Promoting the Investment on IPPs for Optimal Grid Planning

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***Abstract*—This paper presents a transmission expansion planning (TEP) model which coordinates investment decisions in monopolistic transmission and decentralized generator sectors. The proposed planning approach gauges transmission congestion and security constraints with respect to transmission investments while promoting investments on independent power produces (IPPs) through incentive payments. The paper includes discussions on incentive mechanisms and prioritization among qualified IPPs for several planning scenarios. Such incentives might be necessary to trigger investments on IPPs earlier than those projected by the decentralized generation system, when the power system security is threatened. The proposed planning approach would optimize the sum of transmission investments, incentive payments to IPPs, and congestion costs along the planning horizon. The case studies illustrate how the proposed planning algorithm could be utilized in order to determine incentive payments to candidate generators when necessary, and prioritize such incentives among multiple IPP candidates.**

***Index Terms*—Incentive payments, IPP investments, transmission congestion, transmission expansion planning, transmission security.**

NOMENCLATURE

b	Index for subperiod.
d	Discount rate.
i	Index for generator (existing and candidate).
k	Index for line (from bus m to bus n).
q	Single contingency index.
t	Year index.
CL	Number of candidate transmission lines.
NCG	Number of candidate generators.
NS	Number of subperiods.
NT	Number of planning year.
CI_{kt}	Capital investment cost of transmission line k in year t ($/yr).
$R_{C,ibt}$	Forecasted energy sales price of candidate IPP i at subperiod b in year t ($/MWh).
α_i	Profit coefficient of IPP $i(\%)$.
CI_{it}	Capital investment cost of IPP i in year t ($/yr).
$P_{GC,ibt}$	Dispatched capacity of candidate generator i at subperiod b in year t (MW).
IP_{it}	Incentive payment required by IPP i in year t ($/yr).
$\mathrm{OC}_{GC,ibt}$	Operating costs of candidate IPP i at subperiod b in year t ($/MWh).
AOCC_{bt}	Additional operation cost due to congestion at subperiod b in year t ($/yr).
X_{it}	Installation status of candidate generator of IPP i in year t, 1 if installed, otherwise 0.
X_{kt}	Investment status of candidate line k in year t.
DT_{bt}	Duration of subperiod b in year t (h).

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I. INTRODUCTION

THE liberalization and restructuring processes worldwide have introduced new complexities to the transmission expansion problem (TEP) [1]–[5]. This movement has introduced competition at the two extreme points of the industry infrastructure (i.e., generation and retailing) while keeping transmission and distribution sectors as natural monopolies. TEP is presented as a process which is decoupled from generation and distribution planning despite their natural and indispensable dependencies. This means that, in some ways, the transmission network will have to solicit users' involvement both at the generation and the demand sides which would introduce a new level of the TEP uncertainty.

This paper presents a new model for the coordination of TEP and decentralized generation investment planning. The model gauges the level of transmission congestion and security with respect to transmission investments while promoting generation investments through incentive payments to mitigate the operation risks when necessary. For the purpose of maintaining the system security such incentives which would trigger generation investments could be paid earlier than the IPPs' projected investment date.

The generation capacity market and the institution of capacity signals have been a controversial issue in the electricity industry restructuring. Many experts argue that the capacity mechanism is essential for encouraging the investment in the new capacity [6]. In theory, energy and ancillary services markets should provide incentives for such investments. However, most peaking units may not recover their fixed costs of investment without market price spikes. Thus, significant price volatilities may be necessary to make such investments feasible in the absence of capacity payments [7]. Given the political realities of electricity markets, prices may fluctuate insufficiently to induce investments when the available capacity is tightened; then an explicit capacity mechanism would be needed to signal capacity shortages and induce investments on generation [8].

The coordination between transmission and generation resource planning was addressed previously. Roh *et al.* proposed a model that brings transmission and electricity market into the sphere of long-term generation resource planning [9]. Security payments to generation companies (GENCOs) by the ISO are proposed for supplying the load and satisfying the network security. The study shows that a proper expansion of transmission capacity could lower the ISO's security payment to GENCOs. Our planning approach considers this fact inherently by coordinating transmission and generation planning decisions. Botterud *et al.* presented a stochastic dynamic generator investment model which offers a comprehensive treatment of long-term uncertainties and their influence on optimal generator investment decisions [10]. The proposed model assesses optimal investment strategies when the increase in demand, and thereby future prices, are uncertain. However, it considers only the generator investment decision and ignores its close linkage with transmission expansion. The interaction between transmission and generation in TEP was also investigated recently in [11]. The objective of TEP is to maximize the social welfare based on a valuation methodology outlined as proactive transmission network planning. It is assumed that network planner anticipates the way that generation investment and operations would react.

