A FRAMEWORK FOR THE ANALYSIS OF TRANSMISSION PLANNING IN THE MARKET ENVIRONMENT

Javier Contreras
E.T.S. de Ingenieros Industriales
Universidad de Castilla – La Mancha
13071 Ciudad Real, Spain
Javier.Contreras@uclm.es

Verónica Bósquez   George Gross
Department of Electrical and Computer Engineering
University of Illinois at Urbana-Champaign
61801 Urbana, IL, USA
bosquez@uiuc.edu   gross@uiuc.edu

Abstract − The need for investment in the improvement and expansion of the grid and for maintaining the existing network has not been met in the competitive environment. Under the new paradigm, the economic signals resulting from the daily markets, such as locational marginal prices, congestion metrics and others, need to be explicitly considered together with the economics of investment in new assets. This paper presents a framework for the analysis of issues in the planning and investment of transmission in the competitive environment. We construct the framework as an extension of a framework developed for congestion analysis by adding a new layer for transmission expansion/investment issues. This extension requires the development of appropriate metrics to allow the evaluation of measures needed for the planning horizon. The principal notion is to evaluate the relevant metrics with and without the transmission asset investment(s). We apply the framework to investigate transmission expansion scenarios from the Independent Grid Operator (*IGO*) point of view. We present representative results to illustrate the capability of the decision support framework that we propose.

Keywords: Transmission expansion planning, network investment, social welfare, congestion management, locational marginal pricing

1   INTRODUCTION

In the past, both the operating and the planning aspects of the electric network were in the hands of centralized entities organized in a vertically-integrated structure. However, the unbundling of the electricity business has presented new challenges that the restructured industry must face. A key aspect of restructuring is the creation of new structures, such as the Independent Grid Operator (*IGO*), and, in certain cases, the separation of the ownership from the control and operation of the network. A salient characteristic of the new structure is the more widely present decentralized decision making. The restructuring of the electricity industry has resulted in the advent of many new players, such as brokers, marketers and independent power producers. One critical outcome of the large number of players and the increasing number of transactions is the more frequent stressing of the transmission grid due to the creation of congestion situations. One of the main reasons for the increasing frequency of congestion is that the transmission network investments have not kept pace with the increasing demand for transmission services [1]. In the short-term, the only way to deal with the congestion problem is through effective congestion management, i.e., through deploying efficient procedures to coordinate all participants' actions to maintain system reliability [2]. But congestion has rather serious long-term market effects, and consequently impacts the decisions regarding new investments in both transmission and generation [3][4].

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 entailing losses of market efficiency. Also, congestion facilitates the opportunities to exercise market power through gaming by some players to increase their profits. Thus, the study of congestion needs metrics to meaningfully measure these impacts in terms of energy and money. In the planning of new transmission asset additions, to reduce congestion, the objectives of market efficiency increase and social welfare maximization may compete with those of the individual players and the investors. Each market player may be differently affected, faring better or worse as a result of congestion relief with a new investment leading to the modification of the existing system.

Network expansion may be viewed as a very complex multi-period and multi-objective optimization problem [5]-[8]. Its nonlinear nature and the inherent uncertainty of future developments constitute major complications. Its solution is very difficult, even in the earlier centralized environment. In the past, 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 economic signals that result from the daily operations of the hourly electric markets (prices, congestion metrics, surpluses) need to be considered together with the economics of investment in new facilities in an environment of regulatory and legislative uncertainty and with the operational control of the facilities being vested in hands different than the ownership.

The multiple facets of the transmission expansion/improvement problem pose highly demanding challenges. The multiplicity and variety of players – existing owners, investors, regulators, the *IGO*, and the broad variety of transmission customers and their specific objectives – represent a key complication. Another one is the long time horizon together with the sequence of appropriate decisions. The imperfect nature of the electricity markets together with the opportunities for the possible exercise of market power by certain players constitute yet another major complicating factor. The short-run marginal costing information obtained from the hourly *locational marginal prices* (*LMP*s) does provide congestion signals but needs to be effectively "translated" into long-run marginal cost information for the investment decisions. The effective integration of the *FTR* or financial transmission rights [9] pose an added level of complication. Underlying all these factors are the wide ranges of uncertainty in the actions of market players, the transmission investments to be undertaken, the transmission *available transfer capability or ATC* [10] and the associated *FTR* [11]-[15], whose combined effect makes this problem inherently stochastic in nature.

