t^w)$ to social welfare, where $B(t^w)$ is the consumer benefit and $C(t^w)$ is the producer cost of the transaction (Liu and Gross 2004). However, both values are only known to the parties involved in the transaction. In addition the payments involved are also private, agreed on advance. So its contribution to the total producer surplus is not included.

Finally, we use a metric to evaluate the performance of consumers: the consumer surplus. Similarly to the previous subsection, the individual consumer surplus $S^{B_n}_H$ of consumer B_n measures the difference between the value of the energy purchased at the bid prices and that at the market clearing price for each hour. Aggregating all values over the entire planning period, $S^{B_n}_H$ for consumer B_n located at node n is given by the expression

$$S^{B_n}_H=\sum_{h\in\mathcal{H}}[\beta^b_{n,\ h}(p^{b*}_{n,\ h})-\lambda^*_{n,\ h}p^{b*}_{n,\ h}] \tag{5}$$

Total aggregate consumer surplus is the sum of the aggregate consumer surpluses of all the consumers. Again, Eq. (5) does not include any contribution from bilateral transactions, for the same reasons explained before.

Note that since transmission investments have distributional impacts over market agents, this fact creates conflicts of interest among market parties (Sauma and Oren 2007). Thus, the IGO should be aware of these potential conflicts of interests, and not only of the aggregate metrics presented here.

Case Studies

We illustrate our proposed framework with the IEEE 24-bus Reliability Test System (RTS) (Reliability Test System Task Force 1999). Since social welfare is equal to the producer surplus plus the consumer surplus plus the congestion rents (Caro-Ochoa 2003; Varian 2002), we also present the producer and consumer surpluses in our final results.

We consider that offers are at marginal cost considering a perfect competition scenario. We also consider a time horizon of one year, that is, a "target year." For this target year, we estimate the demand, the generation offers and the demand bids. Therefore, our model represents a "static transmission expansion planning" problem, since it considers a target year for which the net social welfare is maximized. For a detailed explanation of these concepts, please refer to Oliveira et al. (1995). In addition, Latorre et al. (2003) and Ramírez-Rosado and Gönen (1991) define some of the basic concepts regarding static transmission expansion planning.

We assume that the new lines will be operative for at least 25 years, thus a 25-year investment return period has been considered. A 10% interest discount rate is assumed as the cost of capital. With these values in mind, the value of the capital recovery factor can be calculated so that, for the next 25 years, the investment cost in new lines is yearly repaid at a rate of 11.02% of the total initial investment. This is also known as the annualized cost, as shown in Table 1. Finally, a DC model of the network is used and losses are not considered in the formulation.

IEEE 24-Bus RTS Case Study

Consider the IEEE 24-bus RTS depicted in Fig. 2 with the line data provided in Table 1. Initially, there are five disconnected corridors that tie the upper and the lower sections of the network. The line flow limits are modified with respect to Reliability Test System Task Force (1999) to allow line additions. Assume that the lines that are built in this case study are: one line in Corridors 3–24, one line in Corridors 10–11, and one line in Corridors 10–12. This solution could be also obtained, for example, with a transmission expansion model whose objective function was the aggregate social welfare minus the cost of expansion, subject to network constraints, over the period of study and disregarding bilateral contracts. However, the number of lines selected could also be different using another model. Since we are primarily interested in showing the effects of the changes in the conditions for bidding and in undertaking bilateral transactions under a set of selected reasonable line addition investments rather than the way in which the investors can profit from such investments, we do not consider profit making by an investor for a transmission asset investment, which is beyond the scope of this paper.

Bidding data are given in Tables 2 and 3, where we assume step-wise bidding functions. Each generator (demand) offer (bid) is composed of four (three) equally sized blocks, where the total quantity offer (bid) is also provided. To accurately describe possible bidding patterns of the studied year, we decompose it in four seasons, and for each season we select a representative working day and a weekend day, as shown in Fig. 3. We also assume that the actual size of the blocks offered and bid depends on the load pattern of every season of the year, as seen in Fig. 3. That means that, for example, 50% of the peak demand makes all the block sizes offered (bid) by the sellers (buyers) reach only 50% of their maximum values shown in Tables 2 and 3. We assume that the bids represent peak loading conditions and we apply the load curves to modify bid prices, bid quantities, or both values simultaneously. In addition, we allow two bilateral transactions (Galiana et al. 2002), as shown in Table 4. To define them, we set the corresponding sending and receiving nodes, power contracted and the willingness to pay function, following the formulation in Eq. (1). Note that in this case, the objective function optimizes the amount of contracts really delivered plus the social welfare contribution of the pool-based market. The time period of study is one year.