This study proposes an enhancement to the planning model given in [12] by considering incentive payments to IPPs to trigger generation investments when necessitated by the system security. The proposed coordinated planning model in [12] provides the best combination of transmission and generation investment planning, although there is no guarantee that profit-making IPPs will follow the proposed options which would maximize the social-welfare. Our approach is unique as it proposes an incentive mechanism to IPPs that considers this situation within a coordinated transmission planning problem.

Fig. 1 depicts the flowchart of the proposed method. The main distinction in this study is the integration of the IPP investment planning decisions with TEP when considering the system security in long-term planning studies. Thus generator investments which contribute to the optimal system planning (considering the network security) but might be delayed by IPPs for various reasons are considered in the proposed planning algorithm by including incentive mechanisms. For example, those IPPs which are essential for maintaining the system security during on-peak periods might require additional incentives due to the insufficient dispatch of their units during off-peak periods. We propose such an incentive mechanism within the context of coordinated planning performed by a central entity, which is assumed to be a state-owned transmission company. Accordingly, the planning concern as to whether profit-making IPPs will follow the coordinated planning option is taken into account in this paper.

The rest of the paper is organized as follows. The proposed planning model and the solution methodology are described in Section II which also presents the IPPs' investment problem

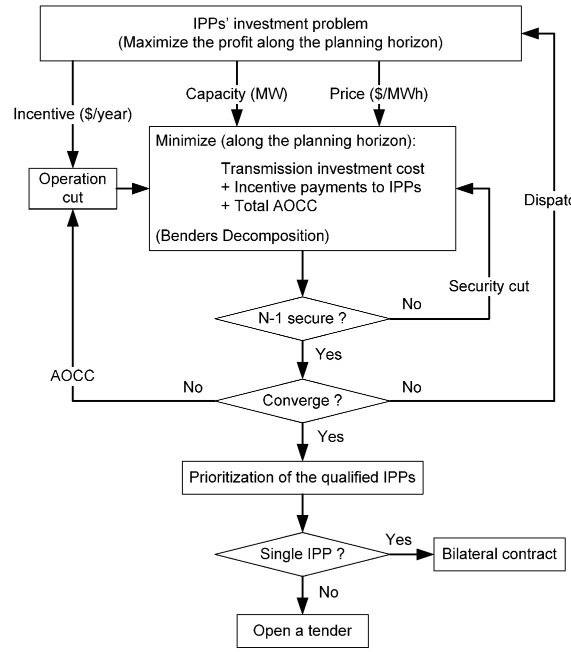

Fig. 1. Integration of IPPs' investment planning decisions with TEP.

and the interaction between the transmission company and IPPs during the planning process. Section III presents the case study of a two-bus system which enables easy understanding of the contribution of this paper, and application of the approach to modified IEEE 30-bus system. Prioritization among multiple IPPs that qualified for incentive payment and determination of the incentive mechanism are also discussed in Section III. The conclusion drawn from the study is provided in Section IV.

II. Planning Model and Incentive Mechanism

A. Centralized Transmission Expansion Planning Problem

The objective of the proposed planning problem is to optimize the transmission investment cost, the incentive payments to IPPs which contribute to the optimal solution, and the total additional operation cost due to congestion (AOCC), in the planning horizon while satisfying the system security based on the single contingency (i.e., N-1) criterion. The objective function is formulated as

$$\mathrm{Min}\left\{\sum_{t=1}^{\mathrm{NT}}\sum_{k=1}^{\mathrm{CL}}\left[\frac{\mathrm{CI}_{kt}*X_{kt}}{(1+d)^{(t-1)}}\right] + \sum_{t=1}^{\mathrm{NT}}\sum_{i=1}^{\mathrm{NCG}}\frac{\mathrm{IP}_{it}*X_{it}}{(1+d)^{(t-1)}} + \sum_{t=1}^{\mathrm{NT}}\sum_{b=1}^{\mathrm{NS}}\frac{\mathrm{AOCC}_{bt}}{(1+d)^{(t-1)}}\right\} \quad (1)$$

where AOCC is the difference between generation dispatch costs when ignoring and considering transmission constraints along the planning horizon. The objective function is decomposed into security and operation problems and the DC power flow model [13] is utilized in the formulation of Benders cuts as illustrated in Fig. 1. Security cuts ensure the load curtailment criteria while meeting the N-1 contingency along the planning horizon. On the other hand, operation cuts force the planning algorithm to search for a better solution that would result in more economic dispatch solutions (i.e., minimize the AOCC). Thereby, transmission investment cost, congestion cost and incentive payments to the qualified IPPs are optimized iteratively. Here, the generator investment costs in the planning algorithm proposed in [12] are replaced by incentive payments to IPPs.

B. Decentralized Generator Investment Planning Problem

The main objective of a generation planning problem executed by IPPs (i.e., non-utility generators) is to maximize the profit based on investments. A generation investment project is profitable if the discounted project return is positive. The internal rate of return (IRR) is a popular concept for measuring the discounted project returns [14].