This paper proposes an analytic framework for the transmission investment problem in the competitive environment to address the multiple challenges outlined above. This framework is an extension of the one constructed for congestion analysis [11][12]. The next section provides the description of the multi-layered analytic framework that has the capability to capture the various aspects of the transmission investment issues. We present the definition of the relevant metrics to assess transmission asset investment(s) from the *IGO*, generation and demand points of view in section 3. We apply our analytic framework to study several transmission expansion scenarios in various systems and report some representative simulation results to illustrate the capability of the proposed decision support framework.

2 THE ANALYTIC FRAMEWORK

We develop a general framework capable of dealing with the complexity of issues in transmission investment in competitive electricity markets by extending the analytical three-layer framework developed in [11][12]. We add an investment layer for the analysis of expansion problems and construct the appropriate interconnections with the three layers. The extended framework thus 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 [11]. 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 conges-

tion 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 [12], and the *IGO* decision making process. This process requires the formulation of the so-called generalized transmission scheduling problem (*GTSP*) [12] to determine the hourly market outcomes of the players' sales and purchases, the transmission schedules and the *LMP*s at all grid nodes. The models of the *FTR* and the *FTR* markets constitute the financial market layer.

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. Without loss of generality, we assume a single seller and a single buyer at each node $n = 0, 1, \cdots, N$, where $\mathcal{L}$ is the set of lines and transformers that connect the buses of the network.

The node n selling entity's marginal offer is integrated and denoted by $\beta_n^s(p_n^s)$. Similarly, the node n buying entity's marginal bid is integrated and denoted by $\beta_n^b(p_n^b)$. We represent all the bilateral transactions by the set $\mathcal{W} \triangleq \{1, 2, \cdots, W\}$. Each bilateral transaction $w \in \mathcal{W}$ submits a transmission request indicating the *from* node, the *to* node and the desired transaction quantity. 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*. The *IGO* objective is to maximize the *social welfare* subject to the network constraints. Under the usual assumptions used in market studies, we state the *GTSP* as the mathematical program of the form

$$max \ \mathscr{S} = \sum_{n=0}^{N} \left[\beta_n^b(p_n^b) - \beta_n^s(p_n^s) \right] + \sum_{w=1}^{W} \alpha^w(t^w)$$

$s.t.$

$$g_n \left(p_0^s, p_1^s, \cdots, p_n^s; p_0^b, p_1^b, \cdots, p_n^b; t^1, t^2, \cdots t^w \right) = 0$$
$$n = 0, 1, \cdots, N \quad (1)$$
$$h_\ell \left(p_0^s, p_1^s, \cdots, p_n^s; p_0^b, p_1^b, \cdots, p_n^b; t^1, t^2, \cdots t^w \right) \le f_\ell^{max}$$
$$\ell \in \mathcal{L}$$

where, $g_n(\bullet)$ is the nodal real power flow balance equation at node n and $h_\ell(\bullet)$ is the expression of the real power line flow in line ℓ. For every constraint set there is a corresponding set of dual variables: $\{\mu_n\}$ for the power flow balance equations, and $\{\lambda_\ell\}$ for the real power line flows, respectively. The optimal solution of (1) determines the amount sold and bought by the pool players and the transmission services provided to
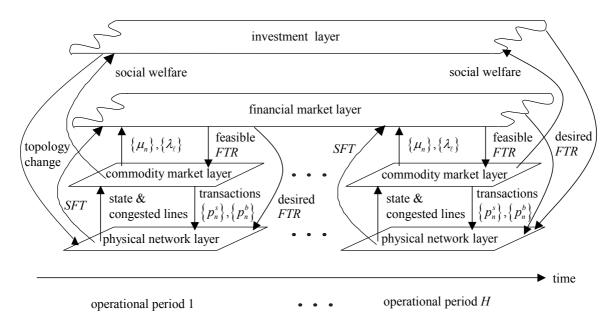
Figure 1: The four-layer framework structure used in the analysis of transmission investment.

the bilateral transactions. In addition, the dual variables μ_n and λ_ℓ provide the *LMP*s at each node n and the marginal values of a change in the line limit for each line ℓ, respectively. The *GTSP* in this way explicitly represents the impacts of the congestion management scheme. The *GTSP* solution also provides essential information together with that from the 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 detailed description of the interactions is given in [11].