Table 1. IEEE 24-Bus RTS Line Data

From	To	X (pu)	Line flow limit (MW)	Annual cost (thousands of $)	Already built
1	2	0.0139	175	74	1
1	3	0.2120	175	10,692	1
1	5	0.0845	175	4,278	1
2	4	0.1267	175	6,414	1
2	6	0.1920	175	9,720	1
3	9	0.1190	175	6,024	1
3	24	0.0839	400	4,247	0
4	9	0.1037	175	5,250	1
5	10	0.0883	175	4,470	1
6	10	0.0605	175	3,063	1
7	8	0.0614	175	3,108	1
8	9	0.1651	175	8,358	1
8	10	0.1651	175	8,358	1
9	11	0.0839	400	4,247	0
9	12	0.0839	400	4,247	0
10	11	0.0839	400	4,247	0
10	12	0.0839	400	4,247	0
11	13	0.0476	500	2,410	1
11	14	0.0418	500	2,116	1
12	13	0.0476	500	2,410	1
12	23	0.0966	500	4,890	1
13	23	0.0865	500	4,379	1
14	16	0.0389	500	1,970	1
15	16	0.0173	500	876	1
15	21	0.0490	500	2,481	1
15	24	0.0519	500	2,627	1
16	17	0.0259	500	1,311	1
16	19	0.0231	500	1,170	1
17	18	0.0144	500	729	1
17	22	0.1053	500	5,331	1
18	21	0.0259	500	1,311	1
19	20	0.0396	500	2,005	1
20	23	0.0216	500	1,093	1
21	22	0.6780	500	3,432	1

To compare results with the defined metrics, we consider a comprehensive set of seven scenarios representing different bidding conditions.

- Scenario 1: demands quantity bids scaled by seasonal peak loads.
- Scenario 2: generators quantity offers scaled by seasonal peak loads.
- Scenario 3: both demands quantity bids and generators quantity offers scaled by seasonal peak loads.
- Scenario 4: demands price bids scaled by seasonal peak loads.
- Scenario 5: generators price offers scaled by seasonal peak loads.
- Scenario 6: both demands price bids and generators price offers scaled by seasonal peak loads.
- Scenario 7: both demands quantity and price bids and generators quantity and price offers scaled by seasonal peak loads.

For example, Scenario 1 means that the size of the blocks bid by the demands depend on the load pattern of every season of the

