A Nash Approach to Planning Merchant Transmission for Renewable Resource Integration

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***Abstract*—Major transmission projects are needed to integrate and to deliver renewable energy (RE) resources. Cost recovery is a serious impediment to transmission investment. A negotiation methodology is developed in this study to guide transmission investment for RE integration. Built on Nash bargaining theory, the methodology models a negotiation between an RE generation company and a transmission company for the cost sharing and recovery of a new transmission line permitting delivery of RE to the grid. Findings from a six-bus test case demonstrate the Pareto efficiency of the approach as well as its fairness, in that it is consistent with one commonly used definition of fairness in cooperative games, the Nash cooperative solution. Hence, the approach could potentially be used as a guideline for RE investors. The study also discusses the possibility of using RE subsidies to steer the negotiated solution towards a system-optimal transmission plan that maximizes total net benefits for all market participants. The findings suggest that RE subsidies can be effectively used to achieve system optimality when RE prices are fixed through bilateral contracts but have limited ability to achieve system optimality when RE prices are determined through locational marginal pricing. This limitation needs to be recognized in the design of RE subsidies.**

***Index Terms*—Game theory, generation interconnection, merchant transmission, Nash bargaining, renewable energy integration, renewable portfolio standard.**

NOMENCLATURE

Indices and sets:

n	Index for buses.
s	Index for scenarios.
t	Index for subperiods.
i	Index for generators.
j	Index for loads.
b	Index for supply or bid blocks.
k	Index for transmission lines.
g	Index for the RE generation unit of the RE generation company (RE-GenCo).
$o(k)$	Sending-end of transmission line k.
$r(k)$	Receiving-end of transmission line k.
$n(g)$	Planned bus location of the RE unit g.
Ω_N	Set of all system buses.
Ω_T	Set of all time subperiods.
Ω_S	Set of all scenarios.
Ω_n^G	Set of generators at Bus n.
Ω_n^L	Set of loads at Bus n.
Ω_i^b	Set of blocks for Generator i.
Ω_j^b	Set of blocks for Load j.
Ω^{TG}	Set of conventional generators.
Ω^{RG}	Set of RE generators.
Ω^{ET}	Set of existing transmission lines.
Ω^{CT}	Set of candidate transmission lines.
Ω^G	Set of all system generators.
Ω^L	Set of all system loads.

Parameters:

D_t	Duration of subperiod t.
λ_{ib}^G	Offer price of the bth block by the ith generator.
λ_{jb}^L	Bid price of the bth block by the jth load.
ICT_k	Annualized investment cost for transmission line k.
$\bar{P}_{ib}^G$	Size of the bth block for the ith generator.
$\bar{P}_{jb}^L$	Size of the bth block for the jth load.
$\bar{P}_{ibts}^G$	Size of the bth block for the ith RE generator at subperiod t in scenario s.
$\bar{F}_k$	Transmission capacity of line k.
X_k	Transmission reactance of line k.

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S_R RE subsidy per MWh of RE produced.

IC_{RG} Annualized RE generation investment cost.

d_{RG} Threat point of the RE-GenCo.

d_T Threat point of the TransCo.

FP RE contract price ($/MWh) for RE-GenCo.

M Arbitrary large constant used in the representation of an optimization constraint.

Decision variables:

P^G_{ibts} Power produced by the bth block of the ith generator at subperiod t in scenario s.

P^L_{jbts} Dispatched load for the bth block of the jth load at subperiod t in scenario s.

P^G_{its} Total dispatch (i.e., all cleared offer blocks) of the ith generator at subperiod t in scenario s.

Y_k Binary 0-1 decision variable for transmission line candidate k.

λ Negotiated payment rate ($/MWh) from the RE-GenCo to the TransCo.

F_{kts} Power flow of transmission line k at subperiod t in scenario s.

LMP_{nts} LMP of Bus n at subperiod t in scenario s.

δ_{nts} Voltage angle of Bus n at subperiod t in scenario s.

I. Introduction

MAJOR transmission projects are needed in the United States and other countries to integrate renewable energy (RE) resources into the power grid from remote areas. The delivery of RE is important for meeting Renewable Portfolio Standards (RPS). However, as of February 2009, nearly 300 000 MW of wind projects were waiting to be connected to the grid [1]. A key factor causing the backlog is the uncertainty concerning who should bear the transmission investment costs. This issue is to be resolved to encourage transmission investment to fulfill the RPS mandates.

The transmission expansion planning problem has been addressed by researchers from a technical perspective [2]–[7]. These studies focus primarily on optimal transmission investment decisions from centralized approaches, typically undertaken by centralized transmission planners or regulatory bodies. Usually, the plan is associated with a FERC-approved rate to recover the transmission investment. Various rate methods have been examined in the literature [8]–[11]. In addition to centralized planning approaches, decentralized market-based transmission planning approaches have also been explored [12]–[14].

Responsibility for the costs of transmission for reliability, economic, and operational performance purposes is typically assigned to load via a regulated rate. Generation developers usually bear the transmission cost for interconnecting their proposed generators. For example, currently RE generation companies (RE-GenCos) have to pay a large amount of interconnection costs to transmission owners prior to the service date. As a result, RE-GenCos bear the entire risk of both generation and transmission investments. This risk increases financing costs and discourages RE investment.

Merchant transmission projects provide RE-GenCos an alternative for connecting to the grid. In merchant transmission development, merchant transmission companies (TransCos) are responsible for financing and sponsoring the projects [15]. They recover investment costs by providing transmission services. The recovery, unlike that in traditional regulated transmission projects, is not guaranteed through an existing rate structure. Hence, it could be beneficial for TransCos to negotiate with RE-GenCos to share risks and to help with the recovery of investment costs.

From the perspective of an RE-GenCo, the preferred option might seem to be to build RE generation units and transmission lines itself because the centralized planning could result in maximum expected profits [7]. However in market environment, two issues could make the RE-GenCo choose instead to seek out a merchant TransCo partner: tremendous risks; and financing difficulties. Under the centralized planning option, the RE-GenCo would bear the entire risk arising from price volatility and renewable energy intermittency. Moreover, the required investment in both generation and transmission would require an extremely large amount of financing, and the inherent uncertainties and risks would make it difficult to obtain this financing. Under the partnership option, the RE-GenCo would be able to share risk and to limit its financial stake to generation investment only.

This study proposes a methodology for an RE-GenCo and a merchant TransCo to negotiate a contract for securing the transmission needed to integrate the RE-GenCo's renewable generation into a power grid. It is assumed that the RE-GenCo pays a transmission rate to the TransCo to help compensate the TransCo for its transmission investment costs. Attention is focused on the determination of an appropriate transmission rate, the formulation of a negotiation process capable of handling uncertainties, and conditions under which no negotiated settlement can be reached.

A Nash bargaining approach is employed to model the negotiation process. Nash bargaining is an important tool from cooperative game theory [16]. Unlike non-cooperative game theory (e.g., Nash equilibrium), Nash bargaining theory assumes that participants are able to bargain directly with each other to reach binding agreements. This assumption is appropriate for situations in which a small number of companies are bargaining over long-term investment decisions, because for such decisions it is natural for the companies to form a coalition and to select strategies beneficial to all.

Cooperative game theory has been used in studies of electric power systems to develop transmission cost allocation methods. In this literature, the most commonly used cooperative solution concepts include the core, the kernel, the nucleolus, and the Shapley value [17]–[23]. These solution concepts are designed for transferable utility games in which each player can transfer part of its utility payoff to other players. In particular, the total utility payoff achieved by the members of a coalition can be divided among these members by means of utility transfers. Gately considers a problem of dividing gains and costs from transmission investment among various areas in the Southern Electricity Region of India [17]. The solution concept of the core is applied and several possible distributions in the core are examined for which each area's propensity to disrupt is not too high. The core and the nucleolus are adopted in [18] to allocate fixed transmission costs to wheeling transactions. It is shown that many core outcomes exist; hence, the concept of a nucleolus outcome is introduced in order to obtain a unique solution by "minimizing the maximum regret". A congestion cost allocation method that combines the marginal cost concept of nodal pricing and the Aumann-Shapley mechanism is developed in [19] in order to obtain fair and economically efficient price signals for congestion management. As clarified in [20], the Shapley value assumes all orderings of players are equally likely and weights all players equally in order to obtain allocations that can be considered to be both fair and equitable.

The Nash bargaining solution is a cooperative game concept that assumes utility transfers (side payments) are not possible. For example, in the Nash bargaining study at hand it is assumed to be unrealistic for the bargaining parties to make side payments; rather, the only payments made are for energy, renewable credits and other commodities traded through the market. As a result of this restriction, the Nash bargaining solution can be less efficient than solutions for transferable utility games, in the sense that a smaller sum of surpluses is obtained by the parties.