The proposed addition of a fourth layer to this three-layer framework 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 are 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 several years. The total social welfare $\mathcal{S}_H$ for a combination of the transmission assets over the H-hour planning horizon is

$$\mathcal{S}_H = \sum_{h=1}^{H} \mathcal{S}_h \qquad (2)$$

where $\mathcal{S}_h$ is the optimal social welfare for hour h, available from the *GTSP* solution in (1) from the market layer. The combination of assets that yields the maximum social welfare is selected. Note that the optimal combination of investments also provides the maximum reduction of market loss of efficiency. Thus, by getting the maximum social welfare (or minimum market efficiency loss) congestion is also minimized. If the players are also engaged in some type of contracts, like *FTR* for

example, this affects the way they bid every hour, so it can be easily incorporated into the model.

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 illustrated in Fig. 1. We start 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 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 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 [11] using the hourly network layer information. The outcomes of the financial markets may impact the customers' bidding behavior in the commodity markets, which become the *GTSP* inputs. 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 *LMP*s determined by the *GTSP* as the optimal dual variables provide the basis for the financial behavior in the commodity markets, which become the *GTSP* inputs. 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 *LMP*s determined by the *GTSP* as the optimal dual variables provide the basis for the financial market layer to evaluate the *FTR* payoffs.

3 RELEVANT METRICS FOR TRANSMISSION EXPANSION

In order to assess the potential benefit of a new transmission asset investment it is necessary to define the metrics that will measure that improvement. The metrics are calculated considering all possible points of view: *IGO*, producers, and consumers. By slight abuse of notation we assume that all nodal values are hourly values.

3.1 IGO Metrics

There are three metrics that the *IGO* can use to determine whether an investment in transmission assets is beneficial to the network as a whole: *social welfare, loss of efficiency* and *congestion rents*.

The social welfare is an important metric since it measures the overall impacts on both sellers and buyers in pool-based markets. The double auction market mechanism has as objective the maximization of the social welfare, so as to determine the maximum net benefits for society. If we also include all bilateral transactions 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, as expressed in (1). Note that to ensure the reliability of the network the various transmission constraints must be considered.

To calculate the aggregate value of the social welfare we assume that hourly data in terms of bids, offers and bilateral transactions are known. Based on that, we calculate the total social welfare, as expressed in (2), for an investment time horizon that can span several years. To determine the best investment, we compare total social welfare with and without transmission assets. As mentioned in the previous section, the problem has two distinct facets: selection of the available transmission assets and combination of selected assets. The combination of resources that yields the maximum social welfare is selected and the same process can be run in a multi-year framework by repeating this procedure. Note that (2) involves the possibility of sequential decomposition of the investment problem. That is a key characteristic of our investment modeling, since we can decompose the problem hour-by-hour to obtain the best overall solution for a whole year, for example. The formulation also allows for scenario analysis, such that different values of social welfare can be obtained, providing an uniform basis to compare.

The other relevant metric to the *IGO* is the market efficiency loss. The *market efficiency loss* [16] is the reduction in the social welfare caused by congestion:

$$\mathcal{E} \triangleq -(\mathcal{S}_H|_c - \mathcal{S}_H|_u) \tag{3}$$

where $\mathcal{S}_H|_u$ denotes the total social welfare in the transmission-unconstrained market over the H period planning horizon and $\mathcal{S}_H|_c$ denotes the social welfare in the constrained market. $\mathcal{S}_H|_c$ is calculated as in (2), where the transmission constraints, real power flow balance and real power flow limits, are provided in (1).

$\mathcal{S}_H|_u$ is calculated as in (2), except that there are no transmission constraints from (1), and the only requirement is that total supply matches total demand in the system in the pool and that all bilateral contracts are fulfilled, as shown in (4).

$$max\ \mathcal{S} = \sum_{n=0}^{N}\left[\beta_n^b(p_n^b) - \beta_n^s(p_n^s)\right] + \sum_{w=1}^{W}\alpha^w(t^w)$$

$$s.t. \tag{4}$$

$$\sum_{n=0}^{N} p_n^s = \sum_{n=0}^{N} p_n^b \ \leftrightarrow\ \mu$$

From (4), total social welfare is calculated now as in (2). We assume that the bids, offers and bilateral contracts are the same both in the unconstrained and the constrained cases to generate comparable results. Note that with the transmission constraints considered, the market does no longer have a unique clearing price, as in 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 congestions, all *LMP*s 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. When congestion occurs, the buyer's total payments exceed the payments to 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:

$$\mathcal{K} = \sum_{h=1}^{H}\sum_{n=0}^{N} \mu_n^*\ (p_n^{b*} - p_n^{s*}). \tag{5}$$

Now the social welfare is equal to the producer surplus plus the consumer surplus plus the congestion rents [16]. Clearly, the congestion rents, related to *LMP* differences, are a metric of interest both for the *IGO* and *FTR* holders.

