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Proactive Transmission Investment in Competitive Power Systems

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***Abstract*—We formulate a three-period model for studying how the exercise of local market power by generation firms affects the equilibrium investment between the generation and the transmission sectors. Using a 30-bus network example, we compare the transmission investment decisions made by a "proactive" network planner (who proactively plans transmission investments to induce a more socially-efficient equilibrium of generation investments) with both those made by an integrated-resources planner (who jointly plans generation and transmission expansions) and those made by a "reactive" network planner (who plans transmission investments only considering the currently installed generation capacities). We show that, although a proactive network planner cannot do better (in terms of social welfare) than an integrated-resources planner, it can recoup some of the lost welfare due to the separation of generation and transmission planning by proactively expanding transmission capacity. Conversely, a reactive network planner, who ignores the interrelationship between the transmission and the generation investments, foregoes this opportunity.**

***Index Terms*—Cournot-Nash equilibrium; market power; mathematical programming; mathematical program with equilibrium constraints; network expansion planning; power system economics.**

I. INTRODUCTION

DURING the past decade, many countries – including the US – restructured their electric power industries, which essentially changed from one dominated by vertically integrated monopolies (where the generation and the transmission sectors were jointly planned and operated) to a deregulated industry (where generation and transmission are both planned and operated by different entities). The fact that generation and transmission expansions are planned by different entities creates conflicts of interests among these institutions, which generally leads to social losses. Since the existing US electricity transmission network was designed to serve a vertically integrated industry that no longer exists, one of the main challenges of the deregulated system is to create market rules that allow the upgrades needed to ensure the reliability of the system at the minimum social cost.

Because of the unique nature of electricity, there are inherent operational and investment complementarities and substitutabilities between the generation and the transmission sectors. A vertically integrated monopolist can incorporate the system-wide effects when making operating and investment decisions. As a result of the unbundling from the transmission infrastructure, however, individual generation firms will make these decisions to maximize their own profit, ignoring their action's external effect on other generation firms and the transmission system. Thus, while these changes are prerequisite to a competitive industry, they also create a market characterized by ubiquitous externalities. A key question is whether the transmission management protocols designed to force generation firms to internalize their external dispatching effects also counter the corresponding investment externalities.

In this paper, we formulate a three-period model for studying how the exercise of local market power by generation firms affects both the generating firms' incentives to invest in new generation capacity and the equilibrium investment between the generation and the transmission sectors. The model structure is a mathematical program subject to an equilibrium problem with equilibrium constraints (MEPEC), in which the network planner solves a mathematical programming problem subject to the equilibrium of generation capacity expansion (where each firm solves a mathematical programming problem with equilibrium constraints (MPEC)).

Using a 30-bus network, we show that a "proactive" network planner (i.e., a network planner who plans transmission investments in anticipation of generation investments so that it is able to induce a more socially-efficient Nash equilibrium of generation capacities) can recoup some of the welfare lost due to the unbundling of the generation and the transmission investment decisions by proactively expanding transmission capacity. Conversely, we show that a "reactive" network planner (i.e., a network planner who plans transmission investments only considering the currently installed generation capacities and, in this way, ignoring the interrelationship between the transmission and the generation investments) foregoes this opportunity.

The concept of a proactive network planner was formerly

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proposed by Craft in her doctoral thesis [5]. However, Craft only studied the optimal network expansion in a 3-node network that presented very particular characteristics. Specifically, Craft's work assumes that only one line is congested (and only in one direction), only one node has demand, there is only one generator at each node, energy market is perfectly competitive, and transmission investments are not lumpy. These strong, and quite unrealistic, assumptions make Craft's results hard to apply in a real transmission system. The model presented in this paper extends Craft's model in several ways.