The Nash bargaining solution does not attempt to maximize total utility; rather, it attempts to achieve a unique bargaining solution that is fair to each player in the following two senses. First, equally situated players are treated equally. Second, Pareto efficiency is achieved; that is, there are no other solutions (in the absence of side payments) that can make at least one party better off without lessening the utility of at least one other party. Nash bargaining is particularly tractable for two-player bargaining games and has many real-life applications, e.g., contract negotiation [24].

For the negotiation process under consideration in this study, both the RE-GenCo and the TransCo have to make decisions based on their forecasts of electricity prices and RE production, and these forecasts will affect the bargaining result [25]. However, this will not prevent a successful negotiation outcome as long as each company is satisfied with its own expected profits based on its own forecasts. For simplicity, it is assumed in this study that the two companies share their forecasting information and form common price and production forecasts.[1]

A prerequisite for a successful negotiation is a sufficient profit margin for each company. If the expected generation revenue is inadequate to cover the investment, an incentive might be required to ensure the investment is made. However, if an incentive is needed, policy makers will have to consider whether an incentive is warranted from a broader system viewpoint and, if so, what form it should take.[2] In this study, incentives in the form of RE subsidies are investigated and their effectiveness is assessed by comparing the results obtained from decentralized negotiation with RE subsidies to results obtained from a centralized transmission planning model with no RE subsidies.

A case study is used to demonstrate how Nash bargaining ensures a fair and Pareto-efficient utility allocation for the bargaining participants. Thus, it can be used as a viable way to encourage merchant transmission investment. The findings also provide guidelines to policymakers regarding the advantages and limitations of RE subsidies as a means to facilitate RE integration.

The remainder of the study is organized as follows. Sections II and III present the negotiation problem and apply Nash bargaining theory to this problem. In Section IV, a centralized transmission planning model is developed and used to evaluate RE subsidies. A six-bus case study is presented in Section V. Concluding remarks are given in Section VI.

II. Problem Formulation

A. Overview

This section describes the negotiation process between an RE-GenCo and a TransCo. It is assumed that the RE-GenCo has decided to invest in an RE generation unit g at a remote planned bus location $n(g)$. Transmission is needed to transport the RE output from $n(g)$ to a power grid, and the RE-GenCo has sought out a TransCo to undertake the needed transmission investment. The agreement with the TransCo includes a payment to be made by the RE-GenCo to the TransCo to cover the TransCo's investment costs. Determination of this payment, measured by a payment rate λ (\$/MWh), necessitates a negotiation between the two parties. The negotiation result will determine the investment of the not-yet-built RE generation unit and transmission lines.

To simplify the discussion, several assumptions are made. First, the terms of the agreement are expressed in annualized terms, i.e., for a typical year with annualized cost components. Second, maintenance costs are not explicitly modeled since they can be included as part of the annual capital investment (see the Appendix). Third, risk neutrality is assumed for the negotiation process, so that the expected utility (net benefit) levels attained by the RE-GenCo and the TransCo can be expressed in terms of expected profits without concern for profit variance. These simplifications can easily be relaxed.

B. Negotiation Process

Two possible outcomes from the negotiation are either an agreement is reached or both parties walk away. An agreement

[1]If this assumption is relaxed and the companies use their own forecasts, the model needs to incorporate the impact of forecasting accuracy on each company's utility function; see [16] for a treatment of a Nash bargaining problem in which this assumption is relaxed.

[2]Schumacher *et al.* [26] note that an incentive could be a policy initiative to promote transmission development. FERC also makes policies [27] for merchant transmission (MT) developers to hold auctions to attract and pre-subscribe some capacity to "anchor customers." The incentive can be a monetary incentive, such as renewable energy certificates (RECs) that need to be purchased by LSEs to meet the RPS [28], or energy subsidies such as investment tax credits (ITCs) and production tax credits (PTCs). Given these forms of monetary incentives, RE-GenCos could gain an additional revenue stream that facilitates the negotiation process.

is reached if the RE-GenCo can recover its generation investment costs and the TransCo can recover its transmission investment costs.

Two cases are considered for the energy price. In the first case, the energy price is assumed to be predetermined at a constant level FP (\$/MWh) because the RE-GenCo has previously signed power purchase agreements (PPAs) or other forms of bilateral contracts. This assumption is reasonable since, according to [29], various electric utilities have issued long-term PPAs with renewable energy developers. This common business practice could make it easier for RE-GenCos to finance RE projects. In the second case, the energy price is assumed to be determined by means of a market process.

Consider the first case. Let S_R (\$/MWh) denote the subsidy payment received by the RE-GenCo per MW of RE it produces, and let λ (\$/MWh) denote the negotiated rate (to be determined) that the RE-GenCo applies to its RE production level to determine its payment to the TransCo. Then the expected utility of the risk-neutral RE-GenCo, considering a set Ω_S of future possible power system scenarios s, and calculated over a set Ω_T of time subperiods (hours), is given by

$$U_{RG} = E_{s\in\Omega_S} \sum_{t\in\Omega_T} \sum_{b\in\Omega_g^b} D_t \left[\left[FP + S_R - \lambda - \lambda_{gb}^G\right] P_{gbts}^G\right] - \mathrm{IC}_{RG}. \quad (1)$$

In expression (1), P_{gbts} (MW) denotes the RE production level of the offered block b for the RE unit g during hour t in scenario s, The marginal RE production cost for block b in each hour h and each scenario s is assumed to be either commonly known or truthfully reported as the offer price λ_{gb}^G (\$/MWh).

Consider, instead, the second case. The expected utility (1) must now be modified to a market-based version U_{RG}^M that takes into account the market-based energy prices at $n(g)$, i.e., the locational marginal prices (LMPs) that would be determined at $n(g)$ should the transmission line connecting $n(g)$ to the power grid be constructed. This market-based version takes the form

$$U_{RG}^M = E_{s\in\Omega_S} \sum_{t\in\Omega_T} \sum_{b\in\Omega_g^b} D_t \left[\left[\mathrm{LMP}_{n(g)ts} + S_R - \lambda - \lambda_{gb}^G\right] P_{gbts}^G\right] - \mathrm{IC}_{RG}. \quad (2)$$

Note that the market-based energy prices can either be estimated by solving market-clearing problems or predicted using various forecasting methods [30].

For the TransCo, if an agreement is reached, its expected utility U_T is given by its expected profit, taking into account its receipt from the RE-GenCo and its transmission investment costs. This expected utility takes the following form:

$$U_T = E_{s\in\Omega_S} \sum_{t\in\Omega_T} D_t \left[\lambda P_{gts}^G\right] - \sum_{k\in\Omega^{\mathrm{CT}}} \mathrm{ICT}_k Y_k \quad (3)$$

where $P_{gts}^G = \sum_{b\in\Omega_g^b} P_{gbts}^G$ reflects the total RE power produced by all blocks b from the RE unit g.

If no agreement is reached, no investment will occur either in the RE generation unit or in the transmission line. In this case the expected utilities of the RE-GenCo and the TransCo are their threat point outcomes (d_{RG}, d_T), which hereafter are set equal to (0, 0) to reflect the assumption that both parties have zero cash positions prior to the negotiation.[3]

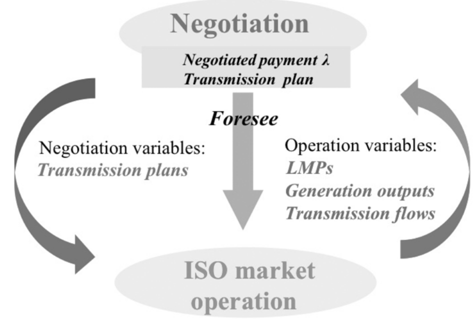

Fig. 1. Negotiation between the RE-GenCo and the TransCo.

The RE-GenCo and the TransCo are assumed to consider a set of possible transmission investment plans that includes no line, one line, or multiple lines connecting $n(g)$ to the power grid. With knowledge of their expected utility functions, their threat points, and anticipated market conditions, the RE-GenCo and the TransCo initiate a negotiation process to determine 1) a transmission investment plan and 2) an associated transmission payment rate λ. The negotiation can be based on projected revenue from the long term PPAs, or on the results (i.e., LMPs, generation dispatch levels, and transmission power flows) of an ISO market operation as depicted in Fig. 1.

Note that the negotiated rate is only settled after the RE generation unit and transmission line go live for operation. In order to avoid any unnecessary agreement default or untrue information report, settlement approaches could be designed carefully by the two companies, such as how to monitor and track the RE production, or how an ISO might oversee the execution of the final settlement.

C. Policy Implications for RE Subsidies

Traditionally, policymakers promoted transmission plans for the benefit of all system participants. In today's market-based environment, however, policymakers do not have full control of transmission plan development. Nevertheless, policymakers can use incentives or subsidies in an attempt to steer a negotiated merchant transmission plan towards a preferred plan.