3.2 Producer Metrics

Social welfare does not provide complete information about how producers fare. Thus, we use a metric to evaluate the performance of the producers: the *producer surplus*. We also evaluate the impact of the transmission constraints in the cost of the producers: *redispatch costs*.

As defined in the previous section, we assume that the node n selling entity's marginal offer is integrated and denoted by $\beta_n^s(p_n^s)$, μ_n^* is the clearing market price (*LMP*) at bus n and p_n^{s*} is the offer value that optimizes total social welfare in (1). The individual *producer surplus* $\mathcal{S}_h^{S_n}$ 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. Ag-

gregating all values over the entire planning period, $\mathscr{S}_H^{S_n}$ for seller S_n located at node n is given by the expression:

$$\mathscr{S}_H^{S_n} = \sum_{h=1}^{H} \mathscr{S}_h^{S_n} = \sum_{h=1}^{H}[\mu_n^* p_n^{s*} - \beta_n^s(p_n^{s*})]. \qquad (6)$$

The total aggregate producer's surplus is the sum of the aggregate producer surpluses of all the sellers. Note that (6) does not include any contribution from bilateral transactions. We assume that a transaction that delivers t^w MW contributes an amount $\alpha^w(t^w) = \mathscr{B}(t^w) - \mathscr{C}(t^w)$ to social welfare, where $\mathscr{B}(t^w)$ is the consumer benefit and $\mathscr{C}(t^w)$ is the producer cost of the transaction [11]. 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.

The individual *redispatch costs* of seller S_n located at node n are given by the difference between the costs of the energy $[p_n^{s*}]|_c$ produced for the constrained market when social welfare is optimized in (1) and the corresponding costs for the supply of the same energy in the unconstrained market; all values are calculated for each hour [16]. We denote the total costs of $[p_n^{s*}]|_c$ as $\mathscr{C}_c([p_n^{s*}]|_c)$ and the ones that would be incurred in the unconstrained market for the same amount of energy as $\mathscr{C}_u([p_n^{s*}]|_c)$. Aggregating all these values over the entire planning period, the redispatch costs $\mathscr{C}_{r,H}^{S_n}$ for producer S_n are given by

$$\mathscr{C}_{r,H}^{S_n} = \sum_{h=1}^{H} \mathscr{C}_{r,h}^{S_n} = \sum_{h=1}^{H}[\mathscr{C}_c([p_n^{s*}]|_c) - \mathscr{C}_u([p_n^{s*}]|_c)]. \qquad (7)$$

Total aggregate redispatch costs are the sum of all the aggregate redispatch costs of all the producers. Note that the redispatch costs are incurred when the rescheduling of the supply-side resources becomes necessary to avoid violations of the transmission constraints. Since redispatch power is nonnegative, redispatch costs are also nonnegative.

3.3 Consumer Metrics

We use a metric to evaluate the performance of consumers: the *consumer surplus*. We also evaluate the impact of the transmission constraints in the payments of the consumers: *load payment costs*.

Similarly to the previous subsection, the individual *consumer surplus* $\mathscr{S}_h^{B_n}$ 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, $\mathscr{S}_H^{B_n}$ for consumer B_n located at node n is given by the expression:

$$\mathscr{S}_H^{B_n} = \sum_{h=1}^{H} \mathscr{S}_h^{B_n} = \sum_{h=1}^{H}[\beta_n^b(p_n^{b*}) - \mu_n^* p_n^{b*}]. \qquad (8)$$

Total aggregate consumer's surplus is the sum of the aggregate consumer surpluses of all the consumers. Again, (8) does not include any contribution from bilat-

eral transactions, for the same reasons explained in the previous subsection.