While some other authors have considered the effect of the exercise of local market power on network planning, none of them have modeled the interrelationship between the transmission and the generation investment decisions. In [4], [6], [7], and [9], the authors study how the exercise of market power can alter the transmission investment incentives in a two- and/or three-node network in which the entire system demand is concentrated in only one node. The main idea behind these papers is that if an expensive generator with local market power is requested to produce power as result of network congestion, then the generation firm owing this generator could have no incentive to relieve congestion. Reference [2] presents an analysis of the relationship between transmission capacity and generation competition in the context of a two-node network in which there is local demand at each node. In this paper, the authors argue that relatively small transmission investment may yield large payoffs in terms of increased competition. Bushnell and Stoft [3] propose that transmission investors are granted financial rights (which are tradable among market participants) as reward for the transmission capacity added to the network and suggest a transmission rights allocation rule based on the concept of feasible dispatch. They prove that, under certain circumstances, such a rule can eliminate the incentives for a detrimental grid expansion. However, these conditions are very stringent. Joskow and Tirole [6] analyze the Bushnell-and-Stoft's model when assumptions that better reflect the physical and economic attributes of real transmission networks are introduced. They show that a variety of potentially significant performance problems then arise. Some other authors have proposed more radical changes to the transmission power system. Oren and Alvarado (see [1] and [8]), for example, propose a transmission model in which a for-profit independent transmission company (ITC) owns and operates most of its transmission resources and is responsible for operations, maintenance, and investment of the whole transmission system. Under this model, the ITC has the appropriate incentives to invest in transmission. However, this approach requires the divestiture of all transmission assets, which does not seem to be viable in the US system.

II. The Proactive Transmission Investment Model

We propose a three-period model for studying how generation firms' local market power affects both the firms' incentives to invest in new generation capacity and the equilibrium investment between the generation and the transmission sectors.

A. Assumptions

The model does not assume any particular network structure, so that it can be applied to any network topology. Moreover, the model allows demand at every node of the network. For simplicity, we assume that all nodes are both demand nodes and generation nodes and that there is exactly one firm owning generation facilities at each node. We allow generation firms to exercise local market power. Furthermore, the model allows many lines to be simultaneously congested. Although this fact makes the analysis complex, this is a very important feature of real network operations.

The model consists of three periods, as displayed in Fig. 1. We assume that, at each period, all previous-periods actions are observable to the players making a decision. That is, we define the proactive transmission investment model as a "complete- and perfect-information" game[2] and the equilibrium as "sub game perfect".

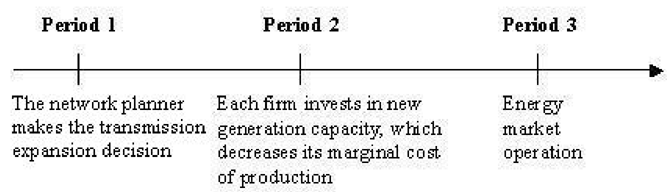

Fig. 1. Three-period model for proactive transmission investment.

The last period (period 3) represents the energy market operation. That is, in this period, we compute the equilibrium quantities and prices of electricity over given generation and transmission capacities. We model the energy market equilibrium in the topology of the transmission network through the DC approximation of Kirchhoff's laws. Specifically, flows on lines can be calculated by using the power transfer distribution factor (PTDF) matrix, whose elements give the proportion of flow on a particular line resulting from an injection of one unit of power at a particular node and a corresponding withdrawal at an arbitrary (but fixed) slack bus. Different PTDF matrices with corresponding probabilities characterize uncertainty regarding the realized network topology in the energy market equilibrium (the generation and transmission capacities are subject to random fluctuations (contingencies) that are realized in period 3 prior to the production and redispatch decisions by the generators and the system operator). We will assume that the probabilities of all credible contingencies are public knowledge.

The energy market equilibrium is considered a subgame with two stages. In the first stage, Nature picks the state of the world (and, thus, settles the actual generation and

[2] A "complete- and perfect-information" game is defined as a game in which players move sequentially and, at each point in the game, all previous actions are observable to the player making a decision.

transmission capacities as well as the shape of the demand and cost functions at each node). In the second stage, firms compete in a Nash-Cournot fashion by selecting their production quantities, while taking into consideration the simultaneous import/export decisions of the system operator whose objective is to maximize social welfare while satisfying the transmission constraints.

