PROVIDING LOCATIONAL MARKET SIGNALS IN THE CONTEXT OF COORDINATED MULTI-YEAR TRANSMISSION EXPANSION PLANNING

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ABSTRACT

This study discusses the current transmission expansion planning (TEP) approach in the Turkish electricity market and proposes improvements to adopt deregulated environment and provide locational market signals to trigger generation investment. Unbundling of investment decisions in the generation industry necessitates development of market mechanisms to provide effective locational signals for generation capacity additions in the country. Such mechanisms should be designed in the context of multi-year coordinated (generation & transmission) planning analysis in order to assure social optimum in the long-term.

I. INTRODUCTION

Transmission expansion planning (TEP) is the process of designing future network configurations that meet predicted future needs. Traditionally, utilities have served peak demand by building central generation and transmission infrastructure. The coordination between generation resource and transmission planning was to minimize the operation cost and investment involving new generating units and transmission lines while satisfying the system reliability. A more holistic approach, referred to as integrated resource planning, considers additional alternatives such as demand-side management and distributed generation. Essentially, under coordinated planning approach, peak load can be served at a lower overall cost along the planning horizon, by utilizing a combination of expansion options.

The liberalization and restructuring process worldwide have introduced new complexities to the TEP problem [1]-[3]. This movement introduced competition at the extreme activities of the industry (i.e., generation and retailing) while keeping network transmission and distribution areas as natural monopolies. TEP must now be prepared in a decoupled way from generation and distribution despite their natural and indispensable dependency. This means that, in some way, transmission networks will now have to run after new users both at the generation and the demand side, introducing a new level of uncertainty regarding the TEP. The increasing number of distributed generators (e.g., coherent power plants, wind farms, mini-hydros, etc.) will create new challenges to transmission planners who should develop new strategies in order to plan the network in most proper manner (i.e., optimal).

The ability of transmission planners and regulators to control the direction of the companies' investments towards the desired social optimum is among the major challenges after the deregulation of generation industry. Some mechanisms have been introduced worldwide to trigger generator investments, not only to mitigate the uncertainties in some degree, but also to guide the market in order to achieve social optimum. An example can be given from Turkey where the entire transmission network is separated into different zones of use-of-transmission system charge with a uniform tariff within each zone. However, according to the recent regulatory figures, the mechanism has not provided sufficient incentive for generation companies since its procurement [4], [5].

This paper discusses the existing TEP methods and possible improvements for providing locational market signals to adopt deregulated environment and trigger generation investment in the Turkish electricity market. Unbundling of investment decisions in the generation industry necessitates development of new mechanisms to provide effective market signals for generation capacity additions in the country. Such mechanisms should take into account the assessment of coordinated planning (generation and transmission in a coordinated way) in order to reach social optimum in the long-term. Ignoring generator investment decision in the perspective of TEP most probably results in either over-investment in transmission network or realization of non-optimal generation investment in the sense of time and location, both of which increase the total social cost along the planning horizon.

II. CURRENT SITUATION IN THE TURKISH ELECTRICITY MARKET

In Turkey, the state-owned transmission company (TEIAS) has a monopoly to operate and expand transmission network to meet the needs of market participants. In order to carry out its duties, the company is required to prepare detailed investment plans and a capital expenditure budget. The plans and the corresponding budget are reviewed by the market regulator (EPDK). The proposed investment cost is recovered through use-of-transmission system charges (i.e., access charges) according to the location of customers within the grid based on the investment cost-related pricing (ICRP) approach described in [6]. Although the approach is proposed to send long-term positioning signals to new market participants, it has not provided sufficient incentive since its procurement according to the regulatory figures. The followings are among the main drawbacks of the mechanism.

The transmission system pricing concept is based on the current situation of the network. That is, marginal increase of demands on the current topology of the power system determines the price differentials between buses. Therefore, the prices should be updated in case of any significant topological changes in the system such as transmission enforcements and generator investments. Determination of the price update period is a challenge in this approach given the possible significant effect of price upgrade on the existing transmission users. In addition, ignoring the possible effects of potential generator investments' together with the transmission investment decisions in the planning horizon, the method does not provide the effective marginal prices [7].