It is assumed here that there are no coupling constraints among IPPs for investment decisions. Accordingly, the investment planning problem of IPP for each generation candidate is to maximize the profit based on the corresponding investment along the planning horizon:

$$\begin{aligned} \mathrm{Max} \Biggl\{ & \sum_{t=1}^{\mathrm{NT}} \sum_{b=1}^{\mathrm{NS}} \frac{DT_{bt}}{(1+d)^{(t-1)}} \\ & * \begin{pmatrix} R_{C,ibt} * P_{\mathrm{GC},ibt} \\ -\mathrm{OC}_{\mathrm{GC},it} * P_{\mathrm{GC},ibt} \end{pmatrix} \\ & - \sum_{t=1}^{\mathrm{NT}} \frac{\mathrm{CI}_{it} * X_{it}}{(1+d)^{(t-1)}} \Biggr\} \end{aligned} \tag{2}$$

where

$$R_{C,ibt} = \alpha_i * \mathrm{OC}_{\mathrm{GC},ibt}. \tag{3}$$

C. Incentive Requirement of IPPs

An investment decision for a specific IPP depends on its forecasted profit, which is a function of expected energy production (2). For a fixed energy sale price, R_C, the expected profit depends solely on the energy production. If an IPP could forecast the level of energy sales (i.e., dispatch level) for a predefined level of energy sale price, then its investment decision would be as simple as calculating the IRR based on procurements. Therefore, the expected dispatch level is a critical component of a candidate's investment decision which gives an important signal to the IPPs on their forecasted energy price. The IPP would presumably make no investments unless its deficiency is compensated. Essentially, the correct time for making any investment is when the discounted project return is positive. Accordingly, the minimum incentive payment required by candidate i in year t is assumed to be the difference between the annual investment and the expected profit form energy sales stated as

$$\begin{aligned} \mathrm{IP}_{it} = & \frac{\mathrm{CI}_{it} * X_{it}}{(1+d)^{(t-1)}} \\ & - \sum_{b=1}^{\mathrm{NS}} \frac{\mathrm{DT}_{bt}}{(1+d)^{(t-1)}} * \begin{pmatrix} R_{C,ibt} * P_{\mathrm{GC},ibt} \\ -\mathrm{OC}_{\mathrm{GC},it} * P_{\mathrm{GC},ibt} \end{pmatrix}. \end{aligned} \tag{4}$$

When (4) is negative, the investments are profitable, the required incentive is assumed to be zero, and the IPP's investment could manipulate the mechanism.

The proposed incentive mechanism may encourage IPPs to game the market by manipulating the incentives and requiring additional payments. However, the additional incentives will be rejected by the proposed algorithm if an alternative option is available. Such alternatives may include either transmission enforcements or the selection of another IPP with more reasonable incentive requirements. The selection of more economical alternatives among candidates is made possible by Benders cuts. On the other hand, when alternative candidates are not available (due to locational importance), an IPP whose commitment is critical to the system security may essentially abuse the situation. That is, security cuts generated during the iterative planning process may force such investments regardless of their costs (i.e., incentive requirements). The proposed planning model can be utilized by the authorities to identify such opportunities by applying sensitivity analyses and investigating the impact of energy prices on planning alternatives.

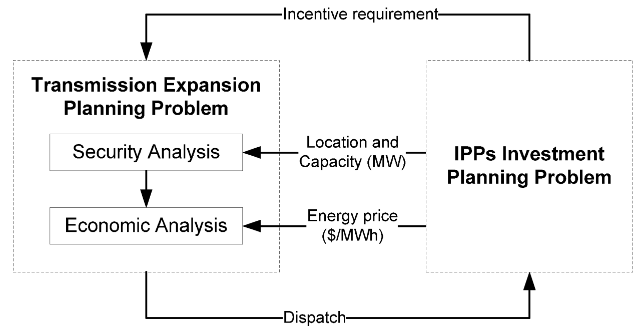

Fig. 2. Information exchange between the transmission company and IPPs.

D. Interaction Between Transmission Company and IPPs

In the proposed approach, each IPP provides the energy sale price of the corresponding generation investment to the ISO. The ISO calculates the expected economic dispatch along the planning horizon. Accordingly, each IPP determines its annual incentive requirements for investments. These incentive requirements are utilized as payments in determining the operation cuts which are iteratively included as constraints of the objective problem (1). The interaction between the transmission company and IPPs which is managed by the ISO is illustrated in Fig. 2. Fig. 1 shows a more detailed information exchange which continues until an optimal planning solution is found.

III. CASE STUDIES

The case studies include a two-bus system and the IEEE 30-bus system as discussed below.

A. Two-Bus System

The two-bus system depicted in Fig. 3 shows two generators that can supply the loads at two different buses. It is assumed that G1, which is located at a distance from the large load at Bus 2, is cheaper than G2 (i.e., closer unit). The solid lines correspond to existing transmission lines and the dashed lines correspond to the transmission reinforcement. The dashed generator at Bus 2 corresponds to a candidate investment by an IPP. The annual load growth rate is 5% at Bus 1 and 8% at Bus 2. The transmission investment cost is 800 $/MW-mile. A 5% annual interest rate based on a ten-year loan is utilized to calculate the annual capital investment for transmission line and generator.

