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Coordination of electricity transmission and generation investments

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ABSTRACT

For over twenty years, electricity market liberalization has advanced short-term market efficiency in wholesale markets, but little progress has been made on coordinated transmission and generation investments. With fast penetration of renewables, widespread of distributed energy resources and emergence of smart-grid and energy storage technologies, the stake is growing significantly higher for the long-term efficiency of liberalized wholesale markets with an aging transmission infrastructure.

This paper presents a methodology based on a general framework of two-stage stochastic optimization model for analyzing interactions between transmission and generation investments. The methodology features economic effects of prices, incentives and welfare impacts under alternative coordination approaches and cost recovery mechanisms. Application to scenarios under efficient coordination, merchant transmission, and sequential coordination are illustrated using a simple radial transmission network. Interestingly, a Boiteux-Ramsey cost sharing rule produces energy prices and social welfare impacts that appear essentially indistinguishable from those obtained under efficient coordination.

1. Introduction

Before electricity market liberalization in the 1990s, a vertically integrated utility centrally plans for transmission and generation investments. Now, a regional transmission organization (RTO) administers wholesale markets, manages system operations, and plans most transmission projects, while commercial firms choose generation investments on a merchant basis for-profit.[1] The fundamental importance of coordination of transmission and generation investments has long been recognized.[2] Previous works by Joskow and Tirole (2005), Sauma and Oren (2006), Wu et al. (2006), Hogan et al., 2010; Stoft, 2006; Léautier and Thelen, 2009, Littlechild (2012), Munoz et al. (2013), Hoffler and Wambach (2013) and Pozo et al. (2013, 2017) have contributed to a much deeper understanding of the complex issues. Nonetheless, equipped with few tools to deal with the complex reality, system planners are often caught in a perennial conundrum. With fast penetration of renewables, widespread of distributed energy resources and emergence of new technologies (e.g., smart-grid and energy storage), the stakes are growing significantly higher for the long-term efficiency of liberalized wholesale markets with an aging transmission infrastructure.

To address complex economic, reliability and policy issues, it is essential that RTO's plans recognize interactions between regulated and merchant investments.[3] This task comprises anticipating merchant generation capacity, comparing regulated and merchant transmission projects, and comparing transmission and generation solutions in terms of prices, incentives, and the distribution of costs, benefits and welfare impacts. Traditionally, such decisions were centralized in vertically integrated systems, but modern liberalized markets have rather limited means of coordinating investments in generation capacity and transmission capacity, and the idealized integrated resource planning is not an option. In the absence of forward markets that incentivize efficient coordination, transmission planning has been a perennial challenge in liberalized markets. New tools are required within an integrated framework that enables one to anticipate the incentives for merchant investments, and to estimate the impacts of merchant and regulated projects on energy prices along with the distributive effects on participants in

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[1] In the current RTO planning environment, the generation investments are proposed by the merchant developers with interconnection requests, the transmission plan could be proposed by the RTO or merchant developers. Transmission and generation planning are loosely coordinated. Some wholesale markets rely on the use of a forward capacity market to choose generation projects based on competitive auction. But there is no such forward market mechanism for transmission projects.

[2] See Joskow and Schmalensee (1983), Hogan (1992), Bushnell and Stoft (1996), Chao and Peck (1996).

[3] In this paper, for expositional clarity, the problem is cast in the institutional setting relevant to the wholesale electricity markets in the U.S., but the economic insights could be easily extended to other market settings.

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wholesale energy markets. Since the timeframe of transmission planning is generally longer than for generation, such models are necessary to enable efficient coordination of regulated transmission projects with anticipated or alternative merchant projects as a regulated transmission project and its cost allocation are subject to stakeholders' reviews in the regulatory process.

Among the sources of the problem are the respective roles of regulated and merchant investments in transmission capacity. Generation and some transmission investments are made by commercial firms on a merchant basis for profit. Most transmission investments are proposed, on a regulated basis, by a regional transmission organization (RTO) in consultation with stakeholders, including participants in the wholesale electricity markets and regulators in affected local jurisdictions, and net costs are allocated among demanders such as load serving entities or public utilities.[4]

These aspects of transmission planning are characterized by complex, often highly nonlinear, interactions. This necessitates new models ideally based on an integrated framework that allows the planner to anticipate the incentives for merchant investments, and to estimate the impacts of merchant and regulated projects on energy prices along with the distributive effects on participants in wholesale energy markets. Since the time frame of transmission planning is generally much longer than for generation, such models are necessary to enable efficient coordination of regulated transmission projects with anticipated or alternative merchant projects while a regulated transmission project and its cost allocation must be approved by stakeholders.

In this paper, we present a methodology based on a general framework of two-stage stochastic optimization model for planning and evaluating economic transmission projects. It comprises features encompassing welfare impacts, incentives, and price changes under alternative allocation and cost recovery methods (Chao and Wilson, 2013; Wilson, 1993). We illustrate applications of the approach with a simple model for scenarios under efficient coordination, merchant transmission, and sequential coordination. This paper focuses on a high-level perspective on economic insights. The model serves as a tool for evaluating the merits of alternative investment options, determining the optimal levels of generation and transmission capacity expansions resulting from merchant and regulated investments, and estimating the effects on prices, incentives and the distribution of costs, benefits and welfare impacts among market participants. The methodology could be extended for supporting the development of forward market mechanisms for efficient coordination of transmission and generation investments in the long term.

Beyond the basic requirements for an RTO to assure the security and reliability of the transmission system and provide competitive wholesale energy markets, the main issues of coordination that we address include how efficient planning responds to system changes, the roles of merchant and regulated investments, and sequencing of transmission and generation investments. In the following, we provide an overview of the main issues addressed by various scenarios that are reported in Sections 4–6.