Specifically, the RE subsidy payment S_R enters into the determination of expected utility for both the RE-GenCo and the TransCo. Thus, policymakers could adjust S_R in an attempt to encourage the RE-GenCo and TransCo to agree on a transmission plan that benefits all system participants and not just themselves. In Section IV this study will explore the possibility of using S_R to ensure such a system-optimal transmission investment plan.

[3]As will be seen in Section III, the outcome for the Nash bargaining negotiation process for the RE-GenCo and TransCo is not affected by this threat-point assumption. Any non-zero initial cash positions held by the RE-GenCo and the TransCo would have to be added both to their expected utility functions and to their threat points. These cash positions would then cancel out in the formulation of the objective function for the Nash Bargaining problem.

III. Negotiation: A Nash Bargaining Approach

This section models the negotiation process between the RE-GenCo and the TransCo as a two-player Nash bargaining problem using both analytical and numerical formulations.

A. Nash Bargaining

Research on two-player bargaining problems was initiated by John Nash [31], [32]. Nash assumed that two players are in a negotiation to determine an outcome from among a compact convex set of possible (expected) utility outcomes in R^2, referred to as the *utility possibility set* U. If the players fail to agree on a settlement point $u = (u_1, u_2)$ in U, they obtain a default "no settlement" outcome $d = (d_1, d_2)$ in U, referred to as the players' *threat point*. The *barter set* $B(U, d)$ is the set of all u in U satisfying $u \geq d$.

Let D denote the collection of all bargaining problems (U, d). Nash proved that there exists a unique function $f : D \rightarrow R^2$ mapping each bargaining problem (U, d) into a solution $f(U, d) = (f_1(U, d), f_2(U, d))$ in $B(U, d)$ that satisfies the following four axioms.

- *Axiom 1:* Invariance under Positive Linear-Affine Transformation. For any real-valued monotonic linear-affine function H defined over U, $f(H(U), H(d)) = H(f(U, d))$.
- *Axiom 2:* Symmetry. If $d_1 = d_2$, and if $(u_1, u_2) \in U$ if and only if $(u_2, u_1) \in U$, then $f_1(U, d) = f_2(U, d)$, implying that the solution should provide equal gains from cooperation.
- *Axiom 3:* Independence of Irrelevant Alternatives. Given (U, d) and (U', d) with $U \subset U'$, if $f(U', d) \in U$, then $f(U, d) = f(U', d)$, implying that the solution $f(U, d)$ in U is not affected by the presence of the "irrelevant" alternatives in the complement set U′/U.
- *Axiom 4:* Pareto Efficiency. If u and u' are elements of U for a given (U, d), and $u' > u$, then $f(U, d) \neq u$, implying Pareto-efficiency of the solution.

Nash constructively demonstrated that his unique bargaining function $f(U, d)$ can be obtained as follows:

$$f(U, d) = \arg \underset{\substack{(u_1, u_2) > (d_1, d_2) \\ (u_1, u_2) \in U}}{\text{maximize}} \quad (u_1 - d_1)(u_2 - d_2). \tag{4}$$

The objective function in (4) is now referred to as the *Nash product (NP)* of the (expected) utility outcomes for the two players. The solution to (4) is referred to as a *Nash bargaining solution (NBS)*, an important solution concept in cooperative game theory due to its simple, intuitively appealing form and the fairness and efficiency properties assured by Axioms 1–4.

Specifically, the fairness and efficiency properties of Axioms 1–4 can be explained as follows. The first axiom asserts that the bargaining method should not result in an outcome that depends on the precise "units" that the players use to represent their preference orders over outcomes. A player's preference order over outcomes is unaffected by a monotonic linear-affine transformation of his (expected) utility function, hence the bargaining outcome should also be invariant to such a transformation.

Axiom 2 asserts that players with equal threat points who have an equal opportunity to achieve utility outcomes (i.e., their utility possibility set is symmetric) should achieve the same utility outcome under the bargaining method. That is, the bargaining method should not advantage either player relative to the other under these conditions, since the two players are essentially identical.

The third axiom states that irrelevant alternatives should not have any impact on the bargaining result. For example, if two options $\{\mathrm{T1}, \mathrm{T2}\}$ are under consideration, and both players prefer T2 to T1, then adding a third option T3 that is "irrelevant" (not preferred to either T1 or T2) should not change their preferences between T1 and T2. This also holds for the removal of an irrelevant alternative. If the two players choose T2 among three options $\{\mathrm{T1}, \mathrm{T2}, \mathrm{T3}\}$, then they should still choose T2 if the "irrelevant" option T3 is removed from consideration.

The fourth axiom ensures the efficiency of the bargaining method, in the sense that "utility" is not wasted. The bargaining method guarantees that bargaining will not cease while there is still a feasible way to increase the utility of one player without hurting the utility of the other player.

The NB formulation can easily be extended to n-person bargaining games with substantially weaker requirements on sets and functional forms. For example, compactness and convexity of the utility possibility sets U in R^2 is not needed to ensure the existence of a unique NB solution function $f : D \rightarrow R^2$ that satisfies Axioms 1–4. Rather, as established in [26], it suffices that each derived Barter Set $B(U, d)$ in R^2 is "corner concave," meaning (roughly) that it has a closed, bounded, and concave Pareto-efficient frontier. Empirical evidence in support of NB theory has been obtained from human-subject bargaining experiments [35].

B. Bargaining on RE Interconnection: A Simple Illustrative Analytical Model

A relatively simple analytical model is used in this section to provide basic intuitive insights regarding the negotiation process. Parameters and functional forms are represented in per-hour units; the extension to longer periods of time is straightforward. Also, the consideration of transmission constraints is deferred until later sections.

Suppose the pro-rated hourly construction cost for an RE generation unit in a remote area is C_0 ($/MWh). The maximum available power output of the RE unit is denoted by r (MW). To recognize the variability of this RE resource, r is modeled as a random variable with probability density function (pdf) $g(r)$ and cumulative density function (cdf) $G(r)$. The model also assumes a constant RE marginal production cost C_R ($/MWh) and a constant RE subsidy S_R ($/MWh).

The RE-GenCo seeks out a merchant TransCo to invest in one or more transmission lines to deliver its RE output P_R (MW) to distant load centers. The pro-rated hourly transmission investment cost is represented by C_T ($/MWh). The sales price for RE is represented by a fixed payment D_R ($/MWh), interpreted to be the RE strike price that the RE-GenCo has assured for itself through some previously contracted PPA. The two parties enter into a negotiation in an attempt to reach an agreement on a payment rate λ ($/MWh) and a transmission capacity F_T (MW).

Note that the RE output P_R is limited by the lower of the maximum available output r and the transmission capacity F_T:

$$P_R = \min\{r, F_T\}. \tag{5}$$

Using these representations, if an agreement is reached, the RE-GenCo's expected utility is its expected profit

$$u_R = EP_R[D_R + S_R - C_R - \lambda] - C_0 \tag{6}$$

and the TransCo's expected utility is given as

$$u_T = EP_R\lambda - F_T C_T. \tag{7}$$

If no agreement is reached, the outcome is the threat point for the RE-GenCo and TransCo, assumed to be given by (0, 0). Extension to an intertemporal optimization problem is taken up in Section III-C, below.

The RE-GenCo and TransCo are assumed to use a Nash bargaining process for their negotiation. Specifically, it is assumed they have agreed to try to determine solutions for the decision variables λ and F_T by solving the following Nash bargaining problem:

$$\max_{\lambda, F_T} NP = u_R(\lambda, F_T) \cdot u_T(\lambda, F_T) \tag{8}$$

subject to $u_R \geq 0$ and $u_T \geq 0$.

Assuming a solution exists for (8) with non-binding inequality constraints (i.e., a solution satisfying $u_R > 0$ and $u_T > 0$), the initial solution step is to take the first order derivatives of *NP* with respect to λ and F_T

$$\frac{\partial NP}{\partial \lambda} = \frac{\partial u_R}{\partial \lambda} u_T + \frac{\partial u_T}{\partial \lambda} u_R \tag{9}$$

$$\frac{\partial NP}{\partial F_T} = \frac{\partial u_R}{\partial F_T} u_T + \frac{\partial u_T}{\partial F_T} u_R. \tag{10}$$

Using (5), $EP_R = E_r \min(r, F_T)$ and when $r > F_T, \min\{r, F_T\} = F_T$; and when $r \leq F_T, \min\{r, F_T\} = r$. Using integration by parts, the expected RE output can thus be written as

$$\begin{aligned} EP_R &= F_T \cdot Pr(r > F_T) + Er|_{r \leq F_T} \\ &= F_T - \int_0^{F_T} G(r) dr. \end{aligned} \tag{11}$$

From (11), the partial derivative of EP_R with respect to F_T can be expressed as

$$\frac{\partial EP_R}{\partial F_T} = 1 - G(F_T). \tag{12}$$

The partial derivative of u_R and u_T with respect to λ and F_T can then be obtained as

$$\partial u_R / \partial \lambda = -EP_R \tag{13}$$

$$\partial u_R / \partial F_T = [1 - G(F_T)] \times [D_R + S_R - C_R - \lambda] \tag{14}$$

$$\partial u_T / \partial \lambda = EP_R \tag{15}$$

$$\partial u_T / \partial F_T = [1 - G(F_T)] \times \lambda - C_T. \tag{16}$$

Inserting (13) and (15) into (9) and setting it to zero, which is a first-order necessary condition for (8) to have an interior solution, the following condition can be derived:

$$EP_R[u_R - u_T] = 0. \tag{17}$$

Since the expected RE output EP_R is normally positive, (17) will typically only be satisfied when

$$u_R = u_T. \tag{18}$$

This is a logical outcome, implying that the participants' are equalized if an agreement is reached.