In the second period, each generator invests in new generation capacity, which lowers its marginal cost of production at any output level. For the sake of tractability we assume that generators' production decisions are not constrained by physical capacity limits. Instead we allow generators' marginal cost curves to rise smoothly so that production quantities at any node will be limited only by economic considerations and transmission constraints. In this framework generation expansion is modeled as "stretching" the supply function so as to lower the marginal cost at any output level and thus increase the amount of economic production at any given price. Such expansion can be interpreted as an increase in generation capacity in a way that preserves the proportional heat curve or alternatively assuming that any new generation capacity installed will replace old, inefficient plants and, thereby, increase the overall efficiency of the portfolio of plants in producing a given amount of electricity. This continuous representation of the supply function and generation expansion serves as a proxy to actual supply functions that end with a vertical segment at the physical capacity limit. Since typically generators are operated so as not to hit their capacity limits (due to high heat rates and expansive wear on the generators) our proxy should be expected to produce realistic results. The return from the generation capacity investments made in period 2 occurs in period 3, when such investments enable the firms to produce electricity at lower cost and sell more of it at a profit.

In the first period, the system operator makes a single transmission expansion decision in anticipation of the generation expansion decisions (period 2) and the electricity market equilibrium (period 3). In this period, the proactive system operator is limited to decide on the best location and the magnitude for the next transmission upgrade. We assume the transmission expansion does not alter the original PTDF matrices, but only the thermal capacity of the line. This would be the case if, for the expanded line, we replaced all the wires by new ones (with new materials) while using the same existing high-voltage towers. Since the energy market equilibrium will be a function of the thermal capacities of all constrained lines, the Nash equilibrium of generation capacities will also be a function of these capacity limits. The proactive system operator, then, has multiple ways of influencing this Nash equilibrium. By acting as a Stackelberg leader and anticipating the equilibrium of generation capacities, this system operator is able to influence generation firms to make more socially optimal investments.

We further assume that the generation cost functions are both increasing and convex in the amount of output produced and decreasing and convex in generation capacity. Furthermore, as we mentioned before, we assume that the marginal cost of production at any output level is decreasing as generation capacity increases. Moreover, we assume that both the generation capacity investment cost and the transmission capacity investment cost are linear in the extra-capacity added. We also assume downward-sloping linear demand functions at each node. To further simplify things, we assume no wheeling fees.

B. Notation

Sets:

- N: set of all nodes
- L: set of all existing transmission lines
- C: set of all states of contingencies

Decision variables:

- q_i^c: quantity generated at node i in state c
- r_i^c: adjustment quantity into/from node i by the system operator in state c
- g_i: expected generation capacity of facility at node i after period 2
- f_ℓ: expected thermal capacity limit of line ℓ after period 1

Parameters:

- g_i^0: expected generation capacity of facility at node i before period 2
- f_ℓ^0: expected thermal capacity limit of line ℓ before period 1
- g_i^c: generation capacity of facility at node i in state c, given g_i.
- f_ℓ^c: thermal capacity limit of line ℓ in state c, given f_ℓ.
- $P_i^c(\cdot)$: inverse demand function at node i in state c
- $CP_i^c\ (q_i^c,\ g_i^c)$: production cost function of generation firm located at node i in state c
- $CIG_i\ (g_i, g_i^0)$: cost of investment in generation capacity at node i to bring expected generation capacity to g_i.
- $CI_\ell\ (f_\ell,\ f_\ell^0)$: cost of investment in line ℓ to bring expected transmission capacity to f_ℓ.
- $\phi_{\ell,i}^{\ c}$: power transfer distribution factor on line ℓ with respect to a unit injection/withdrawal at node i, in state c

C. The Formulation

First, we formulate the third-period problem. In the first stage of period 3, Nature determines the state of the world. In the second stage, for a given state c, the firm located at node i solves the following profit-maximization problem:

$$\begin{aligned} &Max_{q_i^c} \quad \pi_i^c = P_i^c(q_i^c + r_i^c) \cdot q_i^c - CP_i^c(q_i^c, g_i^c) \\ &s.t. \quad q_i^c \geq 0 \qquad , \quad i \in N \end{aligned} \tag{1}$$