Efficient coordination of transmission and generation planning should respond to system changes in both the short and long term. The first issue addressed here is:

- What are the consequences of an RTO's possible responses to changes in the system configuration, such as growth in demand or retirement of a large generator at a key location? A passive option is to wait for a merchant investor to add new generation capacity. Active options include a procurement auction to solicit new generation capacity, or adding transmission capacity.

The framework and the model provide tools for assessing some consequences of these options. The model can be calibrated to approximate the main features of the existing system, such as the price elasticities of small changes in demands and supplies and the costs of adding generation and/or transmission capacity at each location. Using this data, one can then calculate for each option the predicted energy prices and welfare impacts on market participants, as measured by resulting changes in consumer surplus and producer surplus at each location in the network.[5] Moreover, the model can calculate the response that maximizes social surplus, namely the sum of consumer and producer surpluses among all locations. This is just one of the possible optimization exercises that can be examined, but it is especially relevant for comparison with other options because it is an efficient response according to standard economic methodology.

Both the magnitudes and distribution of a policy option's welfare impacts are useful for understanding the different perspectives of market participants. For example, the model recognizes that a transmission line has different local effects at two locations for which exports and imports are enabled by the line. Transmission capacity complements generation capacity at the exporting node because it enables export sales; and transmission capacity substitutes for generation capacity at the importing node because it enables purchases of imports. However, demanders at these nodes typically have differing views because of the effects on energy prices.

These opposing views arise because there are winners and losers. For example, suppose that A and B are two adjacent nodes in a network and an old generator will retire at location B and two options are either (a) new generation capacity at B or (b) greater transmission capacity from location A to B. The preferences of a load-serving utility or a local regulatory agency at B might reflect primarily whether (a) or (b) will yield lower energy prices at A, but one at A could have a strong preference for (a) because new transmission capacity would encourage exports from A to B that might raise the marginal cost of generation at A and thus the energy price at A. In contrast, a generation company at A could have a strong preference for (b) for the same reason that the transmission capacity enables exports to B.

Often these different preferences occur because options for generation and transmission capacity are seen differently as substitutes or complements. In the example above, a generation company at A sees transmission as a complement to its generation capacity because it enables exports to B, whereas a utility at A obtains no complementary advantage and may be opposed to higher energy prices at A. Similarly, at B the utility sees local generation and transmission as substitutes, and if it prefers one or the other option because the energy price at B will be lower, then a generation company at B will have the opposite preference because it prefers the higher price. The model can be a useful tool for estimating the signs and the magnitudes of these welfare impacts, and thus anticipating for each option the sources of support and opposition and the strength of their preferences.

Transmission planning may include both regulated and merchant investments. The second issue addressed here is:

- How can an RTO compare merchant investment in transmission with regulated investment? A passive option is to propose regulated

[4] In the U.S., essentially all transmission investments and operations are subject to approvals by the Federal Energy Regulatory Commission (FERC). Each regional transmission organization (RTO) and independent system operator (ISO) is organized as a public benefit corporation that manages an open-access regional transmission system and conducts wholesale energy markets according to a tariff approved by FERC. Several ISOs also conduct auction markets for generation capacity sufficient to ensure transmission reliability. Some regional systems are not managed by RTOs or ISOs.

[5] The producer surplus at a location in the transmission network is the difference between energy revenue and cost, net of the cost share of any investments in new capacities. The consumer surplus is the difference between gross consumer benefit and energy revenue (estimated as the area under the demand function and above the local energy price), net of the shared cost of any investments in new capacities.

investment only if no merchant investment is offered. The active option is to propose regulated investment, if the welfare impacts of merchant investment are severe.

The model allows consideration of several versions of merchant investment, depending on who is the investor. The investor could be a transmission company, or at different locations in the network, a generation company or a utility. In each case, an investor incurs the full cost of the investment and obtains all the revenue from transmission congestion charges, and revenue from injection charges if allowed. The optimal capacity provided by transmission investment on a merchant basis takes account of secondary benefits; e.g. for a merchant line proposed by a generation company (or by an alliance with a transmission company), the profit from energy exports over the transmission line can make the investment profitable even if it incurs a loss on the line itself. Further, an investor's preferred capacity for a merchant transmission line can differ substantially from the efficient capacity because the investor does not need to consider welfare impacts on other market participants.

For the alternative of regulated investment, the model allows several versions. As a standard reference for comparisons, we often use the "first-best" efficient capacities that are chosen to maximize the total among all market participants of the producer and the consumer surpluses net of investment costs. Regulated investment can specify various cost-sharing rules, such as sharing in proportion to usage, or load served, or incremental benefit or consumer surplus. In a second-best efficient version examined in Section 4, the investment cost is recovered by the sum of congestion charges and injection charges.

These versions of merchant and regulated investment are useful chiefly to understand why a merchant investor might propose a transmission project quite different than an efficient project, and to estimate the different welfare impacts. For example, an efficient project can have a transmission capacity that still entails congestion charges in periods with peak loads, whereas an exporting generator or importing utility might prefer a capacity large enough to eliminate congestion charges. However, here we do not address more subtle considerations; e.g. a generation company might see an investment in transmission capacity for exports as profitable, but not propose a merchant project because it prefers a regulated project in which the cost is recovered from all market participants via the cost-sharing rule.

Transmission and generation investments usually take place at different times. The third issue addressed here is:

- Should an RTO's design of a regulated transmission project anticipate that subsequent merchant investments in generation capacity will be adapted to the transmission capacity provided, or should the RTO wait to adapt the transmission project to the installed generation capacities?