Inserting (14), (16) and (18) into (10) and setting it to zero, which is another first order necessary condition for (8) to have an interior solution, it is found that

$$[[1 - G(F_T)][D_R + S_R - C_R] - C_T] u_T = 0. \tag{19}$$

Since $u_T > 0$ is assumed for this interior solution, the resulting transmission capacity F_T can be solved for as follows:

$$F_T = G^{-1}\left(1 - \frac{C_T}{D_R + S_R - C_R}\right). \tag{20}$$

Substituting (6) and (7) into (18), the solution for λ is found to be

$$\lambda = \frac{D_R + S_R - C_R}{2} - \frac{C_0 - F_T C_T}{2EP_R}. \tag{21}$$

As seen above, the negotiated payment rate λ and investment transmission capacity F_T can be explicitly characterized for this model under RE output uncertainty, assuming an interior solution to (8) exists. Inserting (20) and (21) into the expected utility expressions (6) and (7), the following explicit expression is obtained for (18):

$$u_R = u_T = [EP_R[D_R + S_R - C_R] - C_0 - F_T C_T]/2. \tag{22}$$

Given F_T, the associated transmission plan can be determined. Since the transmission investment is lumpy in nature, the transmission plan is likely to consist of a set of discrete transmission candidates. The selection of certain particular transmission candidates from this set will be discussed in the following subsection.

C. Bargaining on RE Interconnection: Detailed Formulation

Consider, now, a fuller modeling of this bargaining process that takes transmission and generation constraints into consideration. As before, an RE-GenCo and a TransCo are interested in negotiating an agreement under which the TransCo builds one or more transmission lines to connect the RE-GenCo's unit to the power grid. However, this bargaining process now takes place within a power system with multiple conventional and RE generators and with conventional energy prices determined through an ISO-managed optimal power flow optimization.

As shown in Fig. 1, the bargaining process is formulated as a two-level intertemporal optimization problem with investment costs expressed on an annualized rather than hourly basis. The upper-level problem consists of a Nash bargaining problem between the RE-GenCo and TransCo conditional on a collection of lower-level problems, one for each hour t and each scenario s, where s reflects RE uncertainties such as variable wind speed. Each lower-level problem represents the operations of an ISO-managed market (for a particular hour t in a particular scenario s) using a standard DC optimal power flow formulation to derive LMPs, generation dispatch levels, and transmission line power flows.

The detailed formulation for this two-level optimization problem is presented below, where the RE-GenCo's expected utility U_{RG} and the TransCo's expected utility U_T across possible scenarios s in Ω_S and hours t in Ω_T are given by (2) and (3):

$$\max_{\lambda, Y_k} U_{RG} \cdot U_T \tag{23}$$

subject to

$$U_{RG} \geq 0 \tag{24}$$
$$U_T \geq 0 \tag{25}$$
$$-M \sum_{k \in \Omega^{\mathrm{CT}}} Y_k \leq \lambda \leq M \sum_{k \in \Omega^{\mathrm{CT}}} Y_k \tag{26}$$

where

$$\begin{aligned} P^G_{gbts}, &\forall t \in \Omega_T, \forall s \in \Omega_S \\ &= \underset{P^G_{ibts} P^L_{jbts}}{\operatorname{argmax}} \sum_{j \in \Omega^L_n} \sum_{b \in \Omega^b_j} \lambda^L_{jb} P^L_{jbts} \\ &\quad - \sum_{i \in \Omega^G} \sum_{b \in \Omega^b_i} \lambda^G_{ib} P^G_{ibts} \end{aligned} \tag{27}$$

subject to

$$\begin{aligned} &\sum_{j \in \Omega^L_n} \sum_{b \in \Omega^b_j} P^L_{jbts} + \sum_{k \,|\, o(k)=n} F_{kts} - \sum_{k \,|\, r(k)=n} F_{kts} \\ &\quad - \sum_{i \in \Omega^G_n} \sum_{b \in \Omega^b_i} P^G_{ibts} = 0, (\mathrm{LMP}_{nts}), \quad \forall n \in \Omega_N \end{aligned} \tag{28}$$

$$0 \leq P^G_{ibts} \leq \bar{P}^G_{ib}, \ \forall i \in \Omega^{TG}, \ \forall b \in \Omega^b_i \tag{29}$$
$$0 \leq P^G_{ibts} \leq \bar{P}^G_{ibts}, \ \forall i \in \Omega^{RG}, \ \forall b \in \Omega^b_i \tag{30}$$
$$F_{kts} = \frac{1}{X_k} \left[\delta_{o(k)ts} - \delta_{r(k)ts}\right], \ \forall k \in \Omega^{\mathrm{ET}} \tag{31}$$
$$-\bar{F}_k \leq F_{kts} \leq \bar{F}_k, \ \forall k \in \Omega^{\mathrm{ET}} \tag{32}$$
$$\begin{aligned} &-(1 - Y_k)M \leq F_{kts} - \frac{1}{X_k}\left[\delta_{o(k)ts} - \delta_{r(k)ts}\right] \\ &\quad \leq (1 - Y_k)M, \ \forall k \in \Omega^{\mathrm{CT}} \end{aligned} \tag{33}$$
$$-Y_k \bar{F}_k \leq F_{kts} \leq Y_k \bar{F}_k, \ \forall k \in \Omega^{\mathrm{CT}}. \tag{34}$$

The upper level problem, consisting of (23)–(26), reflects the requirements of the Nash bargaining problem. Inequality (26) (with an arbitrarily large constant M) ensures a zero payment rate λ if no transmission line investment is made and an essentially unrestricted range for the payment rate if it is made.

Each lower-level problem consists of (27)–(34) for a particular hour t and scenario s. The objective (27) of this lower-level problem is to maximize total net surplus from market operations. Constraints (28) enforce real power balance at each bus n; the associated shadow price for each bus n then determines the LMP for bus n. Constraints (29) and (30) impose generation capacity limits on conventional and RE generating units, respectively. Note that the maximum generation capacity $\bar{P}^G_{ibts}$ for each RE unit i varies in hours and scenarios, allowing for the variability of the RE resource. Constraints (31) and (32), (31) enforce transmission line limits for existing transmission lines. Constraints (33) and (34) enforce transmission line limits for any candidate transmission lines that are to be built. When line k is selected for construction ($Y_k = 1$), the transmission limit for line k is enforced. When line k is not selected for construction ($Y_k = 0$), the two constraints are essentially removed (or inactive).

This formulation can be modified to consider market-based RE prices (LMPs). If the RE-GenCo has no PPAs or other bilateral contracts, its expected utility function in (23) can be replaced by U^M_{RG} given in (2). In addition to the RE production P_{gbts}, the RE-GenCo's expected utility U^M_{RG} now is also determined by another model variable—the RE market price $\mathrm{LMP}_{n(g)ts}$, which is the shadow price of constraint (28) and solved in the lower-level ISO market operation problem. The LMPs depends on the electricity supply and demand, and also on the system network topology, which in turn is affected by the transmission investment agreement between the RE-GenCo and the TransCo with which it is negotiating.

Note that the above formulation is focused only on transmission investment. In reality, however, generation and transmission investments are closely related and should be considered as two inseparable components in the bargaining process. Joint decision-making for merchant generation and transmission investment is discussed in the Appendix.

IV. Implications for Renewable Subsidy Policy

In this section a centralized transmission planning model is developed as a benchmark for comparison. The planning objective is to maximize the net benefit for all power system participants, including LSEs that are not participants in the negotiation between the RE-GenCo and TransCo. The purpose is to determine if the negotiated solution outlined in Section III can be steered towards the system-optimal solution via an RE subsidy.