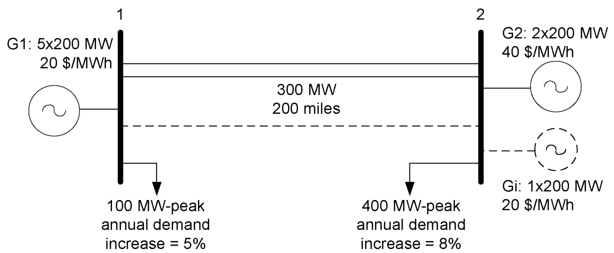

Fig. 3. Two-bus system.

TABLE I
TWO-BUS SYSTEM CANDIDATE GENERATOR DATA (G_I)

Capacity (MW)	Capital investment cost ($M/MW)	Forecasted energy sale price ($/MWh)	Profit in energy sales (%)
200	0.75	20	60

TABLE II
TWO-BUS SYSTEM—CASE 1 RESULTS

Transmission investment	TTIC * ($M)	AOCC ($M)	TC ** ($M)
Year 7	24.44	6.09	30.53

* TTIC: Total transmission investment cost
** TC: Total cost along the planning horizon

The generation investment data are given in Table I. Provided that the candidate generator is operated at full capacity (i.e., 8760*200 = 1752 GWh per year), the discounted annual profit based on its investment is approximately 2$M/year. The profit will decrease along the planning horizon if the unit is operated at less than the full capacity.

The following cases are studied for the two-bus system:

Case 1—Without Promoting IPP Investment: The TEP problem is solved without considering the candidate generator. According to the given demand forecasts, the total demand to be supplied in two buses will be approximately 1025 MW in year 10. The existing generators could not supply this demand unless the transmission line enforcement would take place. The planning problem in this case will only determine the optimal timing for transmission investment. The TEP results are given in Table II. The transmission enforcement will take place in year 7 despite the congestion in year 6. It is obvious as the $6.09 M AOCC in year 6 is smaller than the annual transmission investment (i.e., $6.11 M). On the other hand, given the high annual peak demand increase, the AOCC would be $14.9 M unless the transmission investment would take place in year 7. The 25 MW of total demand is supplied by the expensive generator G2 in year 10 since G1 is already fully loaded. According to the definition, the total AOCC is zero in year 10.

Case 2—Promoting the IPP Investment: The candidate generator investment at Bus 2 is considered. Table III shows that the transmission line enforcement is deferred by four years provided that the candidate generation investment is procured in year 7. Although the candidate generator is fully loaded in year 10, the transmission investment mitigates the possible congestion by enabling the dispatch of cheaper generator G1. The $6.09 M AOCC is again due to the congestion in year 6 as in Case 1. The annual incentives to trigger generation investments are given in Table IV. Since no generation dispatch is required in years 1–6, the incentive requirement is the same as the annual capital cost of the generator. The incentives provided in years 7 and 8 would compensate the IPP's deficit which is due to low dispatch. Note that even though the energy sale prices of the existing generator G1 and candidate generator Gi are the same, the dispatch priority is given to G1. It is assumed that the existing generator G1 already has long-term contracts and therefore deserves the priority, which is a reasonable assumption.

TABLE III
TWO-BUS SYSTEM—CASE 2 RESULTS

Transmission investment year	Generator investment year	TTIC ($M)	TIP* ($M)	AOCC ($M)	TC ($M)
10	7	6.11	14.44	6.09	26.64

* TIP: Total incentive payment to the IPP

TABLE IV
TWO-BUS SYSTEM—CASE 2 INCENTIVE PAYMENTS

Year	1-6	7	8	9	10
Dispatch (MW)	0	85.53	140.37	199.6	200
Incentive payment ($M)	19.1	10.1	4.34	0	0
Investment status of Gi *	0	1	1	1	1

* If installed: 1, otherwise: 0

TABLE V
TWO-BUS SYSTEM—CONSUMER POINT OF VIEW

Case	TIRC *($M)	TEC ** ($M)	TC ($M)
1	24.44	1426.14	1450.58
2	20.55	1421.51	1442.06

* TIRC: Total investment related cost (TTIC + TIP)
** TEC: Total energy cost

This example shows the effectiveness of promoting the generation investments in the optimal TEP. The incentive payments are required to trigger generation investments earlier than envisaged by IPPs. When there are multiple candidate generators, those which contribute significantly to the system security and optimal operation are given the priority. The security and operational cuts in the proposed planning approach satisfy this criterion when considering the marginal effects of generation investments on the system security and optimal operation.