The simple model does not presently account for different time frames for planning and installing generation and transmission capacities, nor different service lives. However, it enables studies of several scenarios. For example, in one scenario, generation investments are made first on the assumption that ample transmission will be provided. And in another scenario, an efficient transmission project is implemented based on the currently installed capacity and then those additional generation projects that are profitable are implemented. Of special value is the model's ability to consider the Cournot version of competition between generation investments, as for instance when generation companies along a transmission line compete for sales in their local energy markets.

The organization of the remaining sections of the paper is as follows. Section 2 sets forth the basic framework. Section 3 describes the main features and assumptions of a basic model that is used to study the various policy scenarios of coordination. Sections 4–6 report on the studies of the three main scenarios: efficient coordination, merchant transmission investments and sequential coordination. Section 7 summarizes with concluding remarks. Appendix A provides the mathematical formulation for a second-best cost recovery mechanism and merchant transmission models.

2. Framework

In this section, we present the basic features of an integrated framework that enables studies of various scenarios of coordination of transmission and generation capacity investments in competitive wholesale electricity markets. It serves as an economic analysis tool for evaluating the effects of alternative investment strategies from the viewpoints of individual stakeholders. It offers a high-level perspective on major features – although necessarily it does not address the fine details of specific investment proposals. The use of mathematical formulation helps clarify complex issues that may otherwise be obscured in a policy debate. For simplicity, the main focus is limited to transmission and generation investments where consequences are primarily economic, but the underlying methodology can be generalized to address system reliability and other policy issues such as operating reserves requirements and carbon emission restrictions.

2.1. Two-stage stochastic optimization

In the following, we present a two-stage stochastic optimization framework for coordinated transmission and generation capacity expansion in competitive wholesale electricity markets, where a market-driven environment is conducive for merchant investments. We assume that decisions about new investments in transmission and generation capacities are made jointly under uncertainty in a forward timeframe, while energy trades, power flows on the electric network and prices are determined in a spot market.

The planner's objective is to maximize the expected social surplus, the sum of the consumer surplus and the producer surplus. The social welfare objective is consistent with the basic economic principle of public policy for integrated resource planning. The model informs the planner about the merits of alternative options as well as the incremental costs, benefits, and welfare impacts on stakeholders at different locations.

First, listed below are the symbols used in the basic model. We let boldface letters denote vectors, matrices or random variables.

2.1.1. Notation

$i, j, n \in N$: The set of nodes in the electric network.

$t = 1, \ldots, T$: Time periods in the second stage.

$I(Z_{ij})$: The transmission investment cost function; Z_{ij} is the capacity of link (i,j).

$\mathrm{k_n}$: The unit investment cost of generation capacity at node n.

Y_n: The generation capacity at node n.

$\boldsymbol{q}_n = (\boldsymbol{q}_{n1},\ldots,\boldsymbol{q}_{nT})$: The vector of energy consumption levels at node n over T periods.

$\boldsymbol{x}_n = (\boldsymbol{x}_{n1},\ldots,\boldsymbol{x}_{nT})$: The vector of energy production levels at node n over T periods.

$\boldsymbol{p}_n = (\boldsymbol{p}_{n1},\ldots,\boldsymbol{p}_{nT})$: The vector of energy prices at node n over T periods.

$\boldsymbol{B}_{nt}(\boldsymbol{q}_{nt})$: The gross consumer benefit of energy consumption at node n in period t.

$\boldsymbol{q}_{nt}^d = \boldsymbol{D}_{nt}(\boldsymbol{p}_{nt})$: The energy demand function at node n in period t.

$\partial \boldsymbol{B}_{nt}(\boldsymbol{q}_{nt}^d)/\partial q = \boldsymbol{D}_{nt}^{-1}(\boldsymbol{q}_{nt}^d)$: The marginal utility of energy consumption at node n in period t.

$\boldsymbol{C}_{nt}(\boldsymbol{x}, Y)$: The cost function of energy generation $\boldsymbol{x}$ and capacity Y at node n in period t with $\partial \boldsymbol{C}_{nt}(\boldsymbol{x}, Y)/\partial Y \le 0$.

$\boldsymbol{q}_{nt}^{s} = \boldsymbol{S}_{nt}(\boldsymbol{p}, Y)$: The energy supply function at node n in period t.
$\nabla_{\boldsymbol{x}}\boldsymbol{C}_{nt}(\boldsymbol{q}_{nt}^{s}, Y) = S_{nt}^{-1}(\boldsymbol{q}_{nt}^{s}, Y)$: The marginal cost of energy production at node n in period t.
$\boldsymbol{\theta}_{nt}$: The voltage angle at node n in period t.
$\boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i} - \boldsymbol{\theta_j})$: Power flow from node i to node j according to Kirchoff's laws.
β_{ij}^{n}: The power flow distribution factor on link (i,j) from power injected at node n

The basic model solves a two-stage stochastic optimization problem. In the first stage, optimal transmission and generation capacity investments strives to achieve the maximum expected net social benefit. Then, in the second stage, an economic dispatch problem is solved and market clearing prices are calculated, where the market solution forms the basis for a value function of transmission and generation capacities serving as inputs into the first stage decision model.

In the first stage, the decision problem is based on a standard optimization formulation:

$$\underset{(\boldsymbol{Y},\boldsymbol{Z})}{\text{Max}} \left\{ E[V(\boldsymbol{Y}, \boldsymbol{Z})] - \sum_{n \in N} k_n Y_n - \sum_{i,j \in N} I_{ij}(Z_{ij}) \right\} \tag{1}$$

The solution to (1) is an optimal investment portfolio of transmission and generation expansion projects that maximizes the expected social welfare net of capacity investment costs. The value function, $V(\boldsymbol{Y}, \boldsymbol{Z})$, reflects the benefits of transmission and generation capacity in serving the spot energy market. We assume that the generation investment is a smooth linear cost function, though the cost function for transmission expansion for each line, $I(Z_{ij})$, is a non-linear and function featuring economies of scale and lumpiness.