A. Centralized Planning and Policy Implications

In a traditional integrated resource planning process, a centralized planner would determine a transmission plan to deliver the output of an RE unit. Let B_R (\$/MWh) be the per-MWh benefit from RE. Similar to Section III-B, the model built below represents a slice-in-time snapshot of system operations, e.g., for a peak-load hour. It can be extended to longer time periods with time varying B_R.

The centralized planner needs to determine the necessary transmission capacity F_T to maximize the expected system net benefits SS:

$$\underset{F_T}{\text{maximize}} \quad SS = EP_R B_R - EP_R C_R - F_T C_T \tag{35}$$

where the notation in (35) is the same as used in Section III-B. Taking the derivative of SS with respect to F_T, and setting it equal to 0, gives

$$0 = [1 - G(F_T)][B_R - C_R] - C_T. \tag{36}$$

F_T can then be solved for explicitly as follows:

$$F_T = G^{-1}\left(1 - \frac{C_T}{B_R - C_R}\right). \tag{37}$$

Comparing the negotiated solution (20) with the centralized solution (37), it is conceivable that the RE subsidy payment S_R in (20) can be adjusted to steer the negotiated solution towards the optimal solution. In particular, equating (20) and (37), we obtain

$$S_R = B_R - D_R. \tag{38}$$

Equation (38) indicates that the optimal RE subsidy payment should be set equal to the difference between the benefit from consuming RE and the payment for purchasing it.

Certainly, determining the benefit B_R is not a trivial task. In a market environment, it could be simply modeled as bid prices or the willingness to pay for renewable energy. In a broader sense, it could also include environmental benefits and other non-monetary benefits. Also, in practice, the impact of system operation conditions such as transmission flows and market prices should be considered (see Section IV-B).

Nevertheless, this closed-form result could be used as a rule of thumb for policymakers to design RE subsidies, and to establish a subsidy mechanism that provides merchant investors with sufficient market incentives for achieving optimal transmission investment plans.

B. Centralized Planning: A Detailed Formulation

A more detailed formulation of the centralized planning model with uncertainties and realistic constraints is presented in the following:

$$\begin{aligned} \underset{P^G_{ibts}, P^L_{jbts}, Y_k}{\text{maximize}} \quad & E_{s\in\Omega_S} \sum_{t\in\Omega_T} D_t \left[\sum_{j\in\Omega^L} \sum_{b\in\Omega^b_j} \lambda^L_{jb} P^L_{jbts} \right. \\ & \left. - \sum_{i\in\Omega_G} \sum_{b\in\Omega^b_i} \lambda^G_{ib} P^G_{ibts} \right] - \sum_{k\in\Omega^{\mathrm{CT}}} \mathrm{ICT}_k Y_k \end{aligned} \tag{39}$$

subject to $\forall t \in \Omega_T$, $\forall s \in \Omega_S$, constraints (28)–(34).

The objective is to maximize expected system net benefits SS consisting of operational net earnings net of the transmission investment cost. The operational constraints are identical with (28)–(34) appearing in the negotiation model.

V. Numerical Results

A. Six-Bus Test Case

This subsection provides a detailed formulation for the negotiation of an RE interconnection using a six-bus test case developed by Garver [36]. As seen in Fig. 2, this test case comprises five existing buses $\{\mathrm{B1}, \ldots, \mathrm{B5}\}$, six existing transmission lines (solid black), five loads $\{\mathrm{L1}, \ldots, \mathrm{L5}\}$, two conventional generators $\{\mathrm{G1}, \mathrm{G2}\}$, and one RE-GenCo located at a potential Bus 6. The RE-GenCo is assumed to have a single wind generation unit (WG3). In order to deliver the RE-GenCo's wind power to the grid, one or more transmission lines need to be constructed (dotted blue lines).

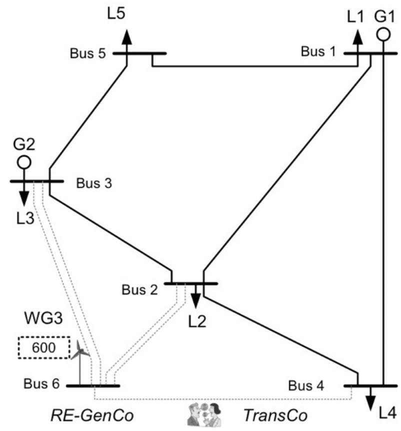

Fig. 2. Garver's six-bus test case.

TABLE I
CONVENTIONAL GENERATOR AND LOAD DATA

Conventional Generators				Loads		
Bus	G	Off. Size (MW)	Off. Price ($/MWh)	L	Bid Size (MW)	Bid Price ($/MWh)
1	G1	[200;100; 100]	[21;23; 28]	L1	[40;40]	[43;30]
2				L2	[80;80;80]	[54;50;48]
3	G2	[210;210; 140]	[30;34; 43]	L3	[20;20]	[30;26]
4				L4	[80;80]	[45;32]
5				L5	[80;80;80]	[50;42;30]

The supply offer and demand bid data for the two conventional generators and the five loads are given in Table I in block form. For example, G1's supply offer consists of three quantity blocks 200 (MW), 100 (MW), and 100 (MW), with corresponding block prices given by \$21/MWh, \$23/MWh, and \$28/MWh.

Table II provides the RE-GenCo's cost and operational data. The third column gives the RE-GenCo's generation investment cost IC_{RG} (\$). The fourth column gives the RE-GenCo's marginal production cost (\$/MWh), assumed to be constant. The fifth column gives P_{rate} (MW), the nameplate capacity of the RE-GenCo's wind unit WG3. As in [5], the maximum possible output $P_{\max}$ of this wind unit is determined as a non-linear function of wind speed v and P_{rate} conditional on three parameters: cut-in, cut-out, and rated wind speed V_{ci} (m/s), V_{co} (m/s) and V_{rate} (m/s). This function is given by

$$P_{\max} = \begin{cases} 0 & 0 \le v < v_{\mathrm{ci}} \\ P_{\mathrm{rate}}(v - V_{\mathrm{ci}})/(V_{\mathrm{rate}} - V_{\mathrm{ci}}) & V_{\mathrm{ci}} \le v < V_{\mathrm{rate}} \\ P_{\mathrm{rate}} & V_{\mathrm{rate}} \le v \le V_{co} \\ 0 & V_co < v. \end{cases} \tag{40}$$

In actual transmission planning, a set of feasible transmission line candidates is typically screened based on reliability studies

TABLE II
WIND UNIT DATA

Bus	Name	Invest. Cost (10^6\$)	Prod. Cost	P_{rate}	V_{ci}	V_{rate}	V_{co}
6	WG3	10	2	600	4	10	22

TABLE III
TRANSMISSION LINE DATA

Name	From Bus	To Bus	Reactance (Ω)	Limit (MW)	Cost (\$$10^6$)	Type
T1	1	2	0.4	250	-	E
T2	1	4	0.6	220	-	E
T3	1	5	0.2	300	-	E
T4	2	3	0.2	300	-	E
T5	3	5	0.2	300	-	E
T6	2	6	0.3	150	8.0	C
T7	2	6	0.15	300	13	C
T8	3	6	0.4	150	9.2	C
T9	3	6	0.3	200	10	C
T10	4	6	0.3	200	11	C

TABLE IV
SEASONAL WIND SPEEDS (M/S) FOR THREE WIND SPEED SCENARIOS

Scenario	Spring	Summer	Fall	Winter
S1=High wind	7	5	10	9
S2=Medium wind	5	5	8	9
S3=Low wind	2	1	5	8

[29]. Table III presents the data for five existing (T1–T5) denoted as type E and five candidate (T6–T10) transmission lines denoted as type C. Each of the five candidate lines connects Bus 6 to the grid. The investment cost is calculated as the product of the line capacity and the per-unit cost at a given voltage level, tower construction and conductor configuration [30]. The data given in Table III are a function of the line capacity for each transmission line. The pattern of transmission costs also reflects economies of scale, e.g., building one 300-MW line between Buses 2 and 6 is less expensive than building two 150-MW lines connecting these buses.

To accommodate the variability of the wind unit WG3, three wind speed scenarios are constructed for four subperiods in a year, which are represented by four seasons with equal time duration, i.e., $1/4 \cdot 8760\ \mathrm{h} = 2190\ \mathrm{h}$. The seasonal wind speeds (m/s) that characterize each scenario are given in Table IV. For each wind speed scenario, the maximum possible output of the wind unit in each season is calculated using (40). Note that the wind unit can normally generate more RE during the Fall and Winter due to ample wind resources.

B. Negotiated Solution With Fixed RE Price FP

Consider the high-wind scenario S1 in Table IV under the assumption that the RE-GenCo has signed a PPA that fixes the price of its RE at the constant level $FP = \$12$/MWh. The case in which the RE price is instead determined through a market process is discussed below in Section V-C.