The individual *load payment costs* of consumer B_n located at node n are given by the difference between the payments made by the consumer of the energy $[p_n^{b*}]|_c$ produced for the constrained market when social welfare is optimized in (1) and the corresponding payments for the same energy in the unconstrained market; all values are calculated for each hour. We denote the total load payment costs of $[p_n^{b*}]|_c$ as $\mathscr{L}_c([p_n^{b*}]|_c)$ and the ones that would be incurred in the unconstrained market for the same amount of energy as $\mathscr{L}_u([p_n^{b*}]|_c)$. Aggregating all these values over the entire planning period, the load payment costs $\mathscr{L}_{p,H}^{B_n}$ for consumer B_n are given by

$$\mathscr{L}_{p,H}^{B_n} = \sum_{h=1}^{H} \mathscr{L}_{p,h}^{B_n} = \sum_{h=1}^{H}[\mathscr{L}_c([p_n^{b*}]|_c) - \mathscr{L}_u([p_n^{b*}]|_c)]. \qquad (9)$$

Total aggregate load payment costs are the sum of all the aggregate load payment costs of all the consumers. Note that the load payment costs per consumer per hour are also equal to $\mu_n^* p_n^{b*}$ and $\sum_{n=0}^{N} p_n^s = \sum_{n=0}^{N} p_n^b$ in a lossless network, thus the same amount of energy can be used to calculate the redispatch costs and the load payment costs.

4 SIMULATION STUDIES

For illustrative purposes we provide a representative example: the IEEE 7-bus case from the Reliability Test System (RTS) [17], as shown in Fig. 2. Generator and demand bidding data are taken from [16].
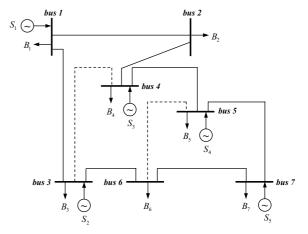

Figure 2: IEEE 7-bus RTS topology.

In this system, there are three possible types of line additions: line 3-4 (between buses 3 and 4), line 5-6, or a combination of both lines. For the sake of simplicity we assume that there are no bilateral transactions, and the bids and offers remain equal for all combinations of line additions. We use quadratic expressions for the cost and benefit functions for each player. In general, we use for a seller S_i the form

$$\mathscr{C}^{S_i}(P^{S_i}) = \beta^{S_i} P^{S_i} + 0.5\gamma^{S_i}(P^{S_i})^2, \ i = 1, \ldots, M^S, \qquad (10)$$

and for a buyer B_j the expression

$$\mathscr{B}^{B_j}(P^{B_j}) = \beta^{B_j} P^{B_j} - 0.5\gamma^{B_j}(P^{B_j})^2, \ j = 1, \ \ldots, \ M^B. \quad (11)$$

It follows, then, that the offer function of seller S_i has the form

$$\sigma^{S_i}(P^{S_i}) = \beta^{S_i} + \gamma^{S_i}P^{S_i}, \quad i = 1, 2, \ \ldots, \ M^S, \quad (12)$$

and the bid function of buyer B_j is given by

$$\nu^{B_j}(P^{B_j}) = \beta^{B_j} - \gamma^{B_j}P^{B_j}, \quad j = 1, 2, \ \ldots, \ M^B. \quad (13)$$

M^S and M^B are the number of units belonging to a seller and a buyer, respectively. We refer to β^{S_i} and γ^{S_i} (β^{B_j} and γ^{B_j}) as the offer (bid) parameters of seller S_i (buyer B_j).

With respect to the planning horizon, we assume that it is one year. To accurately describe possible bidding patterns of that particular year, we decompose it in four seasons, and for each season we select a representative working day and a weekend day. We also assume that only the offer and bid intercepts, β^{S_i} and β^{B_j}, change due to seasonal demand patterns, i.e., if the demand increases (decreases), both intercepts increase (decrease). Due to space limitations, we cannot show here all the bidding and demand patterns.

Once defined all the parameters of the problem, we study what the resulting metrics are in four possible scenarios: no line additions, addition of line 3-4, addition of line 5-6, and addition of lines 3-4 and 5-6 simultaneously. Tables 1, 2, and 3 show the aggregate metrics for the *IGO*, producers, and consumers, respectively. Fig. 3 shows the social welfare, the producer surplus, the consumer surplus, and the congestion rents for a typical weekday of the summer season in the four scenarios. Fig. 4 depicts the *LMP*s for the same days in the four scenarios. Fig. 5 presents the nodal price differences for the same days and scenarios.