In the second stage, the market operator's problem is to clear the energy market efficiently achieving the maximal social surplus subject to network power flow and security constraints[6]:

$$V(\boldsymbol{Y}, \boldsymbol{Z}) = \max_{(\boldsymbol{q^d}, \boldsymbol{q^s}, \boldsymbol{\theta})} \sum_{n \in N} \sum_{t=1}^{T} \boldsymbol{B}_{nt}\left(\boldsymbol{q}_{nt}^{d}\right) - \boldsymbol{C}_{nt}\left(\boldsymbol{q}_{nt}^{s}, Y_n\right) \tag{2}$$

subject to

$$\boldsymbol{q}_{nt}^{s} - \boldsymbol{q}_{nt}^{d} = \sum_{j \in N} \boldsymbol{\Psi}_{nj}(\boldsymbol{\theta_n} - \boldsymbol{\theta_j}), \text{for } n \in N; t = 1, \ldots, T \tag{3}$$

$$\boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i} - \boldsymbol{\theta_j}) \le Z_{ij}, \textit{for } i, j \in N; t = 1, \ldots, T \tag{4}$$

Eq. (3) states that the net energy supply at each node equals the sum of power flows from this node to all of its adjacent nodes. Constraint (4) states that for each link, the power flow cannot exceed the thermal capacity of the link.

The Lagrangian dual problem for (2)–(4) is as follows,

$$\begin{aligned} \mathcal{L}(\boldsymbol{Y}, \boldsymbol{Z}) = \underset{\boldsymbol{p},\boldsymbol{\mu}}{\mathit{Inf}} \underset{(\boldsymbol{q^d}, \boldsymbol{q^s}, \boldsymbol{\theta})}{\mathit{Sup}} & \sum_{n \in N} \sum_{t=1}^{T} \left[\boldsymbol{B}_{nt}\left(\boldsymbol{q}_{nt}^{d}\right) - \boldsymbol{C}_{nt}\left(\boldsymbol{q}_{nt}^{s}, Y_n\right) \right] \\ & + \sum_{n \in N} \sum_{t=1}^{T} \left[\boldsymbol{p}_{nt} \left(\boldsymbol{q}_{nt}^{s} - \boldsymbol{q}_{nt}^{d} - \sum_{j \in N} \boldsymbol{\Psi}_{nj}(\boldsymbol{\theta_n} - \boldsymbol{\theta_j}) \right) \right] \\ & + \sum_{i,j \in N} \mu_{ij} \left[Z_{ij} - \boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i} - \boldsymbol{\theta_j}) \right] \end{aligned} \tag{5}$$

[6] See Chao and Peck (1996).

In equilibrium, the market clearing prices for energy for $n \in N$; $t = 1, \ldots, T$ satisfy the following first-order conditions[7]:

$$\nabla \boldsymbol{B}_{nt}\left(\boldsymbol{q}_{nt}^{d*}\right) = \nabla_{\boldsymbol{x}} \boldsymbol{C}_{nt}\left(\boldsymbol{q}_{nt}^{s*}, Y_n\right) = \boldsymbol{p}_{nt}^{*} \tag{6}$$

$$\boldsymbol{p}_{nt}^{*} = \boldsymbol{p}_{0t}^{*} + \sum_{i=1}^{N} \sum_{j=1}^{N} \mu_{ij}^{*} \beta_{ij}^{n}, \text{with } \mu_{ij}^{*}\left[Z_{ij} - \boldsymbol{\Psi}_{ij}\left(\boldsymbol{\theta}_i^{*} - \boldsymbol{\theta}_j^{*}\right)\right] = 0 \tag{7}$$

Eq. (6) shows that the spot price at each node equals the marginal benefit and marginal cost of energy. Eq. (7) indicates that the nodal price difference equals the congestion rent for transmission constraints, where μ_{ij}^{*} is the shadow price on link (i,j).

In the first stage, the optimal capacity expansion plan satisfies the following first-order conditions:

$$k_n = E\left[-\frac{\partial \boldsymbol{C}_{nt}\left(\boldsymbol{q}_{nt}^{s*}, Y_n^{*}\right)}{\partial Y_n}\right] \tag{8}$$

$$I'_{ij}\left(Z_{ij}^{*}\right) = E\left[\mu_{ij}^{*}\right] \tag{9}$$

Eq. (8) indicates that the fixed capacity cost equals the expected downward shift in the energy cost caused by the generation investment. Eq. (9) indicates that the marginal investment cost for transmission equals the expected congestion rent. These conditions do not guarantee that the total congestion revenue would be sufficient to cover the total investment costs, when as often is the case, the investments are characterized by lumpiness and economies of scale.

The two-stage stochastic optimization framework incorporates an investment value function that reflects the economic benefits of transmission and generation investment in the spot energy markets under uncertainty, and such a value function could ideally serve as the objective function in forward market mechanisms to guide efficient transmission and generation investments. (Boffino et al., 2019) Before presenting a simple model that illustrates how the basic integrated planning framework may be used to address the coordination problems posed by transmission and generation investments, it is useful to describe below several key problems of coordination posed by regulated transmission projects, further problems encountered when integrating transmission merchant projects into the overall planning process, issues involved in the regulatory process, and the three basic policy scenarios studied in this report.

2.2. Conundrums of coordination

In the following, we highlight key issues concerning the timing, nature and financing of investment decisions. We consider three perennial conundrums that face transmission planners in coordination with merchant generation investments: 1) which goes first, generation or transmission? 2) which should it be, generation or transmission? and 3) how might regulated projects be financed?

