Analyzing the Current U.S. Electricity Transmission System and Its Main Caveats to Incentivize Long-term Investments

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***Abstract*—This paper explains the way in which the current U.S. electric system contains insufficient incentives for long-term investments in transmission. Moreover, it highlights some key issues that should be considered to improve these investment incentives. The paper shows that, under the current U.S. transmission system, independent merchant investors, transmission rights' holders, and generation firms may have disincentives for making socially beneficial transmission investments.**

***Index Terms*—Network expansion planning, power system economics, transmission investment incentives.**

I. Introduction

THE electricity transmission system is the cornerstone on which supply-demand coordination depends. It is an extensive system of interconnected networks in which high-voltage power lines transport electricity from generators to consumers. A critical early decision to rely on alternating current (AC) technologies for high-voltage transmission has led to the construction of three major interconnected power systems in the U.S.: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT) interconnection. Within each system, it is very important to perform accurate frequency and voltage synchronizations because disturbances are felt nearly instantaneously throughout the system. This interdependence leads to reliance on well-coordinated actions among its users to ensure reliability.

In the U.S. electric system, virtually all utilities are interconnected with at least one other utility by some major transmission networks. These interconnections are divided into 152 regional "control areas". A control area is a portion of the system (lines, transformers, generators, loads, and other equipment) under the supervision and control of a single operator (or group of operators at a single location or under a single administrative structure). Control areas are the primary units responsible for the reliable operation of the transmission system. They must designate the generators to operate (unit commitment problem), schedule power trades between control areas (transaction scheduling problem), and schedule electricity generation from each generator (unit dispatch problem) in a way that ensure reliability of the electric system of that area.

In the U.S., there is separation between ownership and control of the transmission assets. Accordingly, each control area is under the supervision of an Independent System Operator (ISO) that "controls" the operations in that area. At the present, although each ISO has different responsibilities, all ISOs meet the federal requirement that all market participants have nondiscriminatory, open access to the transmission system.

Much of the currently observed underinvestment in electricity transmission is a consequence of the poor incentive structures present in the U.S. system. Generation-unit owners profiting from congestion have no incentive to support transmission upgrades. Electricity retailers bundle congestion charges into their cost of purchasing wholesale electricity. Transmission owners receive a regulated rate of return on their network investments. While consumers would like economically beneficial upgrades to occur, individually they have little incentive to participate in the process.

One of the basic problems is that locational marginal price signals, which are thought to be the best indicators of the effectiveness of investment incentives, are not sufficient to motivate investments in transmission. Locational marginal prices are hypothetically derived from the maximization of social welfare done by a system operator. In theory, each of these market prices is the intersection where the marginal cost of generation equal the price that the last consumer served is willing to pay. Thus, by allowing transmission prices to be higher in areas where transmission resources are scarcer, locational marginal prices should create the correct incentives to invest in: (i) generation to compete with existing resources in higher-cost areas, (ii) transmission to facilitate competition from resources outside the constrained areas, and (iii) demand responsiveness capabilities to enhance demand-side elasticity in response to higher prices. However, market power issues and other market imperfections, together with the fact that electricity must be produced at the same time that it is

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consumed, cause locational marginal price signals to not create sufficient incentives for long-term transmission investments.

No many authors have thoroughly studied the problem of the insufficient incentives for investment in the U.S. electricity transmission system.

The rest of the paper is organized as follows. Section II contains a brief description of the current U.S. electricity transmission system and its main caveats to create the correct incentives for efficient investment and operation. In Section III, we study the incentives for transmission investment of three types of market participants: holders of financial transmission rights (FTRs), independent merchant investors, and generation firms. Section IV concludes the paper.

II. The Current U.S. Electricity Transmission System and its Main Caveats

Henceforth, by “the current U.S. transmission system” we will understand a transmission system that uses nodal pricing method, employs financial transmission rights (whose holders are rewarded based on congestion rents), and rewards network investments based on rate-of-return regulation administered by a non-profit ISO, which manages transmission assets owned by many investors. The main two reasons for this choice are: (i) many of the U.S. transmission systems actually use this type of scheme and (ii) this structure has recently been proposed by the Federal Energy Regulatory Commission (FERC) as part of its Standard Market Design [1].

Next, we describe some properties of the current U.S. transmission system that induce disincentives for efficient investment.