Table V compares the results of Cases 1 and 2 from the consumers' viewpoint in which Case 2 provides a more economic solution. The difference in the total cost between the two cases is $3.89 M from the transmission company's viewpoint (see Tables II and III) and $8.52 M from the consumers' viewpoint (see Table V).

In Case 1, the dispatch of expensive generator G2 is inevitable in the last year as G1 is fully dispatched and there is no other supplier available. Although the AOCC by definition is zero in year 10, the operation of G2 increases the cost to consumers by $\$8.52\,\mathrm{M} - \$3.89\,\mathrm{M} = \$4.63\,\mathrm{M}$. Consequently, the utilization of AOCC approach provides the optimal planning solution while assessing the annual investment/profit against congestion cost.

One of the transmission planner's main concerns in promoting multiple market players is the inability to institute a fair incentive mechanism in the market. In the example, G2 at

Bus 2 might consider that the incentives will provide unfair advantages to Gi when contributing to the transmission system security. Indeed, both G2 and Gi have the same marginal effects on security, although Gi contributes to the economic dispatch additionally. On the other hand, if G2 benefits from the promotion as well, then the cost of planning may not be optimal.

The Gi in Case 2 deserves an incentive due to its contribution to the system security and optimal operation. Before proposing an incentive plan, it is better to analyze the two-bus example further. Table IV shows that the additional cost of energy due to the incentive payment in year 7 is 13.48 $/MWh (i.e., $\$10.1M/85.53$ MW/8760 h). Accordingly, the breakpoint energy sale price for the IPP's investment on Gi in year 7 is 33.48$/MWh (i.e., 20 + 13.48). In order to be fair, a tender could be opened in the initial year to buy $85.53\ \mathrm{MW} \times 8760\ \mathrm{h} \approx 750$ GWh energy at 33.48 $/MWh in year 7 and $140.37\ \mathrm{MW} \times 8760\ \mathrm{h} \approx 1230$ GWh at 23.53$/MWh in year 8. If the existing generator G2 signs a contract to sell energy at those predefined prices, then there would be no need to promote the investment. It should be noted that this amount of advance energy purchase agreement with G2 will delay the transmission enforcement by two years unless the investment of G2 takes place in year 9. On the other hand, the IPP is expected to make the investment. Otherwise G2 will hold its market power unless the transmission enforcement would take place.

Given the feasibility of investing on Gi in year 7 with additional incentives, the existing generator G2 is clearly competitive as its energy sale price (40$/MWh) is higher than that of Gi even after paying the incentive (i.e., 33.48$/MWh). So our approach not only ensures the system security but also enables the appraisal at expected energy sale prices. Thereby, the regulatory authority would have additional ideas on the competition level and market power.

This simple example illustrates how the candidate investments, which contribute to the planning problem (1) at most, are successfully selected by the proposed planning methodology. In a specific case when several IPPs are willing to invest in a same bus, the operation cut considers the incentive payments to all candidate generators as well as investment cost of transmission lines and AOCC. This is essential as the candidate generators willing to connect to the same bus will have the same incremental contribution to the security (i.e., load curtailment). Note that, the candidate generator Gi in the simple two-bus example deserves an incentive payment despite that G2 is connected to the same bus. The reason is that the contribution of Gi to reducing the AOCC is higher than its incentive requirement along the planning horizon. The next example illustrates the performance of the proposed approach when there is more than one candidate generator considered for investment.

B. IEEE 30-Bus System

The proposed planning approach is applied to the modified IEEE 30-bus system, depicted in Fig. 4, to analyze the performance of the proposed approach when there are several candidate generators. The existing transmission grid satisfies the single contingency security criterion at the initial year. The possible transmission enforcements are shown in Fig. 4. The initial set of candidate transmission lines are determined based on preliminary load flow analyses. The lines which are loaded more than 50% in the initial year are selected as candidates for investment. The initial grid consists of 50 transmission lines, 15 candidate transmission lines, 21 demand buses, seven existing power plants, and eight candidate generators. The length of each transmission line (in miles) is indicated in Fig. 4. Buses with relatively higher load densities are indicated by bold arrows. The modified IEEE 30-bus system data which include transmission lines, generators, and forecasted load are given in http://motor.ece.iit.edu/Data/IEEE_30bus_modified.xls. It is assumed for simplicity that the construction time for each transmission lines or generator is one year.

TABLE VI
IEEE 30-BUS SYSTEM CANDIDATE GENERATOR TYPES

Type [(1)]	Capacity (MW)	Capital investment cost ($M/MW)	Loan schedule	ESP [(2)] ($/MWh)	Profit [(3)] (%)
H	300 or 100 (see the Case studies)	1	20 years 7%	18	70
T		0.6		20	40
C		0.5		22	30

[(1)] H: Hydro plant; T: Coal fired thermal plant; C: Natural gas combined cycle plant. [(2)] ESP: Energy sale price. [(3)] Profit based on energy sale price

The candidate investment pool includes three types of generators as illustrated in Table VI. For simplicity, generator capacities are all assumed to be same. In this table, the capital investment on hydro generators is the highest. The hydro energy sale price is the lowest which provides the highest profit among the candidate generators for the given energy sale price. It is assumed that all candidate generators provide the same annual profit when operating in full capacity.