2.2.1. Problem 1 – which goes first, generation or transmission?

The merit of an economic transmission project is sometimes viewed as akin to the value of a highway. In this view the transmission network is a desirable infrastructure that enables suppliers' outputs to be delivered to demanders with the least overall cost. One version argues that the network capacity should eliminate congestion whenever the benefits exceed the costs, and therefore, investments in additional transmission capacities should be adapted to whatever is the spatial pattern of generators' locations and capacities relative to the spatial pattern of loads.

[7] The equilibrium condition assumes that the cost functions are convex. When the cost functions are non-convex, the optimal solution to the Lagrangian dual problem is connected with a quasi-equilibrium. See Chao (2019).

An alternative view argues that the transmission network should establish a backbone of available capacities that then guides investors in generation capacities when choosing their locations. This view is reinforced by recognition that, compared to generation capacity, transmission capacity is more expensive, difficult to locate, takes longer to build, and has a longer service life, and therefore, transmission investments should establish corridors for moving power to metropolitan load centers, which cannot be moved.

We consider alternative scenarios in which either transmission capacities are established first and generation capacities adapt to it, or the reverse. We do not pretend to resolve the fundamental differences between these views about the role of the transmission system. Rather, our aim is to illustrate that our proposed framework and model can be used to obtain quantitative predictions, based on specific data about investment costs, about the economic consequences for market participants from these alternative approaches to transmission planning.

Implicit in our framework is that each of the two views described above omit the additional considerations that we address. Both the "network as highway" and "network as backbone" views focus on how best to locate power generation and its transport to load centers. Our analysis identifies the efficient solution for each of the two scenarios studied, and goes further to predict the resulting spatial distributions of prices, and computes too the welfare impacts on producers and consumers at each node in the network. The differences in welfare impacts are useful information for transmission planning because energy market participants eventually pay for regulated transmission projects.

2.2.2. Problem 2 – which should it be, generation or transmission?

A frequent situation in transmission planning is that a solution must be found to an impending change at a single node in the network, such as retirement of an old generator or growth in the load there. In either case the question can be whether to augment transmission capacity from another node with low-cost power supplies, or to rely on merchant investment in new generation capacity at that node. This problem can be explicit when a firm proposes a new generator that can substitute for import capacity.

Our framework addresses this problem by considering, for each alternative, the price and welfare impacts on suppliers and demanders at both the import and export nodes. The advantage of this approach is that it recognizes that the perceived merits of economic transmission projects typically depend on the differing viewpoints of the various affected parties. Their differing views stem ultimately from the fact that a transmission line is not purely a substitute for generation, nor purely a complement, but rather some of each. For both a utility and generator at the import node, the generation and transmission solutions are substitutes, although the utility prefers the solution with lower prices and the generator with higher prices. At the export node, a generator sees the augmented transmission capacity as a complement because it enables power sales over the line to the import node, but again a local utility and generator differ if the exports raise prices at the export node. At both nodes, the matter is further complicated by the allocation of cost recovery for the transmission capacity.

The view embodied in our framework is that transmission planning is better informed about the consequences of one solution or the other if predictions about the price and welfare effects on both parties at both nodes are quantified by predictions such as those obtained from the model used here.

2.2.3. Problem 3 – how might regulated projects be financed?

A regulated transmission project requires cost recovery to be allocated among market participants. Actually, because generation is on a merchant basis, cost recovery is usually allocated among consumers, as for instance in the case of a grid charge paid by utilities. Often the allocation is obtained from the simple formula of cost sharing in proportion to load served. Because the model here provides predictions of the welfare impacts on consumers at each node, it is potentially useful as the basis for allocating cost sharing in proportion to the welfare gain obtained by those who benefit – and the model allows as one option that this formula is used.

Two further possibilities are included in the model. Besides the first-best efficient plan, the model calculates two second-best constrained-efficient plans in which it is required that the cost of the transmission capacity chosen is recovered from revenues. In the first version the revenue consists solely of congestion charges, and in the second version the revenue consists of injection charges in addition to congestion charges.

These alternatives of cost allocation by formula and cost recovery from revenues pose a policy issue that can be distilled as follows. The first-best plan is more efficient but its effects on consumers depend on the cost allocation formula. The second version of the second-best plan is often only slightly less efficient (as will be seen in the scenarios studied later) but it is self-financing or market-based cost recovery. It operates essentially the same as tolls that recover the costs of bridges, turnpikes, and subways, but charges more when there is congestion (as is now done on some highways with congestion during commute hours).

An advantage of the framework proposed here is that the model is cast in terms of a two-stage stochastic optimization problem consistent with the architecture of forward and spot markets. Because of this formulation it is possible to compute the second-best plans, and then to compare the efficiencies of the first-best and second-best plans. The results for the scenarios studied here indicate that in some cases the efficiency loss is so small that disputes over cost allocation can be averted by relying on a market-based cost recovery mechanism.

2.3. Role of merchant transmission investments

Merchant investments depend on a decentralized process in which transmission and generation investments are guided by the private incentives of for-profit firms. The appeal of merchant investment lies in its reliance on market-driven competition to determine the location and levels of investments in new transmission and generation capacities – the "invisible hand" of investment incentives based on self-interest. Thus by shifting business and operational risks from consumers to investors, it obviates the need for the regulatory mechanism of cost recovery and facilitates efficient coordination in ways that allow investors to exploit complementarities between transmission and generation capacities.

A liberalized market-based system depends on merchant investments in generation capacity, and also allows merchant investment in transmission capacity. Merchant investment in transmission capacity expansion is appealing because it places the financial risks of investment on investors rather than consumers, while bypassing the bureaucratic processes for regulated transmission companies. Integrating merchant transmission into transmission planning poses several coordination issues that we now elaborate. In each case we argue that a full analysis of predicted prices and welfare impacts provides useful information for resolving issues during the transmission planning process.