Simultaneously with the generators' production quantity decisions, the system operator solves the following welfare maximizing redispatch problem (for the given state c):

$$\underset{\{r_i^c\}}{Max}\ \Delta W^c = \sum_{i \in N} \left(\int_0^{r_i^c} P_i^c(q_i^c + x_i)\, dx_i \right)$$

$$\begin{aligned} s.t.\quad & \sum_{i\in N} r_i^c = 0 \\ & -f_\ell^{\ c} \le \sum_{i\in N} \phi_{\ell,i}^{\ c} \cdot r_i^c \le f_\ell^{\ c} \qquad , \ \forall\, \ell \in L \\ & q_i^{\ c} + r_i^{\ c} \ \ge\ 0 \qquad\qquad , \ \forall\, i \in N \end{aligned} \tag{2}$$

Given that we assume no wheeling fees, the system operator can gain social surplus, at no extra cost, by exporting some units of electricity from a cheap-generation node while importing them to other nodes until the prices at the nodes are equal, or until some transmission constraints are binding.

The previously specified model assumptions guarantee that both (1) and (2) are concave programming problems, which implies that first order necessary conditions (i.e. KKT conditions) are also sufficient. Consequently, to solve the period-3 problem (energy market equilibrium), we can just jointly solve the KKT conditions of the problems defined in (1), for all $i \in N$, and (2).

In period 2, each risk-neutral firm determines how much to invest in new generation capacity by maximizing the expected value of the investment subject to the anticipated actions in period 3. Since the investments in new generation capacity reduce the expected marginal cost of production, the return from the investments made in period 2 occurs in period 3. Thus, in period 2, the firm located at node i solves the following optimization problem:

$$\begin{aligned} & Max_{g_i}\ \ \mathrm{E}_c\left[\pi_i^c\right] - CIG_i(g_i, g_i^0) \\ & s.t. \qquad \text{KKT conditions for period 3} \end{aligned} \tag{3}$$

The problem defined in (3) is a Mathematical Program with Equilibrium Constraints (MPEC) problem (see [10]). Thus, the period-2 problem can be converted to an Equilibrium Problem with Equilibrium Constraints (EPEC), in which each firm faces (given other firms' commitments and the system operator's import/export decisions) an MPEC problem. However, this EPEC is constrained in a non-convex region and, therefore, we cannot simply write down the first order necessary conditions for each firm and aggregate them into a large problem to be solved directly. In Section IV, we solve this problem for the particular case-study network, using sequential quadratic programming algorithms.

In the first period, the system operator makes a single transmission expansion decision. In this period, the system operator is limited to decide which line (among the already existing lines) it should upgrade, and what transmission capacity it should consider for that line, in order to maximizes the expected social welfare subject to the equilibrium constraints representing the anticipated actions in periods 2 and 3.[3] Thus, in period 1, the system operator solves the following social-welfare-maximizing problem:

$$\begin{aligned} & Max_{\ \ell, f_\ell}\ \sum_{i \in N} \left\{ E_c \left[\int_0^{q_i^c + r_i^c} P_i^c(q)\, dq - CP_i^c(q_i^c, g_i^c) \right] \right\} \\ & \qquad - \sum_{i \in N} \left\{ CIG_i(g_i, g_i^0) \right\} - CI_\ell(f_\ell, f_\ell^0) \\ & \text{s.t.} \qquad \text{KKT conditions of period - 3 problem} \\ & \qquad\quad\ \text{and all optimality conditions of period - 2 problem} \end{aligned} \tag{4}$$

III. Illustrative Example

We illustrate the computational model described above using a stylized version of the 30-bus Cornell network, in which the nodes are located within three zones as displayed in Fig.2. There are six generation firms in the market (each one owning the generator at a single node). Nodes 1, 2, 13, 22, 23, and 27 are the generation nodes. There are 39 transmission lines.[4]