A key problem of the current US transmission system is the potential mismatch between the rewards for and benefits from transmission investment due to the “arbitrariness” in the settling of the rate of return that rewards investments. Before an investment in the network is made, investors need to acquire from regulators a “Certificate of Public Convenience and Necessity”. Once this is accomplished, investors are guaranteed recovery of all the “prudently incurred” investment costs through the rate-base and other transmission related revenues. Each year, the base rate of return is reduced by both depreciation and any remaining book value of the assets that are taken out of service, and is increased by the allowed costs of the assets put into service. At the time an investment is put into service, the regulator decides how much of its investment costs, including interest paid during construction, were prudently incurred (given what the investor knew, or should have known, at that time); and only these prudent costs are considered into the base rate of return. However, these costs could be misaligned with the real transmission capacity added to the network. For example, both an investment involving upgrades of existing facilities and an investment involving the construction of a new transmission line could add similar transmission capacity to the grid although the investment costs would be substantially different. Consequently, the rate of return that rewards transmission investments could be poorly correlated with the real benefits from those investments. This potential mismatch between the rewards for and benefits from transmission investment could lead to inefficient network expansions.

Related to the previous problem is the drawback that line capacities are generally assumed being well-defined and non-stochastic amounts (this fact was pointed out by Joskow and Tirole [2]). However, the physical capacity of transmission lines changes continuously depending on temperature and other exogenous parameters (environmental parameters, random outages, etc.). This fact strengthens the idea that the rate of return that rewards transmission investments can be poorly correlated with the real transmission capacity added to the network. Therefore, it could also conduct to the improper alignment between investment incentives and the social benefits from those investments.

Other limitation of the current U.S. transmission system is the difficulty for investors to capture other revenue streams (no derived from rewards based on rate-of-return regulation) resulting from transmission investment. This is because of the public-good nature of transmission investments, which allows, for example, that generators separated from load by transmission constraints also benefit from transmission expansions. Thus, even when all beneficiaries are willing to participate in the expansion, if the benefits are distributed asymmetrically, it might be difficult for the beneficiaries to reach agreement about benefit shares and hence cost shares.

On the other hand, the current U.S. transmission system rewards financial-transmission-rights’ holders (FTR’s holders) based on congestion rents. Given that efficient nodal prices contain network congestion and loss components and FTR’s holders collect revenues based upon these prices (based on congestion rents), FTR’s holders could have incentives to increase, rather than reduce, congestion and losses in the transmission system. Therefore, because congestion rents can be poorly correlated with congestion costs (which are the real benefits/costs to society), FTR’s holders could have little incentive to make socially efficient transmission investments. This fact is illustrated in Section III of this paper in the case of a three-node network.

Moreover, the presence of network externalities, lumpiness of transmission investment, and the inherent barriers to entry along a given transmission path complicate the situation. As we show in Section III, under some conditions, a new network investor (who is rewarded based on rate-of-return regulation) could have incentives to decrease the social welfare by making detrimental investments that increase the network congestion and impose obligations over the existing generation firms and transmission owners.

Another problem of the current U.S. (and probably any) transmission system is the fact that decisions about transmission investment are made in a political context. This is a difficulty mainly because transmission investment has important distributional impacts. The key issue is that while society as a whole may benefit from the elimination of congestion, some parties may be harmed. In general, transmission investment effects rent transfers from load pocket generators and generation pocket consumers to load pocket consumers and generation pocket generators. However, load pocket consumers and generation pocket generators cannot simply decide to build a line linking them. Their decision will be subject to scrutiny by not only an ISO, but also state and federal energy and environmental regulators. In this type of environment, the "losers" from transmission investment can be expected to expend up to the amount of rents that they stand to lose to block the transmission investment. This rent dissipation is wasteful. Moreover, it may block good projects from being built. Reference [3] contains an example that illustrates this idea.

Nevertheless, it is also worth to mention some characteristics of the current U.S. transmission system that discourage its efficient operation (because an inefficient operation of a transmission system directly affects the investment incentives in that system). Next, we present the main caveats that discourage an efficient operation.

One of the biggest operational problems of the current U.S. transmission system is that rate-of-return regulation offers insufficient incentives for transmission utilities to reduce costs aggressively. This is because, under the rate-of-return regulation scheme, transmission utilities cannot realize any extra gain from efficiencies achieved. The root of the problem is that , under the current U.S. transmission system, ISOs provide ancillary services, loss compensation and congestion management almost totally independent of who own transmission lines. This no relationship between transmission ownership and uplift services yields to a disincentive for transmission owners (TOs) to engage in activities leading to reductions either in the costs of the grid or in the congestion (re-dispatch) costs.