The pricing method does not take into account transmission bottleneck conditions. The experience in countries like UK, which utilizes the same transmission pricing method, show that market participants may prefer to locate new gas-fired power plants in congested areas, in spite of their high access prices. Some form of location-based security and/or congestion pricing might be included in the overall transmission pricing design to facilitate both transmission and generation investment decisions effectively [8]. A proper transmission-pricing scheme that considers transmission constraints could motivate new transmission and/or generating capacity investments for improving the electricity market efficiency and perhaps prevent gaming in a volatile market possible in the future.

Based on the considerations above, the following suggestion can be made. Possible bottlenecks of the transmission system in the future based on the tendency of generator investments and load demand forecast, and potential reinforcements (transmission and/or generator) that may affect those bottlenecks should be investigated within the TEP problem in order to provide more effective locational signals. This is among the major challenges that the transmission company has to deal with after the electricity restructuring in Turkey. The following section reveals the importance of this issue.

TRANSMISSION PLANNING APPROACH

Power system planning is a complex process that requires a significant amount of work, involving major stages such as system reliability assessment, forecasting of demand and fuel prices, and security assessment. Long-term power transmission network expansion planning problem consists of choosing expansion plans, from a predefined set of candidate circuits, those that should be built in order to minimize the investment and operational costs, and to supply the forecasted demand along the planning horizon. It involves a series of studies whose purpose is to determine when and where to install new equipments/lines. The initial candidate pool for expansion is generally formulated based on both the characteristics of the given system, such as the generation and transmission capacity, load and energy price forecasts, transmission tariff and its diversity, etc, and the human knowledge based on practical engineering, such financial limits, estimated construction periods, environmental factors, etc.

Broadly, network expansion planning can be classified as static and dynamic according to the treatment of the study period. The planning is static if the planner seeks the optimal circuit additional set for a single year on the planning horizon, that is, the planner is not interested in determining when the circuits should be installed but in finding the final optimal network state for a future single definite situation (static situation). On the other hand, if multiple years are considered, and an optimal expansion strategy is outlined along the whole planning period, the planning is classified as dynamic (i.e. year by year expansion plan). In this case the coupling among the interior years makes the problem more complex. In fact, an investment scheduled for a particular year can have a positive impact in years afterward and can also contribute to solve problems elsewhere in the system, given the interconnected nature of transmission networks.

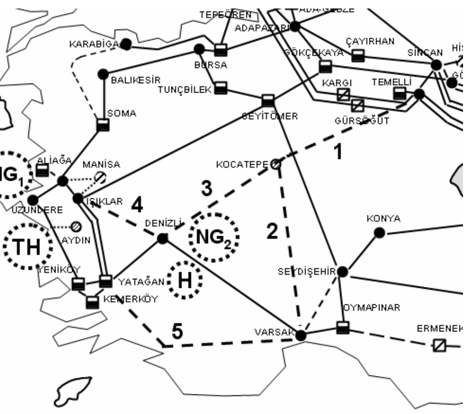

Fig. 1. Southwest region of the Turkish Power System (380 kV).

In Turkey, static planning approach is utilized in TEP under the strong uncertainty in generation after opening the market to competition in the generation segment. Currently, the company has been dealing with the planning of the southwest region of the country's power system. According to demand projections based on current high demand increase rate with about 7% per year, some measures should be taken to ensure the supply reliability at the region within a foreseeable future. Single line diagram of the system (380 kV network only) of the region is given in Fig. 1. The solid lines correspond to existing 380 kV lines, and the dashed lines correspond to candidate reinforcements foreseen by the company. Dashed circles correspond to potential generator investments whose source types are marked inside the circle (H: hydro, NG: natural gas combined cycle, and T: thermal).

The long-term transmission plan should define the optimum investment schedule along the planning horizon, which depends strongly on the generation investment decisions as well as the load demand forecast. The indicated uncertainties in the generation essentially complicate the planning for the region. Total number of scenarios increases too much if all possible investments are considered. Multi-year coordinated planning should be investigated in order to reveal the effect of those uncertainties on the optimum investment planning. The following section illustrates the importance of such planning.

III. MULTI-YEAR COORDINATED PLANNING APPROACH

The coordination between generation and transmission planning is to minimize the operation cost and investment involving new generating units and transmission lines while satisfying the system reliability. The literature regarding TEP problem includes many studies that take the energy cost of the generators as the operational cost [9]. The following subsection presents this approach within a long-term multi-year planning problem.