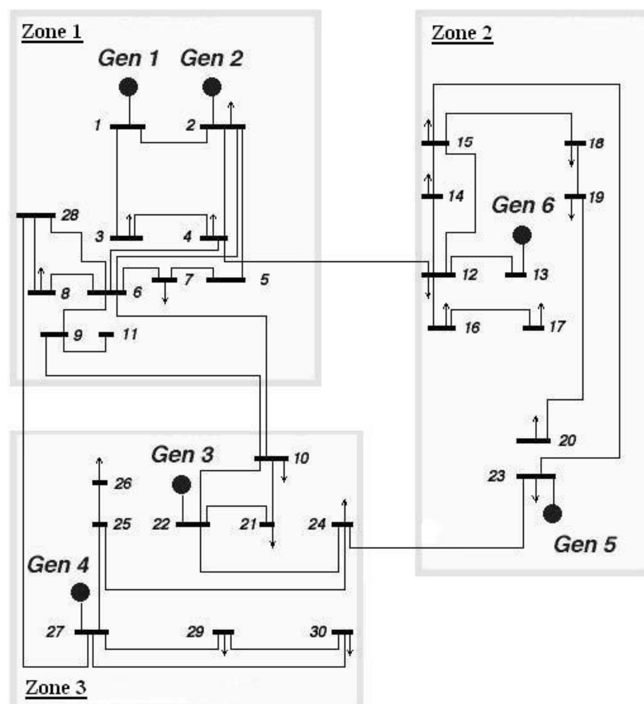

Fig. 2. 30-bus Cornell network.

The uncertainty associated with the energy market operation is classified into seven independent contingent states (see table I). Six of them have small independent probabilities of occurrence (two involve demand uncertainty, two involve network uncertainty and the other two involve generation uncertainty). Table II shows the nodal information in the normal state.

[3] No attempt is made to co-optimize the system operators' transmission expansion and redispatch decisions.

[4] The electric characteristics of the lines are omitted due to space constraints and can be obtained upon request from the authors.

TABLE I
STATES OF CONTINGENCIES ASSOCIATED TO THE ENERGY MARKET OPERATION

State	Probability	Type of uncertainty and description
1	0.82	Normal state: Data set as in table II
2	0.03	Demand uncertainty: All demands increase by 10%
3	0.03	Demand uncertainty: All demands decrease by 10%
4	0.03	Network uncertainty: Line 15-23 goes down
5	0.03	Network uncertainty: Line 23-24 goes down
6	0.03	Generation uncertainty: Generator at node 1 goes down
7	0.03	Generation uncertainty: Generator at node 13 goes down

TABLE II
NODAL INFORMATION USED IN THE 30-BUS CORNELL NETWORK IN THE NORMAL STATE OF CONTINGENCY

Data type (units)	Information	Nodes where apply
Inverse demand function (\$/MWh)	$P_i(q) = 50 - q$	1, 2, 5, 6, 9, 11, 13, 16, 18, 20, 21, 22, 25, 26, 27, 28, and 29.
Inverse demand function (\$/MWh)	$P_i(q) = 55 - q$	4, 8, 10, 12, 14, 15, 17, 19, 24, and 30.
Inverse demand function (\$/MWh)	$P_i(q) = 60 - q$	3, 7, and 23.
Generation cost function (\$/MWh)	$CP_i(q_i, g_i) = (0.25 \cdot q_i^2 + 20 \cdot q_i) \cdot (g_i^0 / g_i)$	1, 2, 13, 22, 23, and 27 (all generation nodes).

As shown in table II, we assume the same production cost function, $CP_i^c(\cdot)$, for all generators. Note that $CP_i^c(\cdot)$ is increasing in q_i^c, but it is decreasing in g_i^c. Moreover, recall that we have assumed generators have unbounded capacity. Thus, the only important effect of investing in generation capacity is lowering the production cost. We also assume that all generation firms have the same investment cost function, given by $CIG_i\ (g_i,g_i^0) = 8\cdot(g_i - g_i^0)$, in dollars. The before-period-2 expected generation capacity at node i, g_i^0, is 60 MW (the same for all generation nodes).

The KKT conditions for the period-3 problem of the proactive system operator (PSO) model constitute a Linear Complementarity Problem (LCP). We solve it, for each contingent state by minimizing the complementarity conditions subject to the linear equality constraints and the non-negativity constraints.[5] The period-2 problem of the PSO model is an Equilibrium Problem with Equilibrium Constraints (EPEC), in which each firm faces a Mathematical Program subject to Equilibrium Constraints (MPEC).[6] We attempt to solve for an equilibrium, if at least one exists, by iterative deletion of dominated strategies. We solve each firm's profit-maximization problem using sequential quadratic programming algorithms implemented in MATLAB®.