The simplest case is capacity proposed by a commercial firm specializing in transmission. Because its cost recovery and profit derive from fees such as congestion charges and/or injection charges, its preferred capacity is typically too small to eliminate congestion in periods with peak loads. The policy issue appears when the efficient regulated transmission capacity is substantially larger – as will be seen in the scenarios studied in Sections 4–6. Even though the merchant capacity is self-financed, while the regulated capacity requires an allocation of cost recovery among market participants, a full comparison of the two options can benefit from predictions of the price and welfare impacts among all affected parties.

2.4. Regulatory process

A transmission project must be approved by regulatory agencies, and if more than one plan is proposed then they choose one. Without attempting here to model regulatory processes, we mention three features.

First, among the relevant considerations are the benefits and costs for market participants. As will be seen later, the project designs proposed by different merchant investors can differ greatly and have much different impacts on the distribution of benefits and costs among market participants. These differences stem from different incentives. While an efficient design maximizes the aggregate benefits net of costs among all market participants, a merchant investor's main incentive is to maximize its own return from the project, ignoring the adverse effects on other parties. For example, a new transmission line can raise the profits of generators who can export energy over the line, but it can also raise the local price of energy and thereby disadvantage local consumers.

Second, if the motive for a new transmission line is to enable efficient energy exchanges, rather than to improve security or reliability, then regulatory agencies might prefer a merchant project if one is proposed, rather than a regulated investment for which the cost must be recovered from market participants. Thus regulated investment is usually the preferred option only when no merchant investment is proposed. Anticipating incentives for merchant transmission investments is therefore an important ingredient of the planning process at an RTO.

Third, when a transmission project is proposed, there are often three parties with diverse interests. One party includes the suppliers at the export node and the demanders at the import node, since they stand to gain from the new transmission capacity. The transmission project facilitates and thus complements the generation investment at the export node. A second party includes the demanders at the export node and the existing suppliers at the import node, since they stand to lose. These two groups are chiefly affected by the resulting higher and lower energy prices at the export and import nodes, respectively. The third party is a potential supplier at the import node who offers a substitute for the transmission line in the form of merchant investment in new generation capacity. Thus, the regulatory process is often contentious. Estimates of the magnitudes of the welfare effects on these parties are often useful in reaching a compromise.

3. Basic model

In this section, we describe the main features of the analytical model that is used to study the various policy scenarios of coordination. We begin with several simplifying assumptions.

We assume that the transmission network and the demand and supply functions at each node are known and stationary, except for investments in new transmission or generation capacity.[8] As described later, the model first establishes a status quo or baseline for existing capacities, which is, by construction, the efficient generation capacity levels before any transmission capacity is built, and then evaluates investment projects as incremental expansion from the baseline. We allow for two periods with differing demands, named the peak and off-peak periods. These periods are assumed to be synchronous for all nodes, i.e. peak periods occur simultaneously. Our implementation allows specification of any duration of the peak period, but the examples reported here assume that the peak and off-peak periods have equal duration.

We assume that each generation companies participates in the ISO's energy markets on a merchant basis and not regulated, and that wholesale energy markets are competitive; specifically, the energy price at a node is modeled as always the same as the locational marginal cost of generation, though it allows a cap on the nodal energy prices, as this is a common feature of energy markets in the U.S. Thus, investments in capacity are the only sources of market power. The Cournot model of competition is used in scenarios that have oligopolistic GenCos.

We assume that the aggregate demand and supply functions at each node are known; e.g. the supply functions are the same as generators' marginal costs. A transmission company's revenue is derived from transmission fees and congestion charges. We measure generators' benefits at each node by the *producer surplus*, which is just the net revenue that is the difference between energy revenues, based on the local price of energy, and total generation costs measured as the area under the supply curve. We measure demanders' benefits at each node by the *consumer surplus*, which is the area under the demand function and above the local energy price. For both generators and demanders, these are gross benefits before subtracting any allocated costs of transmission capacity to obtain net benefits.

We observe that using the *social surplus* – the sum of the producer and consumer surplus – to measure the aggregate benefit of a project, and to verify whether the overall design of a project is efficient, is consistent with the objective of wholesale market design to maximize the market surplus, and it is a standard measure accepted by regulatory and policy agencies for cost/benefit and policy analyses. At the same time, such practice invokes the so-called ‘compensation principle’ often used in economic studies. This principle is based on the argument that if aggregate benefits are maximized in the design of many projects over time, with no compensation provided to those participants affected adversely by each individual project, it might still be likely that each participant will benefit overall from the many projects undertaken. Since there is no guarantee that the first-best outcome will meet the Pareto criteria, the model can help identify the compensation to adversely affected participants from those who benefit that is required for each project individually to obtain a “fair” allocation of benefits, and thus implies how the burden of cost recovery is shared.

3.1. Model formulation

For simplicity, in the basic model, we assume a network configuration with three nodes in a radial tree structure, designated A – B – C, or $N \equiv \{A, B, C\}$, where node B is designated as the hub located between nodes A and C. The formulation can be extended to a mesh network with loop flows.[9] We ignore transmission losses. Investments in transmission capacity are allowed only between nodes A and B and between nodes B and C.

We assume that the planner decides on new investments in transmission and generation capacities in advance, perhaps in a coordinated forward market, before electricity demands, supplies, and prices as well as power flows on the electric network are determined in a spot market. The planner's objective is to maximize the social surplus, the sum of the consumer surplus and producer surplus.