From the figures and tables it can be observed that the best overall solution takes place when both lines 3-4 and 5-6 are added, i.e. scenario 4. Nevertheless, it is in scenario 2 where the costs of generation and load payments are the lowest, and also where the highest congestion rents occur. It is also remarkable the flattening of the nodal price differences in scenarios 3 and 4, which are related to the alleviation of congestion during the evening peak demand hours in the summer. *LMP*s are also more grouped and have lower average values in scenarios 3 and 4, as expected.

scenario	social welfare	loss of efficiency	congestion rents
1	305101.73	6679.58	7664.69
2	308204.19	3577.12	**8715.52**
3	305975.03	5806.28	4939.40
4	**308799.57**	**2981.74**	5179.23

Table 1: *IGO* annual economic metrics for each scenario (1000s of $/year).

scenario	producer surplus	redispatch costs	generation costs
1	27363.09	8858.78	233837.78
2	27503.96	**4076.11**	**228935.48**
3	28706.49	10503.31	235332.01
4	**30005.20**	5664.01	230434.84

Table 2: Aggregate producers annual economic metrics for each scenario (1000s of $/year).

scenario	consumer surplus	load payment costs	load payments
1	270073.95	5326.32	268865.55
2	271984.71	**1564.14**	**265154.95**
3	272329.14	5407.56	268977.90
4	**273615.14**	2032.60	265619.26

Table 3: Aggregate consumers annual economic metrics for each scenario (1000s of $/year).
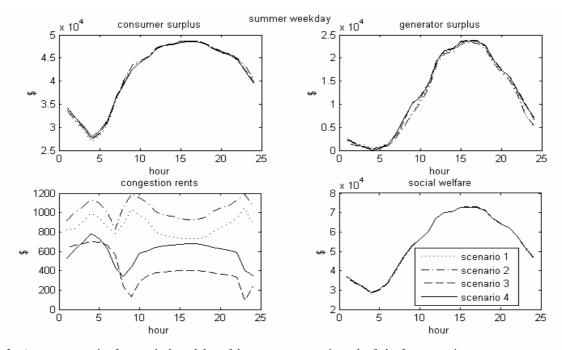

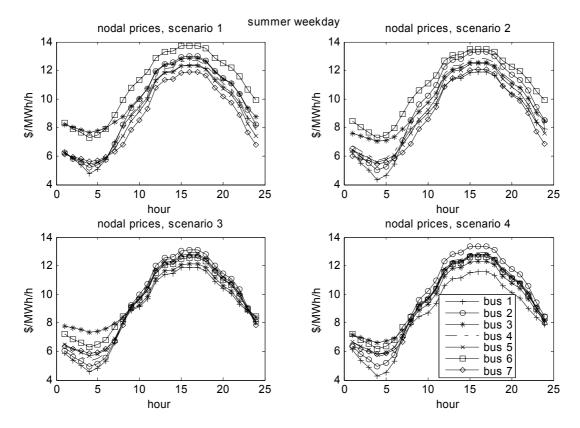**Figure 3:** Aggregate metrics for a typical weekday of the summer season in each of the four scenarios.

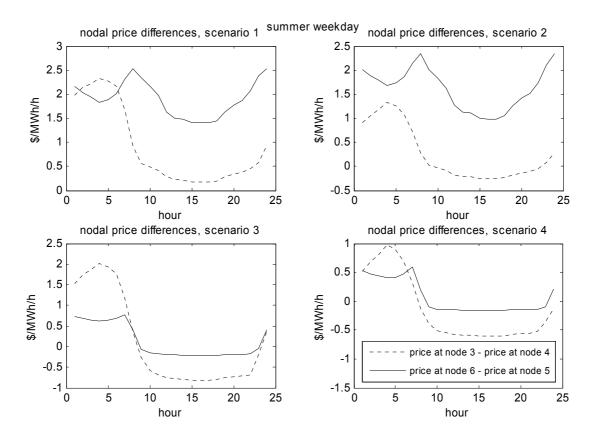**Figure 4:** *LMP*s for a typical weekday of the summer season in the four scenarios.

Figure 5: Nodal price differences for a typical weekday of the summer season in the four scenarios.

CONCLUSION

We have constructed a general framework to study the problem of transmission investment in the new competitive arena. Specifically, we have shown a multi-layered analytic framework with an investment layer. This investment layer allows for sequential decomposition of the problem and scenario analysis, making it a powerful policy analysis tool. We have presented an illustrative case study to select the best expansion alternatives with our decision-aid tool. This sample study is effective in illustrating the strong capability of the proposed framework for the study of transmission expansion/improvement decisions. The extension of the concepts discussed here to the individual investor problem will be reported in future papers.

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