For the PSO model, the optimal levels of generation capacity under absence of transmission investments are (g_1^*, g_2^*, g_3^*, g_4^*, g_5^*, g_6^*) = (100.92, 103.72, 101.15, 95.94, 77.07, 87.69), in MW. Table III lists the corresponding generation quantities (q_i), adjustment quantities (r_i) and nodal prices (P_i) in the normal state. Fig. 3 illustrates these results for the Cornell network. In Fig. 3, thick lines represent the transmission lines reaching their thermal capacities (in the indicated direction) and circles correspond to those nodes with the highest prices (above \$48/MWh).

TABLE III
GENERATION QUANTITIES, ADJUSTMENT QUANTITIES, AND NODAL PRICES IN NORMAL STATE, IN THE PSO MODEL, UNDER ABSENCE OF TRANSMISSION INVESTMENTS

Node	q_i (MWh)	r_i (MWh)	P_i (\$/MWh)
1	27.397	-24.827	47.43
2	27.808	-25.230	47.42
3	0	12.544	47.46
4	0	7.539	47.46
5	0	2.600	47.40
6	0	2.624	47.38
7	0	12.614	47.39
8	0	7.630	47.37
9	0	2.838	47.16
10	0	7.950	47.05
11	0	2.838	47.16
12	0	6.932	48.07
13	24.706	-21.547	46.84
14	0	6.799	48.20
15	0	6.612	48.39
16	0	1.932	48.07
17	0	6.932	48.07
18	0	1.022	48.98
19	0	6.022	48.98
20	0	1.022	48.98
21	0	3.033	46.97
22	27.055	-23.997	46.94
23	21.724	-7.474	45.75
24	0	8.474	46.53
25	0	3.152	46.85
26	0	3.152	46.85
27	26.310	-23.354	47.04
28	0	2.663	47.34
29	0	2.500	47.50
30	0	7.007	48.00

[5] Recall that any LCP can be written as the problem of finding a vector $x \in \Re^n$ such that $x = q + M\cdot y$, $x^T\cdot y = 0$, $x \geq 0$, and $y \geq 0$, where $M \in \Re^{n \times n}$, $q \in \Re^n$, and $y \in \Re^n$. Thus, we can solve it by minimizing $x^T\cdot y$ subject to $x = q + M\cdot y$, $x \geq 0$, and $y \geq 0$. If the previous problem has an optimal solution where the objective function is zero, then that solution also solves the corresponding LCP.

[6] See [10] for a definition of both EPEC and MPEC.

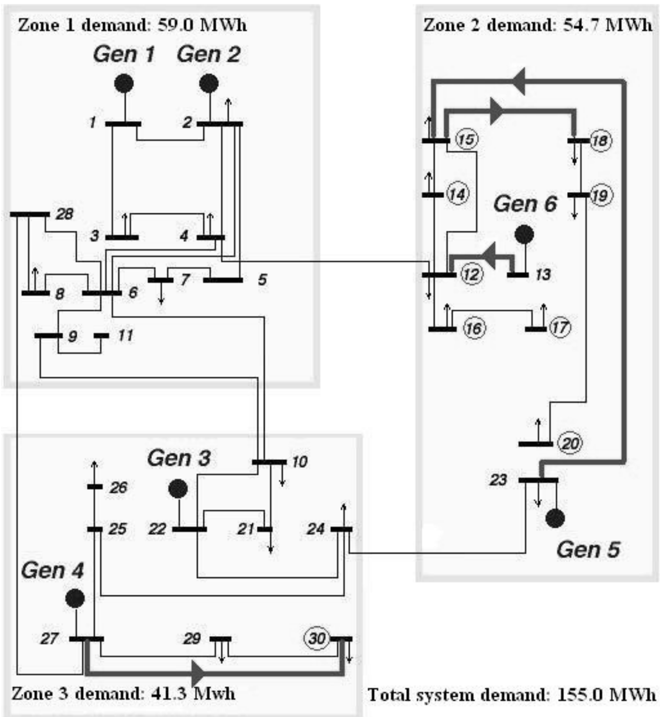

Fig. 3. Results of the PSO model in the normal state, under absence of transmission investment, for the 30-bus Cornell network.