Likewise, the current U.S. transmission system does not provide TOs with economic incentives to perform high-quality maintenance of their transmission lines. Again, this is basically because TOs are not allowed to retain any portion of their cost savings as additional profit. In other words, if a TO took some actions to improve the capacity of her transmission lines (as cleaning the areas surrounding the power transmission towers or cutting the trees in the neighborhood of her transmission lines), then she would not receive any direct reward for doing that effort. A solution to this problem would be the implementation of a scheme where ISOs rate the nominal line capacities and run auctions for the surplus capacities provided by TOs, where TOs assume the responsibility of a failure due to an overloaded transmission line.

Moreover, the allocation of financial transmission rights can be subjective and inefficient. Generally speaking, ISOs make judgmental decisions about the total transmission capacity available in the system. For instance, when storms approach and the likelihood of one or multiple outage increases, an ISO could decide to leave a large amount of unemployed (reserve for contingencies) transmission capacity to ensure reliable operation of the system. Because the incentives that ISOs have to prefer one point of operation to others are not always clear, the amount and allocation of financial transmission rights the ISOs assign could be socially inefficient.

Other operational impasse of the current U.S. transmission system is the potential over-scheduling problem associated with the Transmission Loading Relief (TLR) method employed by most of the congestion management protocols in the U.S. The TLR is a method, applied by ISOs, for curtailment of transactions that violate security rules. A key issue in the implementation of the TLR is how the re-dispatch costs are being recovered. These costs can either be absorbed as part of the system operation costs (and be shared by all participants) or be charged to those "responsible" for the need of incurring into re-dispatch costs. In general, it is more efficient to avoid the sharing of expenses among all market participants because this tends to create incentives to overschedule transactions. Such over-scheduling problem has the potential of detracting from system reliability and no contributing to the economic efficiency of the system operation. However, identifying the responsible for the need of incurring into re-dispatch costs may be a really hard, if not impossible, task.

Other caveats of the current U.S. transmission system are the relatively high regulatory costs and the potential incentive for the regulated entities to engage in costly activities designed to influence the regulator. In fact, rate-of-return regulation requires an expensive effort to obtain detailed industry data. Furthermore, regulators always suffer from a disadvantage given that any information they obtained from the regulated industry is always incomplete relative to the information held by the industry, leaving the regulator in an inferior negotiating position relative to that of the industry.

In November of 2005, FERC proposed a Notice of Proposed Rulemaking (NOPR) on promoting transmission investment through pricing reform, which attempts to address some of the problems mentioned above [4]. Basically, FERC proposes an increase in the rate of return on equity (ROE), especially for stand-alone transmission companies (transcos), in order to both attract new investment in transmission facilities and encourage transco formation. This FERC's proposal is based on the idea that incentives may be more effective in fostering new transmission investment for transcos than for traditional public utilities that are dependent upon retail regulators for some portion of their transmission rate recovery. Due to their structure, transcos have incentives to better manage transmission assets, have incentives to develop innovative services, and may have better access to capital markets than public utilities given a more focused business model. Moreover, because transcos' sole focus is on the business of transmission, they may be in a better position to respond to market signals that indicate when and where transmission investment is needed, and, therefore, are more likely to yield additional capital investment in transmission. In other words, transcos may allow a better match between the rewards for and benefits from transmission investment (which may eventually lead to efficient network expansions) than traditional public utilities.

III. Investment Incentives of the Market Participants

In the previous section, we identified the main characteristics of the current U.S. transmission system that induce disincentives for efficient long-term investment. In this section, we show, through simple examples, that different types of market participants – holders of financial transmission rights (FTRs), independent merchant investors, and generation firms – may have disincentives to make socially efficient transmission expansions.

A. Investment Incentives of FTR's Holders

Locational marginal pricing approach has several advantages. However, a key concern about applying this method to electricity transmission services is the incentives created for parties making investment in the grid. One of the fundamental problems is that efficient nodal prices contain both network congestion and loss components. If the holders of FTRs collect revenues based upon these prices, they may have incentives to increase, rather than reduce, congestion and losses. This idea manifests itself even in a simple radial system. Accordingly, we shall use a simple three-node network to illustrate this fact.