Suppose that no subsidies are available for wind energy, i.e., $S_R = 0$. The RE-GenCo and the TransCo now get together to negotiate how to invest in transmission. However, after engaging in Nash bargaining over the set of feasible transmission plans consisting of all possible combinations of the transmission lines listed in Table III [i.e., solving the Nash bargaining problem (23)–(34) for these plans], it is determined that none of these plans ensures each company a nonnegative expected utility gain, i.e., an expected utility level at least as great as their threat point. The negotiation thus breaks down and no transmission lines are built.

TABLE V
FP-BASED NEGOTIATED OUTCOMES FOR THE HIGH WIND SPEED SCENARIO WITH $S_R = 0$ AND VARYING FP LEVELS

FP (*\$/MWh*)	Line Investment	λ (*\$/MWh*)	U_T (*10^6\$*)	U_{RG} (*10^6\$*)
12	None	0	0	0
17	T7	8.434	0.545	0.545
22	T6,T7	12.644	5.300	5.300
27	T6,T7	15.144	10.506	10.506

TABLE VI
FP-BASED NEGOTIATED OUTCOMES FOR THE HIGH WIND SPEED SCENARIO WITH $FP = \$12$/MWH AND VARYING S_R LEVELS

S_R (*\$/MWh*)	Line Investment	λ (*\$/MWh*)	U_T (*10^6\$*)	U_{RG} (*10^6\$*)
5	T7	8.434	0.545	0.545
10	T6, T7	12.644	5.300	5.300
15	T6, T7	15.144	10.506	10.506

An alternative way to try to achieve an agreement in this no-subsidy circumstance is for the RE-GenCo to sign a long-term PPA with a higher strike price FP prior to initiating the Nash bargaining process. Table V reports outcomes for a series of Nash bargaining games with successively increased FP levels, starting with $FP = \$12$/MWh.

Specifically, it is seen in Table V that the RE-GenCo and the TransCo are successfully able to negotiate more transmission line investment as FP increases, with accompanying increases in the transmission payment rate λ and their expected utility gains. Note, in particular, that the RE-GenCo and the TransCo achieve equal expected utility gains for each tested FP level. This utility outcome is consistent with (18), established for the analytical model, and illustrates the fairness and efficiency of the Nash bargaining solution.

If the PPA contract price FP is fixed at \$12/MWh, another way to encourage the two companies to come to an agreement on a transmission plan is through an appropriate RE subsidy S_R approved by policymakers. To explore how the S_R level affects the negotiation, experiments were conducted with an initial subsidy of $S_R = \$5$/MWh that was then successively increased in increments of \$5/MWh. The resulting negotiated transmission plan, payment rate, and expected utility gains are reported in Table VI.

Observe that, when $S_R = \$5$/MWh and $FP = \$12$/MWh, the selected transmission plan is T7. In the resulting settlement the RE-GenCo agrees to pay the TransCo $\lambda = \$8.43$/MWh for recovering the cost of the transmission investment for the candidate line T7, and the expected utility gain for each company is \$545 000. These negotiated results are exactly the same as the

TABLE VII
LMP-BASED NEGOTIATED OUTCOMES FOR THE HIGH WIND SPEED SCENARIO WITH NO RE SUBSIDY

S_R (\$/MWh)	Line Investment	λ (\$/MWh)	U_T (10^6\$)	U_{RG} (10^6\$)
0	T6,T7,T9	16.4	6.072	6.072

results reported in Table V for $FP = \$17$/MWh. This phenomenon is observed across the two tables. This indicates that an increase in the subsidy payment $\mathrm{S_R}$ can substitute for an increase in the FP. This substitutability is clarified by an examination of (1), where it is seen that FP and S_R play similar roles in determining the expected utility levels of the two companies.

Tables V and VI also show that a small \$5/MWh increase in FP or S_R can result in up to a \$5 000 000 increase in the expected utility gains for the two companies. Thus, even a small price incentive can play a very important role in encouraging RE transmission investment. Finally, Table VI shows that higher RE subsidies result in more transmission lines being constructed. A more detailed sensitivity analysis expanding upon these results is presented below in Section V-E.

C. Negotiated Solution With Market-Based LMPs

The previous section explores the *FP-based case* in which the RE-GenCo (wind producer) at Bus 6 enters into a PPA to ensure in advance a fixed wind-power price FP. However, some US ISO-managed energy regions (e.g., MISO) now permit wind producers to offer their wind power into a day-ahead market and receive LMP payments in a market settlement.

It is therefore of interest to investigate in this section the *LMP-based case* in which market-based LMPs for both wind power and conventional generation are determined through the centralized market process represented by (27)–(34). The RE-GenCo then uses the market-based expected utility function U_{RG}^M in (2) in its negotiation with the TransCo for determination of a transmission plan.

In particular, consider the high wind speed scenario S1 in Table IV for the LMP-based case under the assumption that no RE subsidy is available. Table VII displays the negotiated outcomes that result for the RE-GenCo and the TransCo from an application of the Nash bargaining process (23)–(34) with LMPs for both wind power and conventional generation determined in the lower-level problem through a market process.

Surprisingly, Table VII shows that the two companies are able to reach an agreement under this LMP-based negotiation even without an RE subsidy. The negotiated outcome is a transmission plan that calls for the construction of three new lines: namely, two new lines T6 and T7 to connect Bus 2 to the wind-unit Bus 6, and one new line T9 to connect the wind-unit Bus 6 to Bus 3. Under this plan each company attains the same expected utility gain, \$6 072 000. This again demonstrates the fairness and Pareto-efficiency of the Nash bargaining approach.

It is interesting to compare the differences in outcomes between the FP-based case in which the price of wind-power is set in advance at a contracted price FP and the LMP-based case in which the price of wind power is determined through a centralized LMP-based market process. Fig. 3 reports seasonal

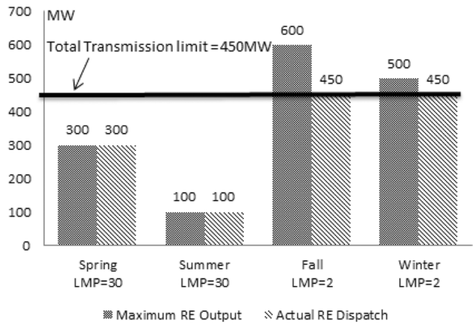

Fig. 3. FP-based case: Bus 6 LMPs and wind dispatch levels by season for the high wind speed scenario with $FP = \$12$/MWh and $S_R = \$15$/MWh (implemented negotiated transmission plan: T6 and T7).

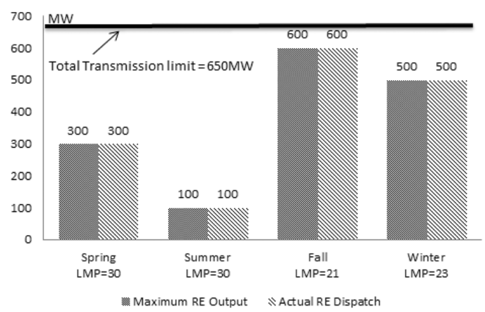

Fig. 4. LMP-based case: Bus 6 LMPs and wind dispatch levels by season for the high wind speed scenario with $S_R = 0$ (implemented negotiated transmission plan: T6, T7, and T9).

outcomes for the FP-based negotiation, and Fig. 4 reports seasonal outcomes for the LMP-based negotiation. In both figures, the maximum RE (wind) outputs are computed based on the seasonal wind speeds for the high wind speed scenario S1 in Table IV.

As seen in Figs. 3 and 4, the Bus 6 LMPs and wind dispatch outcomes for the two cases do not differ substantially for the Spring and Summer seasons. In these seasons the wind unit, unconstrained by transmission limits, produces power at its maximum possible levels (300 MW and 100 MW). Consequently, for both the FP-based and LMP-based cases, the wind unit is dispatched as an infra-marginal unit, and the LMP at Bus 6 is determined by marginal generation units (e.g., \$30/MWh by G2).

On the other hand, outcomes do differ substantially for the Fall and Winter seasons. For the FP-based case, the wind unit is constrained by transmission limits and so cannot produce to its full capacity. Consequently, the wind unit is a marginal unit whose marginal cost (\$2/MWh) determines the LMP at its own Bus 6. In contrast, for the LMP-based case, due to "overinvestment" in the three lines T6, T7, and T9, the wind unit is not constrained by transmission limits and hence is dispatched at maximum capacity. The LMP at Bus 6 is therefore determined by the marginal cost of G1, a marginal generator that has a much higher marginal cost than the wind unit.