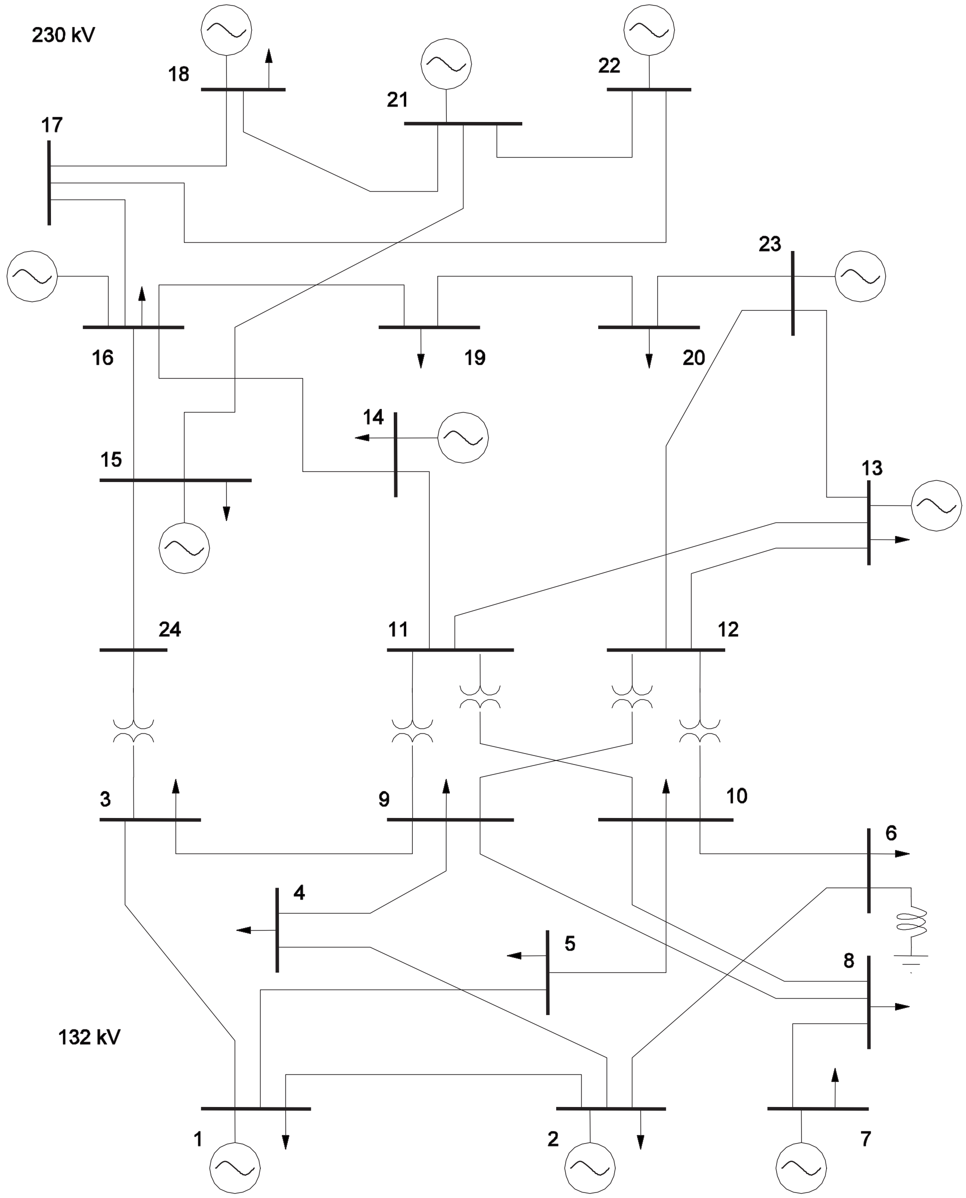

Fig. 2. IEEE 24-bus system topology

year, but the demands price bids and also the generators price and quantity offers remain at their peak values. Tables 5 and 6 present the results obtained for five representative metrics for the seven scenarios. The overall annualized cost of the transmission assets for all scenarios is equal to 12,741 thousands of $/year.

It can be observed that the highest values of social welfare and congestion rents correspond to Scenario 5, where the generators offer prices are scaled. This means that although the offer prices are low, there is a significant difference in nodal prices across the nodes and the amount of energy flowing is high. Low offer prices increase the demands surplus term of the social welfare but at the cost of heavy congestion, since the energy flowing in the network is considerable. The generators surplus term is also high, due to the significant amount of energy flowing in the network.

The highest value of the generators surplus term occurs in Scenario 2. In that scenario, all the generators scale their quantity offers. By doing this, they provoke high nodal prices and the generators surplus terms dramatically increases. This phenomenon is a typical oligopoly effect of reducing the quantities offered in a market increasing the average nodal price value.

The highest value of the demands surplus term occurs in Scenario 6. It is due to the effect of the scaling of the demands price bids on the congestion rents—it makes the congestion to disappear. However, this has a harmful effect on the generators surplus, since the combination of low prices and the small amount of energy flowing in the network makes this term very small.

Fig. 4 shows the mean nodal prices for Scenario 5, calculated as the weighted average of the representative days' nodal prices, with the weights being proportional to the number of days per year that the representative day accounts for. The effect of congestion on prices is depicted in Fig. 4. There are two clearly distinctive sets of prices: the higher values correspond to the more congested area of the network and the lower prices correspond to buses 17, 18, 21, and 22, placed in the left upper corner of the network (see Fig. 2). Fig. 5 shows the mean nodal prices for Scenario 7, in which there is no congestion in the network.