Consider a radial network with two supply nodes serving a single demand node, as shown in Fig. 1. In this network, we assume that nodes 1 and 2 are the supply nodes and that node 3 is the demand node. We also assume that the generation capacity is unlimited at both supply nodes. Moreover, assume that the marginal costs of supply at nodes 1 and 2 are constant and equal to c_1 = \$20/MWh and c_2 = \$40/MWh, respectively. For simplicity, suppose demand is perfectly inelastic and equal to 300 MWh. The thermal capacities of lines (1,3) and (2,3) are 150 MW and 300 MW, respectively. To keep the example simple, we assume that all transmission lines have identical electrical characteristics (i.e., line impedance) and that transmission losses are negligible.

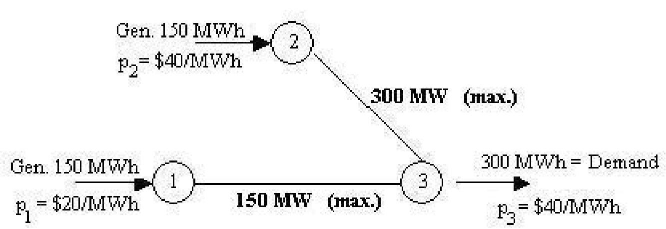

Fig. 1. Incentives for grid expansions in a radial network with two supply nodes serving a single demand node.

Assume generation firms are perfectly competitive so that nodal prices equal the marginal costs of generation (or marginal benefit of consumption) at each node of the network. From a social-planner viewpoint, one would like to meet the demand at node 3 with as much as possible of the cheaper generation at node 1. However, line (1,3) allows only a flow up to 150MWh. Thus, as Fig. 1 suggests, the optimal dispatch, in this case, is to allow 150MWh of generation at each supply node. Note that, under the optimal dispatch, the marginal benefit of demanding one extra MWh of power must equal the marginal cost of generating one extra MWh of power at node 2 (because extra-generation at node 1 is not feasible). Under this optimal dispatch, the holder of the FTRs from node 1 to node 3, say TO(1,3), collects \$3,000/h (= [\$40/MWh – \$20/MWh] times 150 MWh) while the holder of the FTRs from node 2 to node 3, say TO(2,3), does not receive any rent for the use of her rights (because the corresponding nodal price difference is zero).

Now, suppose we want to increase the social welfare of the system by decreasing the congestion in line (1,3). Moreover, assume that, because of the lumpiness property of transmission investment, it is only possible to raise the thermal capacity limit of line (1,3) by fixed bundled amounts of 200 MW. Fig. 2 shows the modification of Fig. 1's network when raising the thermal capacity limit of line (1,3) up to 350 MW. Now, the entire demand can be satisfied by the cheaper generation at node 1. Moreover, under the new optimal dispatch, nodal prices at nodes 1 and 3 must be equal because the marginal benefit of demanding one extra MWh at node 3 equals the marginal cost of generating one extra MWh at node 1 (i.e., p_1 = p_3 = \$20/MWh). As consequence of these new nodal prices, all FTRs become worthless: TO(1,3) does not collect anything because the corresponding nodal price difference is zero and TO(2,3) does not receive anything because there is no flow on this link. Consequently, FTRs' holders have no incentive to invest in this modification, even though may be socially efficient, because the resulting transmission rights are worthless.

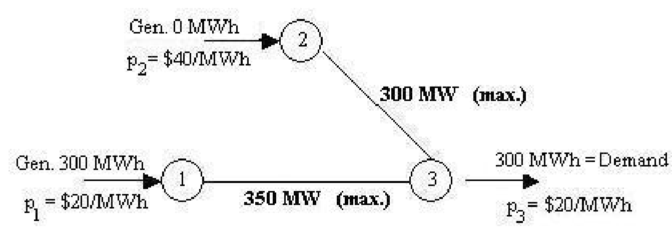

Fig. 2. Impact of the additional capacity in line (1,3).

B. Investment Incentives of Independent Merchant Investors

As mentioned in Section II, the presence of network externalities, lumpiness of transmission investment, and the inherent barriers to entry along a given transmission path, which tend to prevent a single transmission path from having a number of competing owners, complicate the analysis of the investment incentives of the market participants. Indeed, under some conditions, an independent merchant investor may have incentives to build a line to be intentionally congested, and profit from it, even though the social welfare of the system as a whole would decrease due to the congestion. To illustrate this idea, we employ the same three-node network used in the previous subsection.