To solve the period-1 problem of the PSO model, we iteratively solve period-2 problems in which a single line has been expanded and, then, choose the expansion producing the highest expected social welfare. For simplicity, we do not consider transmission investment costs (it can be thought that the per-unit transmission investment cost is the same for each line upgrade so that we can get rid of these costs in the expansion decision). In this sense, our results establish an upper limit in the amount of the line investment cost. The four congested lines in the normal state, under absence of transmission investment, are the obvious candidates for the single line expansion. We tested the PSO decision by comparing the results of independently adding 100 MVA of capacity to each one of these four lines. The results are summarized in table IV.

TABLE IV
ASSESSMENT OF SINGLE TRANSMISSION EXPANSIONS UNDER THE PSO MODEL

Expansion Type	Avg. L	P.S. ($/h)	C.S. ($/h)	C.R. ($/h)	W ($/h)	g^* (MW)
No expansion	0.552	2975.2	574.7	68.4	3618.3	[100.92; 103.72; 101.15; 95.94; 77.07; 87.69]
100 MVA on line 12-13	0.561	3015.7	591.3	39.9	3646.9	[100.62; 103.40; 100.93; 98.50; 78.56; 97.99]
100 MVA on line 15-18	0.556	2957.0	576.5	82.6	3616.1	[101.35; 104.09; 101.01; 94.38; 79.28; 92.71]]
100 MVA on line 15-23	**0.571**	**3049.9**	**602.2**	**26.4**	**3678.5**	**[100.01; 102.80; 102.90; 102.37; 101.45; 85.06]**
100 MVA on line 27-30	0.555	2986.1	581.1	58.2	3625.4	[101.10; 103.89; 101.40; 101.46; 77.68; 86.30]

In table IV, "Avg. L" corresponds to the average expected Lerner index[7] among all generation firms, "P.S." is the expected producer surplus of the system, "C.S." is the expected consumer surplus of the system, "C.R." represents the expected congestion rents over the entire system, "W" is the expected social welfare of the system, and "g^*" corresponds to the vector of all Nash-equilibrium expected generation capacities.

From table IV, it is evident that the best single transmission line expansion (in terms of expected social welfare) that a proactive system operator can choose in this case is the expansion of line 15-23. Moreover, it is interesting to observe that some expansion projects (as adding 100 MVA on line 15-18) can decrease social welfare.

Now, we are interested in comparing the PSO decision with the decision that would take a reactive system operator (RSO) under the same system conditions. In the RSO model, the system operator plans the social-welfare-maximizing location and magnitude for the next transmission upgrade while considering the currently installed generation capacities. That is, the RSO does not take into consideration the potential effect that its decisions could have over the equilibrium of generation capacities. In evaluating the outcome of RSO investment policy we are considering the generators' response to that investment and its implication on the spot market equilibrium.

We tested the RSO decision by comparing the results of independently adding 100 MVA of capacity to each one of the same four lines as before. The results are summarized in table V, where we use the notation $\overline{x}$ to represent the value of x as seen by the RSO.

TABLE V
ASSESSMENT OF SINGLE TRANSMISSION EXPANSIONS UNDER THE RSO MODEL

Expansion Type	$\overline{\text{Avg.L}}$	$\overline{\text{P.S.}}$ ($/h)	$\overline{\text{C.S.}}$ ($/h)	$\overline{\text{C.R.}}$ ($/h)	$\overline{\text{W}}$ ($/h)
No expansion	0.395	2732.4	387.9	9.1	3129.4
100 MVA on line 12-13	**0.395**	**2732.4**	**388.3**	**8.9**	**3129.6**
100 MVA on line 15-18	0.395	2732.1	388.3	8.9	3129.3
100 MVA on line 15-23	0.395	2732.5	388.2	8.8	3129.5
100 MVA on line 27-30	0.395	2732.4	387.9	9.1	3129.4