More generally, for all three wind-speed scenarios given in Table IV, the LMP-based case with $\mathrm{S_R} = 0$ results in a Nash bargaining solution in which the RE-GenCo and the TransCo agree to construct three new transmission lines: T6, T7, and T9. By investing in these three new lines, it is guaranteed that the

TABLE VIII
SYSTEM-OPTIMAL TRANSMISSION PLAN Y_C

Candidate	Y_6	Y_7	Y_8	Y_9	Y_{10}
Decision	1	1	0	0	0

wind unit's generation will never be constrained by transmission limits and hence will always be dispatched at its maximum output level. In consequence, the wind unit will never be marginal and hence will never set the LMP at any bus. In particular, the LMP at the RE-GenCo's Bus 6 will be set by the marginal cost of more expensive conventional marginal generation. As a result, the RE-GenCo will have a much higher expected utility (profit) level than if the LMP at Bus 6 was set at its own low marginal cost. This high expected utility gain makes it worthwhile for the RE-GenCo to build the three new transmission lines.

D. Centralized Transmission Planning

For the simple analytical modeling of centralized transmission planning presented in Section IV-A, it was shown that the RE subsidy S_R can be set to ensure that the negotiated transmission plan solution coincides with the system-optimal centralized solution. This section examines the possibility of adjusting the RE subsidy to achieve this goal for the more comprehensive formulation (39) of a centralized transmission planning problem presented in Section IV-B.

The system-optimal transmission plan (Y_C) that solves the centralized optimization problem (39) is represented in Table VIII by indicating the inclusion (or not) of a line k in the plan by a designation of a 1 (or 0) value for a corresponding indicator function Y_k. As shown, the system-optimal plan is to invest in the two candidate lines T6 and T7 in order to maximize expected system net benefits (SS).

The system-optimal plan Y_C is independent of any subsidy policy; the central planner directly selects an optimal transmission plan to maximize SS, and this selection then results in a particular distribution of gains across market participants. By construction, then, no other planning approach can achieve higher SS than centralized planning. Therefore, centralized planning is suggested as the most efficient approach when the renewable generation and transmission companies are under regulation and there is a reasonable level of certainty regarding both prices and renewable energy output. For example, this situation may occur when production subsidies are already set and relatively stable, and renewable energy producers have priority in energy dispatch and need not compete with other power producers.

In general, however, centralized planning is not practical due to its high information requirements in market environment. The issue is then whether a more practical decentralized negotiation approach can be found that results in transmission plan solutions which approximate the system-optimal transmission plan Y_C to a satisfactory degree. The following subsection addresses this issue.

E. RE Subsidy Sensitivity Analysis

Table IX compares the SS outcomes (10^6\$) achieved under three different transmission planning approaches. These three approaches are as follows: centralized planning (Y_C) for various S_R values; FP-based negotiation (Y_N) for various S_R values, given $FP = \$12$/MWh; and LMP-based negotiation (Y_N^M) for various S_R values.

TABLE IX
EXPECTED SYSTEM NET BENEFITS (SS) UNDER THREE DIFFERENT TRANSMISSION PLANS AS S_R INCREASES

S_R	Y_N	Y_N^M	Y_C
0	0	136.39	142.55
5	137.96	136.39	142.55
10	142.55	136.39	142.55
15	142.55	136.39	142.55

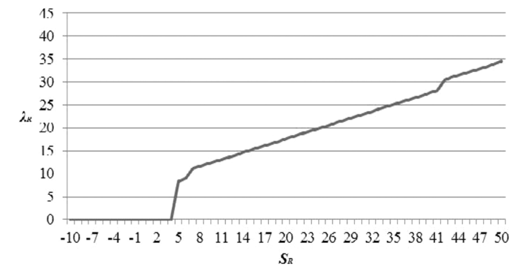

Fig. 5. FP-based negotiated payment rate (λ) as a function of S_R, given $FP =$ \$12/MWh.

When S_R is small, FP-based negotiation (Y_N) results in a relatively low SS outcome due to underinvestment relative to Y_C; no lines are selected to be built when $S_R = 0$ and only line T7 is selected to be built when $S_R = \$5$/MWh. As S_R increases, however, FP-based negotiation eventually results in a transmission plan that coincides with Y_C and achieves the same SS as centralized planning.

When S_R is \$5/MWh, LMP-based negotiation (Y_N^M) results in an even lower SS outcome than FP-based negotiation (Y_N) due to overinvestment relative to Y_C (investment in lines T6, T7, and T9). Moreover, increases in S_R have no impact on this suboptimal choice of plan. In fact, as will now be shown in greater detail, the ability to move negotiated transmission plans closer to centrally-determined system-optimal transmission plan through changes in S_R is very limited for the LMP-based case.

Additional sensitivity results for varying RE subsidy levels S_R are reported in Tables X and XI for the FP-based case (with $FP = \$12$/MWh) and the LMP-based case, respectively. Corresponding outcomes for the payment rate λ are depicted in Figs. 5 and 6. Note that this sensitivity study includes negative S_R values representing penalties rather than subsides for generating RE. Negative S_R values can arise from cost overruns, high financial charges on capital, or costs incurred from project delays.

As indicated in Table X, FP-based negotiation fails to result in any transmission plan agreement when S_R is between $-\$10$/MWh and \$4/MWh; the two parties default to their threat points. When S_R is between \$7/MWh and \$41/MWh, FP-based negotiation results in the system-optimal plan $Y_C = [1\ 1\ 0\ 0\ 0]$ and hence also in maximum SS. When S_R increases above \$42/MWh, however, FP-based negotiation results in too much transmission investment (relative to Y_C)

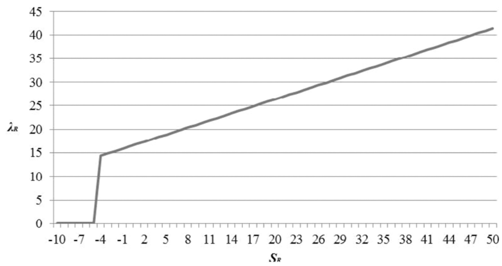

Fig. 6. LMP-based negotiated payment rate (λ) as a function of S_R.

TABLE X
FP-BASED TRANSMISSION PLAN OUTCOMES (FP = \$12/MWH) FOR VARIOUS SUBSIDY LEVELS S_R IN COMPARISON TO THE SYSTEM-OPTIMAL SOLUTION Y_C

S_R	Candidate					Match
(\$/MWh)	Y_6	Y_7	Y_8	Y_9	Y_{10}	Y_c?
-10 to 4	0	0	0	0	0	No
5 to 6	0	1	0	0	0	No
7 to 41	1	1	0	0	0	***Yes***
42 to 50	1	1	1	0	0	No

TABLE XI
LMP-BASED TRANSMISSION PLAN OUTCOMES FOR VARIOUS RE SUBSIDY LEVELS S_R IN COMPARISON TO THE SYSTEM-OPTIMAL SOLUTION Y_C

S_R	Candidate					Match
(\$/MWh)	Y_6	Y_7	Y_8	Y_9	Y_{10}	Y_c?
-10 to -6	0	0	0	0	0	No
-5 to 50	1	1	0	1	0	No

and hence in an SS outcome that is below maximum possible SS.

The findings in Table X thus indicate that, under FP-based negotiation, policymakers might be able to use the RE subsidy S_R to steer the negotiated transmission investment plan to the system-optimal plan Y_c. Indeed, a range of S_R values could achieve this purpose, lessening the burden on policymakers for finding the "right" subsidy level. However, setting S_R too low or too high could lead to underinvestment or overinvestment, respectively, relative to Y_C, resulting in system inefficiency (lower than possible SS).

On the other hand, as seen in Table XI, LMP-based negotiation never results in a system-optimal transmission plan for the tested range of RE subsidies S_R. It is important to consider more carefully the systemic reasons for this pessimistic finding.

The expected utility gain of the RE-GenCo in any transmission plan negotiation depends strongly on the price it receives for its wind power at Bus 6. In the LMP-based case, this price is given by the LMP at Bus 6, which in turn is determined as the least cost to the system of servicing one additional MW of load at Bus 6. It is to the RE-GenCo's advantage to ensure that the supplier of this "next" MW would not be his cheap wind unit but rather would be some more expensive conventional generator. By "overinvesting" in transmission in order to reduce or eliminate transmission congestion, the RE-GenCo can help to ensure that his cheap wind power will always be dispatched to maximum capacity to meet current demand. In this case any "next" MW of load at Bus 6 would have to be supplied by conventional generation, and it would be the marginal cost of this more expensive generation that would then determine the price received for wind power at Bus 6.

Although such strategic behavior on the part of the RE-GenCo wind producer leads to socially inefficient transmission investment (loss of SS), it is perfectly in accordance with the RE-GenCo's private negotiation objective: namely, maximization of own expected utility gain. As evidenced by the results reported in Table XI, this socially inefficient private behavior cannot be completely offset by RE subsidies.