Buses with higher load distribution factors (bold arrows in Fig. 4) are connected in metropolitan regions so that capital investments for enforcing transmission lines in those regions would be higher than the others. Such regions are indicated by "M" (representing Metropolitan) in Fig. 4.

A planning year is divided into four subperiods representing seasonal load patterns. We consider the following four cases to analyze the performance of the proposed planning model. The planning horizon is assumed to be ten years in all scenarios. The results are summarized in Table VII.

Case 1—Without Promoting IPP Investment: The annual peak demand increase is 2% in all seasons along the planning horizon. In this case the existing generators are sufficient to supply the forecasted demand. Given the low demand increase ratio, the planning model does not provide any incentives to IPPs. Transmission investments shown in Table VII are already sufficient to satisfy the security criterion while minimizing the investment cost and the transmission congestion level along the planning horizon. In other words, incentive payments required by IPPs are considerably high as compared to transmission investments.

Case 2—Promoting IPP Investment (Providing a More Economical Solution): In Table VI, the capacity of candidate generators is reduced from 300 MW to 100 MW so that the annual incentives are comparable with transmission investments. The

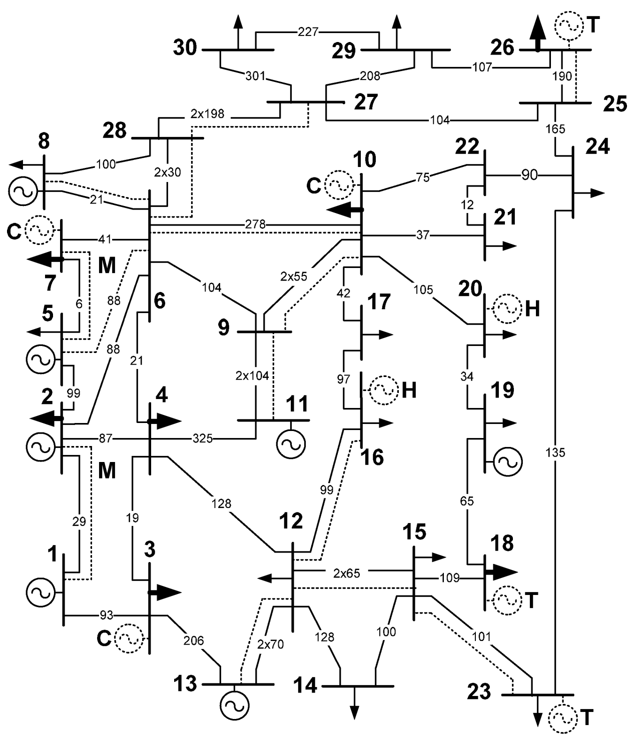

Fig. 4. Modified IEEE 30-bus system.

TABLE VII
RESULTS SUMMARY FOR 30-BUS SYSTEM

Case	API *	Investment **	TTIC ($M)	TIP ($M)	AOCC ($M)	TC ($M)
1	2%	$L_{9\text{-}10}$; Y_1 $L_{5\text{-}7}$; Y_2 $L_{9\text{-}11}$; Y_3	31.19	-	24.64	55.83
2	2%	$L_{9\text{-}10}$; Y_4 $L_{5\text{-}7}$; Y_5 $L_{9\text{-}11}$; Y_6 $G_{H,16}$; Y_1	20.45	≈ 5	21.40	46.85
3	5%	$L_{5\text{-}6}$; Y_1 $L_{5\text{-}7}$; Y_1 $L_{9\text{-}10}$; Y_6 $L_{9\text{-}11}$; Y_9 $L_{12\text{-}16}$; Y_{10} $L_{15\text{-}23}$; Y_{10} $G_{H,16}$; Y_2 $G_{H,20}$; Y_7	53.65	40.56	≈ 0	94.21
4	7%	$L_{5\text{-}6}$; Y_1 $L_{5\text{-}7}$; Y_1 $L_{9\text{-}10}$; Y_8 $L_{9\text{-}11}$; Y_7 $G_{T,26}$; Y_7 $G_{T,23}$; Y_{10} $G_{H,16}$; Y_5 $G_{H,20}$; Y_2	51.52	100.85	≈ 0	152.37

* API: Annual peak demand increase (%)
** $L_{i\text{-}j}$: Investment on Transmission line from bus *i* to bus *j*; Y_i: Year *i*; $G_{X,i}$: Candidate generator at bus *i* (X: generator type index)