Table 2. IEEE 24-Bus RTS: Generators Offers

Node	Generators: Name	MWh offer	Offer price ($/MWh)
1	S_1	250	15, 18.8, 22.5, 26.3
2	S_2	250	13, 16.3, 19.5, 22.8
3	—		
4	—		
5	—		
6	—		
7	S_3	220	15, 18.8, 22.5, 26.3
8	—		
9	—		
10	—		
11	—		
12	—		
13	S_4	100	15, 18.8, 22.5, 26.3
14	S_5	100	14, 17.5, 21, 24.5
15	S_6	100	16, 20, 24, 28,
16	S_7	100	15, 18.8, 22.5, 26.3
17	—		
18	S_8	100	13, 16.3, 19.5, 22.8
19	—		
20	—		
21	S_9	100	14, 17.5, 21, 24.5
22	S_{10}	300	15, 18.8, 22.5, 26.3
23	S_{11}	200	15, 18.8, 22.5, 26.3
24	—		

Table 3. IEEE 24-Bus RTS: Demands Bids

Node	Demands: Name	MWh Bid	Bid price ($/MWh)
1	B_1	62	39, 36.4, 33.8
2	B_2	70	44.2, 41.6, 39
3	B_3	48	26, 20.8, 18.2
4	B_4	125	39, 36.4, 33.8
5	B_5	187	44.2, 41.6, 39
6	B_6	62	39, 36.4, 33.8
7	B_7	187	44.2, 41.6, 39
8	B_8	187	26, 20.8, 18.2
9	B_9	125	39, 36.4, 33.8
10	B_{10}	187	44.2, 41.6, 39
11	—		
12	—		
13	B_{11}	62	39, 36.4, 33.8
14	B_{12}	70	44.2, 41.6, 39
15	B_{13}	31	26, 20.8, 18.2
16	B_{14}	83	39, 36.4, 33.8
17	—		
18	B_{15}	148	44.2, 41.6, 39
19	B_{16}	62	39, 36.4, 33.8
20	B_{17}	226	44.2, 41.6, 39
21	—		
22	—		
23	—		
24	—		

To analyze the effect of bilateral contracts on the welfare metrics we set the two contracts shown in Table 4. We assume $\alpha^w(t^w)=\bar{\alpha}^w t^w$, $t^w \in [0,\bar{t}^w]$, so that $\bar{\alpha}^w$ acts as a price cap on the transmission price for the transaction. Note that bilateral contracts add an extra term to the social welfare that can be expressed as a contract surplus $[\alpha^w(t^w)$—the willingness to pay—minus the congestion rents paid by the transaction] plus the congestion rents associated to the transaction.

It is not very meaningful to compare results in terms of loss of efficiency and social welfare with and without contracts because the bilateral transactions change the system conditions. Therefore, we set two different models to study the effect of contracts. The first model assumes that there is an unlimited willingness to pay for the bilateral contracts. In this case, the contracts are always fulfilled and the line flow limits in Eq. (1), $f_\ell^{\max}$, are reduced by the MW amount due to the contracts apportioned to the lines, using power transfer distribution factors (Liu and Gross 2004). The second model is exactly as in Eqs. (1) and (2). Note that it can be proven that the social welfare is higher in the latter model, since the social welfare contributions of the pool-based market and the bilateral transactions are optimized simultaneously, not sequentially. Likewise, the loss of efficiency is always smaller in the latter model. A detailed proof is provided in Liu and Gross (2004). The results for Scenario 5 are shown in Table 7, where the two models are compared.

As expected, social welfare is bigger with the optimized bilateral contracts model and the loss of efficiency term is also smaller. Congestion rents values are higher in Model 1 because