Consider an independent merchant investor who modifies the network in Fig. 2, which has no congestion at all, by building a low-capacity line connecting the two supply nodes as shown by the network in Fig. 3. Suppose the thermal capacity of this new line is 33.3 MW. In this case, the addition of this new line imposes a reduction (relative to Fig. 2's network) in the maximum power that can be transferred from node 1 (the cheaper supply node) to the demand node. Specifically, according to Kirchoff's law, the generation firms located at node 1 can only supply 100 MWh without imposing an obligation over the generation firms at node 2 because of the thermal capacity limit of line (1,2). Over this amount, each MWh generated at node 1 must be compensated with a MWh produced at node 2 to satisfy the thermal capacity constraint of the new line. Thus, in this new network, the optimal dispatch is to generate 200 MWh at node 1 and 100 MWh at node 2 as shown in Fig. 3. Moreover, because of the congestion in the new line, the resulting nodal prices are p_1 = \$20/MWh, p_2 = \$40/MWh, and p_3 = \$30/MWh although lines (1,3) and (2,3) are not congested. Therefore, assuming the independent merchant investor is rewarded based on rate-of-return regulation (as it occurs in the current U.S. transmission system), she may find profitable to make this detrimental network expansion, which increases congestion and, in this way, the end-users' electricity price. Even worse, if the independent merchant investor were rewarded with FTRs corresponding to her investment (i.e., 33.3 MWh from node 1 to node 2), then she would collect extra revenues from the transmission business (she would get [\$40/MWh – \$20/MWh] times 33.3 MWh). This fact makes evident that, under the conditions assumed in the network in Fig. 3, an independent merchant investor could have incentives to increase the network congestion, imposing obligations over existing generation firms and transmission owners and decreasing social welfare.

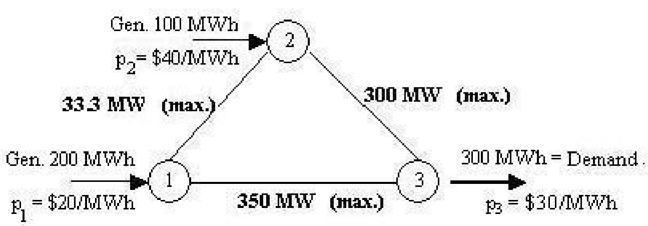

Fig. 3. Impact of the additional line (1,2).

C. *Investment Incentives of Generation Firms*

To show that both FTRs' holders and independent merchant investors may have disincentives to make socially beneficial transmission investments under the current U.S. transmission system, it is not relevant the consideration of the potential exercise of local market power by generation firms. Accordingly, for simplicity, we assumed perfectly competitive firms in the previous two subsections. However, when analyzing the investment incentives of generation firms, the possibility of exercising local market power becomes crucial. The key issue is that the exercise of local market power by generation firms may alter the firms' transmission investment incentives. Reference [5] studies this idea in the context of a radial (two-node) network. The analysis shows not only that generation firms with local market power may have disincentives to make socially beneficial investments in a transmission network, but also that if a generation firm with local market power holds FTRs, then these transmission rights could enhance its local market power.

IV. Conclusions

This paper explained the way in which the current U.S. electric system contains insufficient incentives for long-term investments in transmission. The main shortcomings of the current U.S. transmission system are the potential mismatch between the reward for (based on rate-of-return regulation) and the benefits from transmission investments, the arbitrariness in the settling of the rate of return that rewards transmission investments, the complexity of the political context in which decisions about transmission investments are made, the scarcity of incentives that transmission utilities have to both reduce network costs and perform high-quality maintenance of their transmission lines, the arbitrariness and probable inefficiency of FTRs' allocation procedures, the potential over-scheduling problem associated with the Transmission Loading Relief method, and the relatively high regulatory costs.

A solution to the problem of insufficient economic incentives for TOs to perform high-quality maintenance of their transmission lines is the implementation of a scheme where ISOs rate the nominal line capacities and run auctions for the surplus capacities provided by TOs, where TOs assume the responsibility of a failure due to an overloaded transmission line.

This article shows that, under the current U.S. transmission system, independent merchant investors, financial transmission rights' holders, and generation firms may have disincentives to make socially beneficial transmission investments. In the case of the first two types of market participants, the disincentives to make socially beneficial transmission investments manifest themselves even without considering the potential exercise of local market power by generation firms. However, when analyzing the investment incentives of generation firms, the possibility of exercising local market power becomes crucial.

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