TABLE VIII
30-BUS SYSTEM CASE 2: DISPATCH AND INCENTIVE PAYMENTS FOR $G_{H,16}$

Years		Y_1*	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	$Y_{9\text{-}10}$
Dispatch (MW)	S_1**	0	0	0	67	89	79	89	99	100
	S_2	100	100	100	100	100	100	100	100	100
	S_3	30	100	100	100	100	100	100	100	100
	S_4	100	100	100	100	100	100	100	100	100
Incentive ($M)		2.95	1.03	1.03	0	0	0	0	0	0
Advance contracts	$/MWh	24	19	19	0	0	0	0	0	0
	GWh	500	650	650	0	0	0	0	0	0

* Y_i: Year along the planning horizon
** S_i: Season in a year

other financial figures are fixed in Table VI. The planning result in Table VII shows that the investment on hydro generator at Bus 16 (i.e., $G_{H,16}$) in year 1 defers the transmission investment proposed in Case 1 while satisfying the security criterion with a reduced AOCC along the horizon.

The proposed dispatch for $G_{H,16}$ along the horizon and corresponding annual incentives are given in Table VIII. The generator is fully dispatched during peak demand seasons (i.e., S_2 and S_4) in each year which is not the case during the off-peak seasons. For the same energy sale price, the dispatch priority is given to existing generators considering their possible long-term contracts. Consequently, the incentive in initial years is due to the partial operation of $G_{H,16}$ during the off-peak seasons. An energy purchase agreement could be made in advance with the corresponding IPP to trigger the investment on $G_{H,16}$ in year 1. Table VIII shows the financial attributes of such agreements when considering the proposed method.

Cases 3 and 4—Promoting the IPP Investment (Supply/Demand Adequacy): The annual peak demand increase is assumed to be 5% in Case 3 so the total capacity of existing generators would not be sufficient to supply the forecasted demand along the planning horizon. Contrary to the previous cases, the generation investment is inevitable for satisfying the system security criterion. Assuming that the capacity of all candidate generators is again 300 MW, our planning model proposes a combination of transmission and generation investments shown in Table VII, which optimizes the TEP problem. Given their lowest energy sale prices, the hydro generators are given the priority not only for security concerns but also minimizing the congestion along the planning horizon. Indeed, the expected AOCC is zero under the proposed investments, as shown in Table VII.

The higher energy sale prices would promote investments on other types of candidate generators only if such investments contribute to the system security. In Case 4, the 7% annual peak demand increase would promote investments on thermal generators at buses 23 and 26 in addition to hydro generators to compensate for supply deficiency. Table VII shows the optimal investments and corresponding total costs along the planning horizon.

Further Discussions on the IEEE 30-Bus System: The IEEE modified 30-bus system example shows how incentives are prioritized among candidate generators to satisfy the system security and optimize TEP. The optimal investment which satisfies the system security criterion could also mitigate the transmission congestion along the planning horizon (Cases 3 and 4). On the other hand, when the installed capacity is sufficient, the investment on candidate generators would be promoted only if the incentives are comparable with transmission investments (Cases 1 and 2).

TABLE IX
FINANCIAL ASPECTS OF THE PROPOSED TENDER BETWEEN $G_{H,16}$ AND $G_{H,20}$

Incentive duration (years)		7
Total incentive along the planning horizon ($M)		43.5
Advance contract	MW	280
	TWh/year	2.25
	$/MWh	20.5

In the case of a single generator investment, bilateral energy purchase contracts are the obvious incentive mechanism as proposed in Case 2. Incentive payments are essentially based on the proposed energy sale prices of the corresponding IPPs. On the other hand, a tender could be opened in the case of multiple generators. The existing peaking generators in a region would contribute to the security and should be considered equally.

As shown in Cases 3 and 4, the incentive mechanism is more challenging when the candidate generators are at different regions and/or deserve incentive in different years. In Case 3 (with a 5% annual demand increase), both $G_{H,16}$ and $G_{H,20}$ contribute to the supply deficiency problem, although $G_{H,16}$ is promoted just two years after the initial year. In Case 4 (with a 7% annual demand increase), $G_{H,20}$ is promoted from the second year on. In Case 4, two more generators ($G_{T,23}$ and $G_{T,26}$) are proposed during the second half of the planning horizon. A tender may be opened based on the following considerations:

- The difference in the annual demand increase is just 2% between Cases 3 and 4. Therefore, the incentive mechanism should consider the Case 4 which is the worse Case in the sense of security concern.
- $G_{H,16}$ and $G_{H,20}$ should be considered equally given that they are in the same region (i.e., equal marginal contribution to security) and their energy sale price—and accordingly incentive requirements—are equal under the same dispatch.
- The incentive payment to $G_{T,23}$ and $G_{T,26}$ could be postponed since it is proposed after the seventh year (see Table VII, Case 4). That is, the incentive payment to the designated IPPs could be decided later. The load growth uncertainty along the planning horizon also supports this idea.