INVESTMENT & OPERATIONAL COST

The simple two-bus system depicted in Fig. 2 enables easy understanding of the importance of the multi-year planning approach. In this example, the generator at Bus 1 is supplying the load at Bus 2 through the transmission line. The solid line corresponds to existing transmission line, and the dashed line corresponds to candidate reinforcement along the planning horizon. Multi-year coordinated planning approach assesses the investment of the second transmission line taking into account the possible local generation at Bus 2 (the dashed generator).

Fig. 2. Two-bus system.

The followings are among the conditions which the investment decision (i.e., timing) of the second transmission line depends on; peak demand increase, load duration curve, planning horizon, capital and energy (operational) costs of both transmission line and the local generation under decision. Optimum investment schedule in terms of timing can be determined along the planning horizon based on those technical and financial assumptions which may considerably influence the optimum planning schedule.

The energy cost is proportional with the area under the load duration curve (i.e., consumed energy). Strictly speaking, the operational problem needs to be solved for each hour throughout the years along the planning horizon in order to calculate the expected values of operational cost. In addition to the computational problems, this requires the representation of all supply energy costs for each individual hour. This is obviously a huge burden. This requirement may, however, be softened by taking advantage of possible hourly and seasonal patterns. It may be possible to estimate the whole year for planning purposes. The load can be represented by an average value in each year in calculating the operational cost. This is illustrated in Fig. 3 which represents daily load curve of a typical load. Assuming the peak demand along the day as the base load (i.e., 1 pu), the area under the 0.7 pu line is equal to the area under the daily load curve. In other words, the daily energy consumption of this typical load can be represented by the average load of 0.7 pu. This example illustrates the requirement for splitting the load periods in sufficient amounts to represent the operation cost accurately.

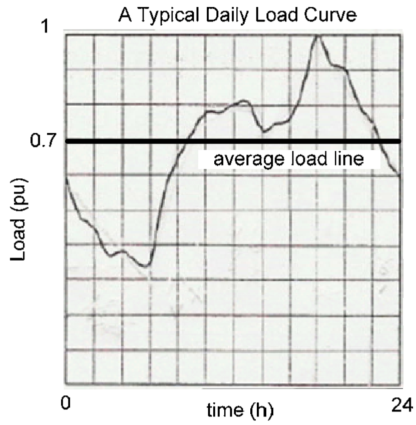

Fig. 3. Representation of the average load for a typical day.

The following section discusses the utilization of congestion cost - instead of total energy cost - within the planning problem. In this case, representation of load forecast is easier given that the congestion occurs only during peak conditions (daily and/or seasonal). This is illustrated in Fig. 4 which depicts the average load during peak time. Given that congestion on transmission grid occurs during peak loading conditions, congestion cost in the grid can be estimated by taking the average demand value of the load buses during peak conditions. The average load value is in general very close to the peak load value, and this enables more realistic estimation of the demand and simplifies the formulation of the problem. For example, in the case of southwest region of Turkey, which encloses the most touristy region of the country during long summer season, forecasted peak demand duration can be assumed to be roughly four months per year with almost constant demand.

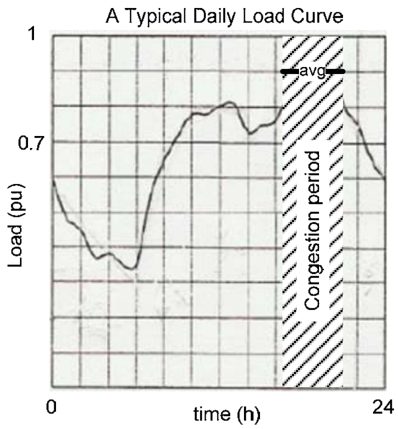

Fig. 4. Representation of the congestion period in a typical day.

INVESTMENT & CONGESTION COST

The scarcity of transmission capacity and the demand for power generation from less expensive sources usually lead to transmission system congestion. When congestion occurs, generation (and/or load) has to be re-scheduled to ensure the system security. Essentially, re-scheduling could cause operating costs to increase. Congestion can also be relieved in long-term by transmission capacity expansion. In either solution, congestion management involves both economical and technical issues that require analyses of system conditions at present, as well as conditions that could occur due to the future growth in the system. Congestion costs provide economic information concerning the need for and the location of transmission enhancements.