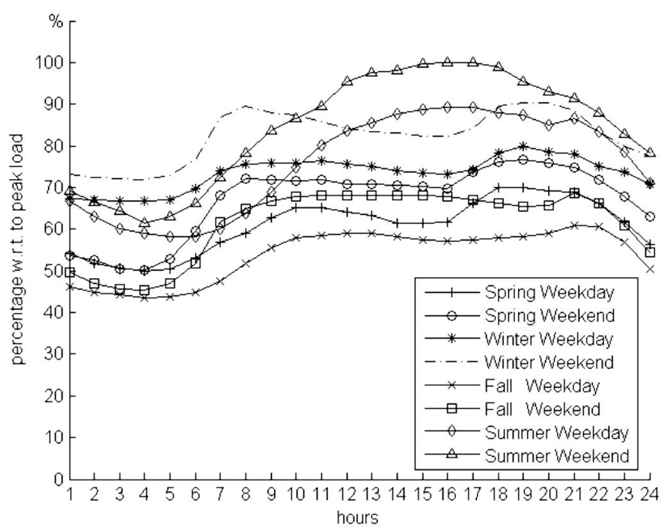

Fig. 3. Load curves for each of the representative days of the year

Table 4. IEEE 24-Bus RTS: Bilateral Contracts Data

Transaction number	From bus	To bus	Maximum size (MW)	$\bar{\alpha}^w$ ($/MW)
1	17	10	120	12
2	18	11	150	15

Table 5. IEEE 24-Bus RTS: Social Welfare, Loss of Efficiency, and Congestion Rents for the Seven Bidding Scenarios (Thousands of $/Year)

Scenario	Preexpansion social welfare	Social welfare	Loss of efficiency	Congestion rents
1	222,286	233,970	24.61	808
2	221,260	236,061	94.32	2,193
3	192,841	213,335	0.00	0.00
4	184,682	199,255	68.90	551
5	305,538	346,108	1,153	17,986
6	225,992	251,224	0.00	0.00
7	165,003	182,552	0.00	0.00

the system is more congested due to the compulsory fulfillment of the contracts that reduces the line flow limits for the pool-based market. It can be observed that the generators surplus term is smaller in Model 2 but the demands surplus term is bigger. This is also due to the lack of congestion in Model 2.

We can also see the effect of contracting looking at the mean nodal prices, as shown in Figs. 6 and 7, for Model 1 and Model 2, respectively. Fig. 6 shows that the four uncongested nodes have even lower prices than in Fig. 4, but the rest spreads across a wide range of values. In Fig. 7, the price difference between the congested and uncongested areas is even wider but it keeps the same shape as compared to Fig. 4. Note that in Model 2, the MW flow due to the contracts goes from the uncongested area to the congested area, widening the gap between congested and uncongested nodal prices. This effect is not clearly observed in Model 1 since there is no simultaneous consideration of contracts and pool in the optimization of social welfare.

We note that in all the case studies presented, the social welfare increase is the metric that is the determinant of the expansion

Table 6. IEEE 24-Bus RTS: Generators and Demands Surplus for the Seven Bidding Scenarios (Thousands of $/Year)

Scenario	Generators surplus	Demands surplus
1	58,144	175,018
2	179,682	54,186
3	71,374	141,961
4	75,006	123,697
5	117,227	210,896
6	34,537	216,687
7	28,913	153,639