Consequently, the tender could be opened to sign contracts with IPPs of $G_{H,16}$ and $G_{H,20}$ for an investment in year 2. Table IX shows the financial aspects of such a tender. Note that the average energy purchase price is 20.5$/MWh which is higher than the 18$/MWh energy sale price envisaged by the IPPs to compensate the early investment. Furthermore:

- The 20.5$/MWh average energy price in Table IX ensures the required IPPs incentive for the 280 MW operation in seven years. The IPP could also participate in the ancillary service market and/or fulfill its reserve requirement by the remaining 20 MW capacity in Cases 3 and 4.
- Averaging the incentive mechanism to seven years is due to the fact that no additional investment is made by the market forces. Meanwhile, it will be necessary to open a second tender to ensure the security of the system under the worse annual load growth scenario.
- If both IPPs intend to make the contract shown in Table IX, an auction could be considered and the IPP which accepts the lower energy purchase price would take the higher risk.

IV. CONCLUSIONS AND REMARKS

In this paper, a multi-year TEP model is proposed which possible incentive payments to IPPs to trigger candidate generation investments. The purpose is to get an optimal planning solution when considering the system security and congestion along the planning horizon after the restructuring of power systems. The proposed approach would successfully to optimize the sum of investment cost of transmission lines, incentive payments to IPPs, and forecasted operation costs due to congestion along the planning horizon. The results of numerical examples (two-bus and the IEEE 30-bus systems) show the effectiveness of the proposed model.

The necessity of incentives to trigger IPP investments was evaluated within the TEP problem concerning the security and the congestion of grid along the planning horizon. The main idea is to trigger investments on IPPs earlier than those projected by the decentralized generation system, when the power system security is threatened. The case studies illustrate how the proposed planning algorithm could be utilized in order to determine incentive payments to candidate generators when necessary, and prioritize such incentives among multiple IPP candidates. The proposed planning model is applicable to restructured power systems, particularly during the market development phase when inherent uncertainties in existing policies and electricity prices due to the considerable share of state-owned generation companies could signal delays in investment decisions by IPPs.

The incentive offers to IPPs for advancing their generator investment plan is conceivable particularly when such investments are subject to low dispatch levels during initial years. For instance, peaking generators could contribute to the grid reliability, particularly during on-peak periods. Although they are expensive, system operators would appreciate the availability and the commitment of such units in emergency conditions. A considerable share of consumers would also prefer to pay extra instead of facing any interruptions. Accordingly, the following incentive mechanism could be proposed: either make a direct energy purchase contract with IPPs or open a tender among IPPs when fairness is a concern. Both incentive mechanisms should take into account the fact that incentive payments proposed by our planning algorithm depend on the energy sale prices provided by IPPs, as illustrated in Table VIII.

The proposed planning algorithm would be utilized by an independent authority that is responsible for the long-term security of the power system. Such an institution is assumed to be a state-owned transmission company in this paper, which is indeed common in most EU countries. The IPP decisions would be reviewed and regulated by the authority as an independent entity. Accordingly, the authority is responsible for both determining and offering the incentives or making direct energy purchase contracts with the qualified IPPs. The planning uncertainties including energy sale prices and the role of monopolistic state-owned transmission company are among IPPs' risk factors that could result in delays on generation investment decisions.

Given their contribution to both power system security and transmission investment cost reduction (not only by postponing the transmission investment but also by ensuring the optimum transmission/generation expansion planning), such incentive payments to IPPs should be recovered from consumer payments. Accordingly, the incentive payments could be considered as a parameter in calculating the transmission usage charge by consumers. They could also be considered as capacity payments by consumers, like the ancillary services payments which are also related to the system security. The distribution of incentive payments among the consumers is beyond the scope of this paper, and will be discussed in detail in a future study.

Although the proposed incentive mechanism may encourage IPPs to game the market by manipulating the incentive requirements, those payments will be rejected in the proposed algorithm by means of Benders cuts if better alternatives (transmission lines or IPPs) could be identified. On the other hand, the proposed planning model could be utilized to reveal market manipulations and measure the level of market competition, as illustrated in Section II (two-bus system, Case 2). Such issues should indeed be among the regulatory authority's main concerns when considering the system security. When the manipulation of incentives is a concern, the authority could make additional sensitivity analyses to evaluate the impact of energy price on the planning solution.

The numerical examples also illustrated how the risk of generator investments—due to low dispatch levels during initial years of the investment—could signal delays in IPP investments. The risk is demonstrated by providing IPPs the expected dispatch levels of the investments based on their envisaged energy sale prices. This indicator would essentially provide IPPs with important signals on their forecasted energy price and cover investment uncertainties considerably.

A future study could consider the impact of electricity price forecast uncertainties in electricity markets. The planning algorithm could be improved by considering the demand side management and load curtailment costs. In addition, generator planning criteria could be improved further by considering more sophisticated financial models. The net present value (NPV) approach considered in this paper would ensure a profit; however, it does not consider investment opportunities. The NPV could be positive while there is no optimal time for investment as there might be a chance to get larger NPVs by delaying the proposed investments.

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