From table V, it is clear that the social-welfare-maximizing transmission expansion for the RSO is, in this case, to expand line 12-13. Thus, the true optimal levels of the RSO model solution are: Avg. L = 0.561, P.S. = \$ 3,015.7 /h, C.S. = \$591.3 /h, C.R. = \$ 39.9 /h, W = \$ 3,646.9 /h, and g^* = (100.62, 103.40, 100.93, 98.50, 78.56, 97.99), in MW. By comparing table IV and table V, it is evident that the optimal decision of the PSO differs from the optimal decision of its reactive counterpart.

Finally, it is interesting to compare the results obtained with the PSO model and those obtained with an hypothetical integrated-resources planner (IRP). In the IRP model, we assume that the IRP jointly plans generation and transmission expansions, although the energy market operation is still decentralized. We tested the IRP decision by comparing the results of independently adding 100 MVA of capacity to each

[7] The Lerner Index is defined as the fractional price markup i.e. (Price – Marginal cost) /Price

one of the same four lines as before. The results are summarized in table VI.

TABLE VI
ASSESSMENT OF SINGLE TRANSMISSION EXPANSIONS UNDER THE IRP MODEL

Expansion Type	Avg. L	P.S. ($/h)	C.S. ($/h)	C.R. ($/h)	W ($/h)	g^* (MW)
No expansion	0.549	2979.5	571.1	68.5	3619.0	[100.56; 100.06; 99.67; 96.24; 77.12; 87.61]
100 MVA on line 12-13	0.564	3009.7	596.4	44.3	3650.4	[101.17; 103.90; 97.61; 97.68; 85.15; 97.87]
100 MVA on line 15-18	0.554	2969.9	578.6	70.9	3619.4	[103.00; 107.98; 95.63; 93.94; 83.92; 85.28]
100 MVA on line 15-23	**0.568**	**3053.1**	**597.0**	**30.1**	**3680.2**	**[98.12; 100.87; 101.22; 101.07; 99.93; 87.20]**
100 MVA on line 27-30	0.555	2989.4	582.2	55.9	3627.5	[102.02; 102.66; 100.64; 100.67; 80.48; 84.04]

From table VI, it is clear that the social-welfare-maximizing transmission expansion for the IRP is, in this case, to expand line 15-23 (the same as in the PSO model). By comparing table IV and table VI, we can observe that, although the IRP makes the same decision as the PSO, this IRP is able to increase the expected social welfare by choosing generation capacities that are more socially efficient than those chosen by the generation firms in the PSO model.

IV. CONCLUSIONS AND FUTURE WORK

We proposed a three-period model for studying how the exercise of local market power by generation firms affects the equilibrium investment between the generation and the transmission sectors. We showed that, although a PSO cannot do better (in terms of expected social welfare) than an IRP, it can recoup some of the lost welfare by proactively expanding transmission capacity. Moreover, we illustrated that the optimal transmission expansion made by a PSO can differ from the one made by a RSO. In that case, the PSO will make more socially efficient expansion decisions than its reactive counterpart because a PSO takes into consideration not only the welfare gained directly by adding transmission capacity (on which a RSO bases its decision), but also the way in which its investment alters the Nash equilibria of expected generation capacities.

There are several ways in which the model proposed here can be extended. One interesting extension is the analysis of two sequential transmission investment decisions. That is, once we applied our model and decided the best transmission expansion, to determine the next best single transmission upgrade. We expect that the sequential investment decisions by the PSO diverge from those made by a RSO. Another attractive extension is the analysis of our model when building lines at new locations (rather than upgrading existing lines) is allowed. In this case, an expansion can change the electric properties of the network (and, thus, the used PTDF matrices), which represents a more realistic scenario. Other valuable extension is the study of the model when allowing firms to own generators located at more than a single node. We expect that such a possibility enhances generation firms' market power and, in this way, varies the equilibrium investment between the generation and the transmission sectors. This fact will potentially create additional social benefits achieved by a system operator that acts proactively.

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VI. ACKNOWLEDGMENT

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VII. BIOGRAPHIES

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