In the spot energy market, we consider two periods, peak and off-peak periods, denoted by 1 and 2 respectively, or $t = 1, 2$. For the scenarios studied here, we assume that at each node and in each period the price elasticities of energy demand and supply are constants, and the marginal costs of new generation capacity are constants. We assume that new transmission capacity between two nodes also has a constant marginal cost, but we also allow a fixed cost that is independent of the size of the new capacity. In other words, the transmission investment

[8] While the assumption of stationarity is a good first approximation, further research is needed for applications if demand and supply functions are evolving in a dynamic manner under uncertainty.

[9] Within a meshed power grids, Kirchhoff Laws create network externalities associated with loop flows causing new complementarities in ways that would increase the complexities as well as the benefits of coordinated investments of transmission and generation. For the illustrative case, the “transportation” network model suffices, and there is no need to represent Kirchhoff Laws within a radial structure. The basic framework can be extended in a straightforward manner to more realistic cases. See Hogan (1992), Chao and Peck (1996), Munoz, et al. (2013).

cost $I(Z)$ which is a function of the size of transmission capacity (Z):

$$I(Z) = f + \nu Z,$$

where f and v denote fixed and marginal variable costs, respectively. In an actual application, the fixed and marginal costs of new transmission capacity are unique to each project.

At each node and in each period, the demand and supply functions have the form

$$D(p) = ap^{-\varepsilon} \text{ and } S(p, Y) = Y^{\alpha}\left(\frac{p}{c}\right)^{\sigma}$$

where p is the local nodal price of energy in that period. The parameter ε is the price elasticity of demand, and σ is the price elasticity of supply (which is positive). The factor Y^{α} affecting the supplied quantity depends on the generation capacity Y installed at that node and thus varies depending on investment in generation capacity. The scale elasticity parameter α is either 1 or somewhat less to account for decreasing returns from incremental capacity. The parameter a in the demand function and the parameter c in the supply function are fixed.

In an actual application, these parameters can be calibrated by using actual market data, and typically one would use multi-period demand functions and thus allow for more than the two periods used here for peak and off-peak demand conditions. For relatively small changes from the baseline, it is useful to estimate the price elasticities from the aggregates of the demand and supply functions submitted in the energy markets by market participants at each node. Similarly, for an RTO that conducts procurement auctions, the marginal costs of new generation capacity are estimated from participants' offers of incremental generation capacity.[10]

Here, however, our purpose is limited to illustrating how the model can be used and useful in examining policy issues such as those outlined above. Therefore we posit a particular baseline and use calibrated values of demand and supply price elasticities, and costs of generation and transmission capacities.

We assume that the energy market is competitive in both the peak and the off-peak periods. Thus the market price equals the marginal benefit as well as the marginal cost of electricity, and we assume further that the demand function equals the inverse of the marginal benefit function and the supply function equals the inverse of the marginal cost function. Assuming that the marginal cost of generation capacity is k, we posit the gross benefit and total cost functions as follows,

$$B(q_{n1}, q_{n2}) = \sum_{t=1}^{T}\left[\left(\frac{1}{1-\varepsilon}\right)\left(a_{nt}\hat{p}^{1-\varepsilon} - \varepsilon a_{nt}^{\frac{1}{\varepsilon}} q_{nt}^{1-\frac{1}{\varepsilon}}\right)\right],$$

$$C_n(x_{n1}, x_{n2}, Y_n) = \sum_{t=1}^{T}\left(\frac{\sigma}{1+\sigma}\right)\frac{c_{nt} x_{nt}^{1+\frac{1}{\sigma}}}{Y_n^{\frac{\alpha}{\sigma}}}$$

Then, the marginal benefit and marginal cost functions can be derived as follows,

$$\beta_{nt}(q_{nt}) \equiv \frac{\partial B_n}{\partial q_{nt}} = \left(\frac{q_{nt}}{a_{nt}}\right)^{-\frac{1}{\varepsilon}}$$

$$\gamma_{nt}(x_{nt}, Y_n) \equiv \frac{\partial C_n}{\partial x_{nt}} = c_{nt}\left(\frac{x_{nt}}{Y_n^{\alpha}}\right)^{\frac{1}{\sigma}}$$

[10] Some RTOs and ISOs in the U.S. conduct such auctions to ensure sufficient generation capacity to meet reliability and security requirements.

The demand function equals the marginal value of consumption, and the supply function equals the marginal cost of production, so

$$D_{nt}(p) = \beta_{nt}^{-1}(p) = a_{nt}p^{-\varepsilon}$$

$$S_{nt}(p, Y_n) = \gamma_{nt}^{-1}(p|Y_n) = Y_n^{\alpha}\left(\frac{p}{c_{nt}}\right)^{\sigma}$$

For the illustrations here, we first calculate the efficient plan, including generation and transmission capacities based on the specified elasticity and cost parameters. For subsequent studies of various scenarios, the baseline's generation and transmission capacities are taken as existing capacities.

For studies of scenarios, the model assumes in the efficient case of regulated transmission investment that the capacity levels of both generation and transmission maximize the aggregate net benefits, i.e. the social surplus of all market participants net of investment costs. Recall that all investments decisions are made subject to the constraints that the total energy demand and supply in each period are in balance and that the power flow on each line does not exceed the line capacity. The congestion charge for transmission between two nodes is the difference between the wholesale energy prices at the two nodes, net of the injection charge if there is one.

In the case of merchant investments, we assume that the merchant company chooses capacity levels to maximize its net profit under the same set of system balancing and power flow constraints, with the additional assumption that all remaining participants act competitively. This assumption introduces additional constraints on merchant investment decisions in the form of competitive equilibrium conditions. See Appendix A for a detailed mathematical formulation that includes each of the scenarios studied here.

Fig. 2-1 illustrates the market trading and power flows between two nodes A and B.

3.1.1. Model parameters and scenarios

In Tables 3-1 and 3-2, we summarize the parameters of the model for the scenarios reported here. The peak and off-peak periods each account for 50% of a year.