These findings are further supported by the corresponding results reported in Figs. 5 and 6 for payment rate outcomes. The negotiated transmission payment rate λ increases piece-wise linearly with S_R. A step-change in λ is a necessary and sufficient indicator that the corresponding change in S_R has led to a change in the negotiated transmission plan Y. Note in Fig. 6 that the only step-change in λ occurs at the negative value $S_R = -\$5$/MWh, i.e., at a point where S_R is a tax rather than a subsidy. For all nonnegative values of S_R, the LMP-based agreement on a plan Y is not affected by the S_R level because the RE-GenCo's revenues from the LMP-based sale of its wind in the energy market under Y are sufficient to incentivize the choice of Y regardless of this subsidy.

The findings reported in this section provide support for the following conclusions. First, Nash bargaining results in fair and Pareto-efficient expected utility gains for the participants in merchant transmission investment negotiations, but it does not necessarily guarantee system optimality (maximum SS). Second, RE subsidies can be used in some cases to ensure that the negotiated plans are system optimal. Given a fixed RE contract price, RE subsidies can be used effectively to steer negotiated merchant transmission investment towards a system-optimal solution. Under market-based locational marginal pricing (LMP), however, the ability of RE subsidy settings to ensure the system optimality of negotiated merchant transmission investment is limited. This limitation needs to be recognized in the design of RE subsidies.

VI. Conclusion

Significant transmission projects are needed to integrate and deliver RE resources, especially wind generation, to meet RPS mandates. In this study a Nash bargaining negotiation methodology has been proposed for generation companies and transmission companies interested in sharing the uncertainties and market risks associated with RE integration. The Nash bargaining solution ensures fair and Pareto-efficient expected utility gains for the bargaining participants.

The analytical and case-study findings reported in this study should also provide useful guidelines to policymakers interested in integrating RE resources into grid operations. These findings show the limited ability of RE subsidies under market-based LMP to ensure that negotiated merchant transmission investment planning will result in a system-optimal outcome. On the other hand, these findings suggest that RE subsidies can effectively be used to ensure the system optimality of merchant transmission planning when RE prices are fixed in advance through bilateral contracts.

One important extension of this work would be to permit the joint consideration of RE generation and transmission investments in the bargaining process; see the Appendix for a discussion of how this could be done.

It is noteworthy that the proposed Nash bargaining approach could also be applied to negotiation between TransCos and conventional GenCos, e.g., coal or natural gas power companies, which have higher fuel costs but lower uncertainties. For TransCos, a choice to cooperate with RE-GenCos versus conventional GenCos would depend on their expected profit and their risk attitude. If their expected profit gains with RE-GenCos are less than that with conventional GenCos, TransCos will rather choose the latter. Hence, a further interesting exploration would be how to design renewable subsidies to make RE-GenCos more competitive than conventional GenCos for merchant transmission investment.

One limitation of the proposed approach as developed in the current study is that it only includes two players in the bargaining game. In the case of reinforcement of existing transmission lines, many beneficiaries arise. For such applications the proposed approach should be extended to consider more elaborate multi-player bargaining problems that include LSEs, conventional GenCos, additional RE-GenCos and TransCos, and possibly even policymakers. The extended framework could then be compared with the regulated framework to assess which option best facilitates the goal of achieving maximum net benefits for these stakeholders.

Another important extension of this work would be to consider the use of more realistic scenarios for handling RE uncertainties by exploiting more advanced scenario generation methods, for example, the moment-matching method developed in [39]. These and other extensions will be pursued in future work.

APPENDIX

The negotiation procedure presented in Section III is focused on merchant transmission projects. In reality, however, generation and transmission investments are often both needed for merchant projects and thus should be considered together in the bargaining process. An RE-GenCo could reasonably be unwilling to build an RE unit at a location if no lines currently connect this location to the grid, and a TransCo could reasonably be unwilling to construct a transmission line to a location if currently there is no need for this transmission line.

A complete Nash bargaining model that permits the joint consideration of RE generation and transmission investments is outlined in this Appendix. In this formulation, detailed operating and maintenance (O&M) costs are considered for both transmission and generation.

In practice, transmission line maintenance is performed on a scheduled basis and not based on the loadings and their frequencies. The maintenance cost is charged to the entities who receive the transmission service, e.g., generation or load. This cost is calculated in advance and put into the interconnection service agreement either in one lump sum payment using net-present value or in annualized form based on this value. The latter annualized term is denoted below by TOM_k.

Generation maintenance costs are generally divided into three parts:

1) Fuel costs;
2) Variable O&M (denoted by VOM): non-fuel costs that are a function of production;
3) Fixed O&M (denoted by FOM): salaries and other costs for scheduled maintenance, in annualized form.

In the model developed below, only VOM and FOM are included for RE units; fuel costs are ignored. In addition to the Nomenclature, the following notations are used.

TOM_k	Annualized transmission O&M cost for line k.
Ω^{CG}	Set of candidate RE units g.
ICG_g	Annualized investment cost for RE unit g.
VOM_g	Variable O&M cost for RE unit g.
FOM_g	Annualized fixed O&M cost for RE unit g.
Y_g	Indicator function indicating the investment decision to build RE unit g (1) or not (0).

The market-based expected utility functions for the RE-GenCo and the TransCo are given below. Note that the expected utility function for the RE-GenCo now also depends on the generation investment decision Y_g:

$$U_{RG}^{M} = E_{s\in\Omega_S} \sum_{t\in\Omega_T} D_t \left[\left[\mathrm{LMP}_{n(g)ts} + S_R - \lambda - \mathrm{VOM}_g\right] P_{gts}\right] - \sum_{g\in\Omega^{CG}} [\mathrm{FOM}_g + \mathrm{ICG}_g] Y_g \tag{A1}$$

$$U_T = E_{s\in\Omega_S} \sum_{t\in\Omega_T} D_t \left[\lambda P_{gts}^{G}\right] - \sum_{k\in\Omega^{\mathrm{CT}}} [\mathrm{ICT}_k + \mathrm{TOM}_k] Y_k. \tag{A2}$$

The proposed bargaining problem for this joint generation and transmission investment problem is presented in (A3)–A(15):

$$\max_{\lambda, Y_k, Y_g} U_{RG}^{M} U_T \tag{A3}$$

subject to

$$U_{RG}^{M} \geq 0 \tag{A4}$$

$$U_T \geq 0 \tag{A5}$$

$$-M \sum_{k\in\Omega^{\mathrm{CT}}} Y_k \leq \lambda_R \leq M \sum_{k\in\Omega^{\mathrm{CT}}} Y_k \tag{A6}$$

$$P_{gts} = \sum_{b\in\Omega_g^b} P_{gbts}^{G} \tag{A7}$$

where

$$P_{gbts}^{G},\ \forall t\in\Omega_T,\ \forall s\in\Omega_S = \underset{P_{ibts}^{G} P_{jbts}^{L}}{\operatorname{argmax}} \sum_{j\in\Omega_n^L} \sum_{b\in\Omega_j^b} \lambda_{jb}^{L} P_{jbts}^{L} - \sum_{i\in\Omega^G} \sum_{b\in\Omega_i^b} \lambda_{ib}^{G} P_{ibts}^{G} \tag{A8}$$

subject to

$$\sum_{j\in\Omega_n^L}\sum_{b\in\Omega_j^b} P_{jbts}^L + \sum_{k\,|\,o(k)=n} F_{kts} - \sum_{k\,|\,r(k)=n} F_{kts} - \sum_{i\in\Omega_n^G}\sum_{b\in\Omega_i^b} P_{ibts}^G = 0, (\mathrm{LMP}_{nts}), \quad \forall n\in\Omega_N \tag{A9}$$

$$0 \le P_{ibts}^G \le \bar{P}_{ib}^G, \quad \forall i\in\Omega^{TG}, \forall b\in\Omega_i^b \tag{A10}$$

$$0 \le P_{ibts}^G \le \bar{P}_{ibts}^G, \quad \forall i\in\Omega^{RG}, \forall b\in\Omega_i^b \tag{A11}$$

$$0 \le P_{gbts}^G \le \bar{P}_{gbts}^G Y_g, \quad \forall i\in\Omega^{CG}, \forall b\in\Omega_g^b \tag{A12}$$

$$F_{kts} = \frac{1}{X_k}\left[\delta_{o(k)ts} - \delta_{r(k)ts}\right], \quad \forall k\in\Omega^{\mathrm{ET}} \tag{A13}$$

$$-\bar{F}_k \le F_{kts} \le \bar{F}_k, \forall k\in\Omega^{\mathrm{ET}} \tag{A14}$$

$$-(1-Y_k)M \le F_{kts} - \frac{1}{X_k}\left[\delta_{o(k)ts} - \delta_{r(k)ts}\right] \le (1-Y_k)M, \quad \forall k\in\Omega^{\mathrm{CT}}. \tag{A15}$$

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