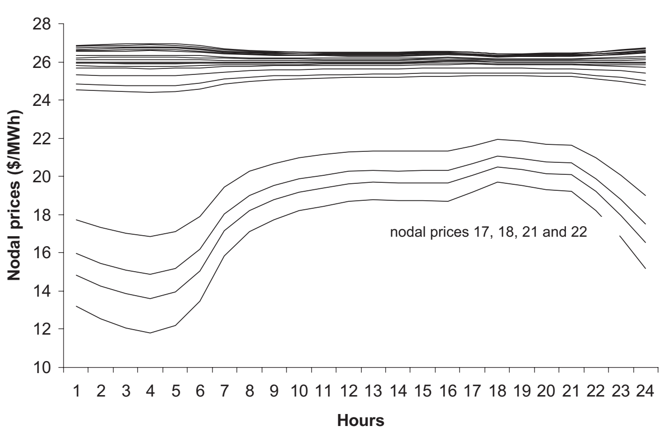

Fig. 4. IEEE 24-bus RTS mean nodal prices for Scenario 5

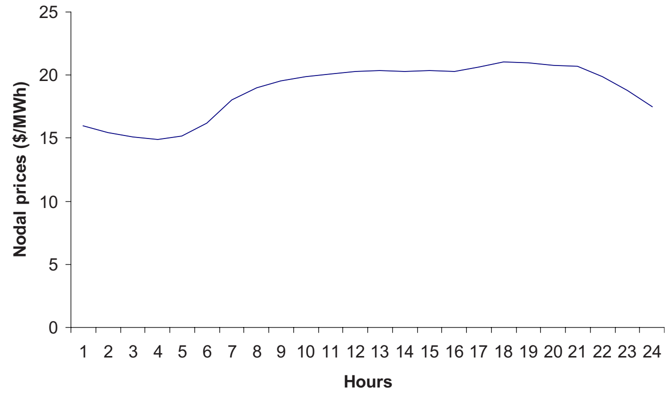

Fig. 5. IEEE 24-bus RTS mean nodal prices for Scenario 7

decision, notwithstanding that there are postexpansion winners and losers among the players. This fact makes very difficult to overcome possible vetoes by the participants who are negatively impacted by the expansion. This may only be possible under some type of expost agreement or a cooperative game theory approach (Ruiz and Contreras 2007).

The software used to program the simulations of all the case studies is CPLEX under GAMS (Brooke et al. 2003). Running times are about 2 min of CPU in a multiprocessor Linux server at 1.6 GHz.

Concluding Remarks

The writers have presented the development of a general framework to study the problem of transmission investment in the new

Table 7. IEEE 24-Bus RTS Annual Economic Metrics (Thousands of $/Year) in Scenario 5 with and without Bilateral Contracts

	No bilateral contracts	Model 1: bilateral contracts	Model 2: optimized bilateral contracts
Social welfare	346,108	328,273	348,006
Loss of efficiency	1,153	46,645	31,491
Congestion rents	17,986	53,184	26,632
Generators surplus	117,227	154,284	136,859
Demands surplus	210,896	93,148	180,324
Bilateral contracts	—	27,657	4,191

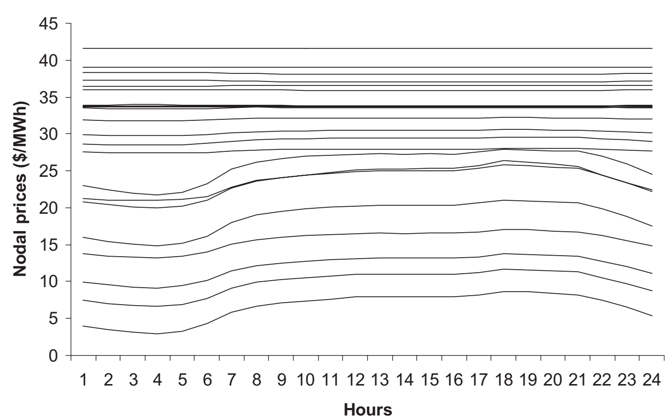

Fig. 6. IEEE 24-bus RTS mean nodal prices in Scenario 5 with bilateral contracts: Model 1

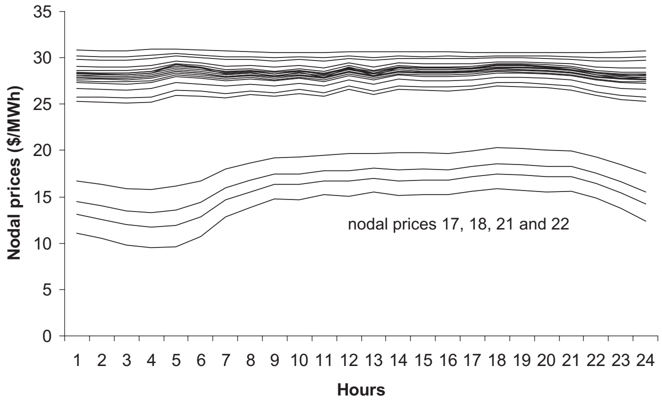

Fig. 7. IEEE 24-bus RTS mean nodal prices in Scenario 5 with optimized bilateral contracts: Model 2

competitive arena. Specifically, the writers have shown a new investment layer to use a multilayered analytic framework for the analysis of transmission investment issues. This new additional layer allows the sequential decomposition of the problem and the easy incorporation of scenario analysis. As such, the framework constitutes a powerful policy analysis tool. The writers have introduced appropriate metrics to evaluate the impacts of a transmission asset investment. The writers have presented illustrative case studies to study the effect of different bidding scenarios and bilateral contracting arrangements in the proposed metrics. Future research will address the development of effective incentives for transmission investment over a longer-term period.

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