Under the concept of "regulated revenue" approach, which many regulators have been inclined to use worldwide to regulate the monopoly transmission company (inc. Turkey), there is no incentive to reduce the congestion, given that the income granted to the transmission provider is constant irrespective of the performance of the transmission system. Essentially, it is challenging to overcome this obstacle by a common approach since all models adopted worldwide have their own attributes. Providing system reliability, on the other hand, is one of the major responsibilities of the system operators regardless of the institutional model adopted. To address the problem of transmission congestion, the U.S. Secretary of Energy chartered an Electricity Advisory Board that established a Transmission Grid Solution Subcommittee. The report from this subcommittee defines transmission congestion or "bottlenecks" as follows: "Bottlenecks occur when the system is constrained such that it cannot accommodate the flow of electricity and systematically inhibits transactions. Thus, a bottleneck has economic and/or reliability impacts" [3]. Consequently, transmission congestions clearly affect system reliability, and therefore, should be considered in planning decisions. Balancing of congestion level against network expansion investment cost to alleviate such congestion is becoming more topical issue today than before [10].

IV. PROBLEM FORMULATION

The objective of the proposed planning approach is to minimize the congestion cost and investment involving new generating units and transmission lines while satisfying system security based on single contingency (i.e., N-1) along the planning horizon:

$$Min \quad \sum_{t}^{T} TIC_t + \sum_{t}^{T} GIC_t + \sum_{t}^{T} CC_t \qquad (1)$$

where; TIC_t, GIC_t, and CC_t correspond to total transmission investment cost, total generation investment cost and total congestion cost in year t, respectively, and T corresponds to the planning period. Each year could be further divided into subperiods. The investment planning problem (1) is subject to both planning and system constraints. Budget constraints such as the availability of capital investment funds could be incorporated in planning constraints. System constraints are the well known load-flow problem constraints including Kirchhoff's first and second laws. N-1 security constraint is to satisfy the nodal power balance while maintaining the single contingency.

The impact of congestion in this approach is a sort of the inhibition of most favorable transactions expected within the planning horizon due to transmission constraints. In many of such countries, like Turkey, the restructuring starts with unbundling the generation segment and introducing a wholesale electricity market based on bilateral contracts that match the generation companies and large scale consumers through wholesale trading companies. The number of bilateral transactions grows with the addition of new agents as the market matures, and this considerably challenges the system operation. Bilateral contracts should have to be honoured and executed by the transmission company unless the system security is endangered. The success of the restructuring efforts depends on the "availability" of the transmission network that permits development of a competitive market. The economic dispatch solution of the unconstrained network, in which no transactions can be inhibited due to transmission congestion, might give the minimum reference cost for the calculation of the cost of possible transaction inhibitions (i.e., congestion cost).

Because of the combinatorial nature of the problem, solving the multi-year transmission expansion planning problem is very hard task. A major difficulty in obtaining global optimum solution for complex, real-life networks is due to the nonconvexity of the network expansion problem (i.e. only local optimal solutions are guaranteed). Among all combinatorial optimization techniques used, Benders decomposition have been used with success in determining static expansion planning since its first application to this problem. In this approach, utilization of hierarchical decomposition techniques has proved to be an efficient heuristic for coping with nonconvexity [11]. Future studies will include adopting the security constraint to this optimization technique.

V. CONCLUSION

After restructuring of power systems and deregulation of generation segment, the potential gains from local generator investments should still be evaluated within a multi-year coordinated planning problem. Given that the coordinated planning should consider the technical and financial constraints which are quite country specific, such planning should be performed by an independent institute that favors the social cost in the long-term. The results can be utilized in developing incentive mechanisms, such as capacity payments, to trigger early investments to facilitate decentralized generation investment when necessary.

According to the current regulations, the transmission company of Turkey has to submit a document of "connection opportunities" for each planning horizon to inform the market players about the transmission system condition and give signals to direct investments. This document should be prepared in the context of a multi-year coordinated planning. Given the fact that the success of restructuring efforts depends on the "availability" of the transmission network that permits development of the competitive market, transmission congestions possible in the future should be considered within the planning problem. The annual evaluation of transmission investments and congestion costs along with local generation investment costs will enable more realistic assessments of generation and transmission investment decisions for the country.

Future studies will include development of a planning framework that concerns with both the security of the network and the transmission congestions possible along the planning horizon. The results will be utilized in developing locational market signals along with the transmission pricing.

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