Below are several observations:

- At each node, if all nodes have the same energy price, the demand scale factor is twice as high in the peak period as in the off-peak period.
- Price elasticity of demand at every node and in every period is -0.2. That is, a 10% increase in the energy price decreases demand by 2%.
- Price elasticity of supply at every node in every period is $+0.5$. That is, a 10% increase in price increases supply by 5%. This corresponds to a marginal cost curve that is locally approximated by a quadratic function of a generator's output rate. The scale elasticity is $\alpha = 0.9$ at all three nodes.
- Both the scale factors of demand and the marginal costs of generation

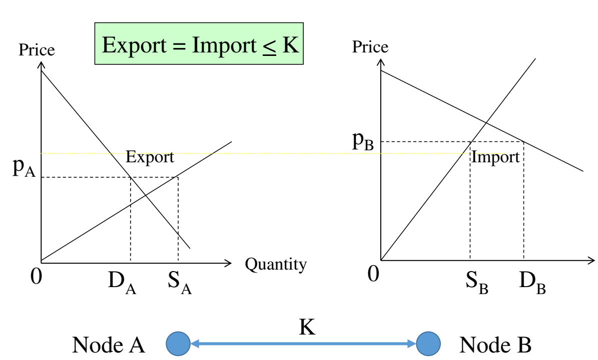

Fig. 2-1. Market trading and power flows between two nodes.

Table 3-1
Demand and supply parameters.

	Node A	Node B	Node C
Demand scale factor in the peak period	200	400	600
Demand scale factor in the off-peak period	100	200	300
Demand price elasticity	−0.2	−0.2	−0.2
Supply scale elasticity	0.9	0.9	0.9
Supply scale factor	40	40	40
Supply price elasticity	0.5	0.5	0.5
Incremental cost of generation capacity ($/MW)	40	60	80

capacity increase as one moves from node A to B to C, while the incremental cost of transmission capacity declines from A-B to B-C.

The calculation of the baseline establishes the existing generation capacities, and the resulting nodal energy prices based on the above specification of elasticities and cost parameters. In the scenarios studied in the next sections the existing generation capacities are available at no cost.

3.2. Basic coordination scenarios

In this paper, we consider scenarios that address three basic coordination scenarios: efficient coordination, merchant investments, and sequential coordination. Below is a quick preview.

3.2.1. Efficient coordination

In Section 4, we study the efficient coordination scenario and compare it with scenarios of zero capacities and later use it as a baseline for comparing other scenarios including one with unconstrained transmission capacities. Efficient coordination aims to ensure that transmission and generation investments are planned like in a vertically integrated utility or ideally in a jointly optimized forward transmission and generation capacity market. For regulated transmission projects undertaken to provide efficient infrastructure, market revenues may not be sufficient to recover the investment costs and thus it may be difficult to attract merchant investors. Cost recovery and allocation methods are important issues.

In this scenario, the net investment cost (net of any revenue from injection and/or congestion charges) must be recovered from market participants according to a specific allocation rule. We start with two approaches for cost allocation: first, proportional to load level, and second, proportional to the change in consumer surplus (consistent with the beneficiaries-pay principle). The distributional impact of a regulated project is important because the burden of cost recovery is widely shared, and an efficient plan may induce adverse effects on some participants, as for instance when new transmission capacity from an export node A to an import node B raises prices for consumers at A. Such a cost sharing rule affects the distribution of social surplus among participants but not the overall efficiency.

Then, we consider a second-best plan for recovering the costs of regulated transmission projects, called Boiteux-Ramsey plan, without requiring a separate cost sharing rule. This plan also maximizes social surplus, subject to the constraint that market revenues suffice to recover the project costs, but assumes that there is also market revenue from an injection charge.[11]

Table 3-2
Transmission cost parameters.

	Line A-B	Line B-C
Fixed cost ($Million)	200	200
Variable cost ($/MW)	10	5

3.2.2. Merchant transmission

In Section 5, we study coordination through merchant investments. We consider merchant projects that add generation capacity at a single node, and merchant projects that add transmission capacity between two adjacent nodes, or both transmission capacity and generation capacity if a generation company participates in the project. The investor in a generation project is assumed to be a company specializing in generation, called a *GenCo*. A transmission project is undertaken by a company specializing in transmission, called a *TransCo*. However, we also consider natural alliances between any two or three among a TransCo, a GenCo, and a Utility (at different nodes) in which they share investment costs and subsequent net revenues. A consortium that includes a GenCo can invest simultaneously in transmission and generation capacity.

We study several cases of merchant investment that include transmission capacity. In one case a project is undertaken by a TransCo that uses revenues from transmission fees, injection charges, and/or congestion charges to recover its costs. In other cases a project is undertaken by a local GenCo seeking expanded transmission capacity for energy exports, or by a local utility seeking expanded transmission capacity for energy imports. A more complicated example is a GenCo at node A and a utility at node B that invest jointly in generation capacity at A and transmission capacity between A and B, and perhaps they include a TransCo as a partner or contractor to build and maintain the transmission line. We do not distinguish how partners in a consortium share costs and revenues, and assume only that their objective is to maximize the total of their net benefits.

Merchant investors pay the direct costs of construction and operation, and expect their own benefits to be sufficient to cover these costs. We use measures of the producer and consumer surplus to predict the resulting distribution of net benefits among all market participants, but typically merchant investors are not required to take explicit account of distributional effects in the design of their project. That is, investors' net profit is the main determinant of the project design.

3.2.3. Sequential coordination

In Section 6, we consider sequential coordination in which transmission and generation investments are decided in sequence as a long-term planning strategy. The policy issue addressed is whether transmission investments should lead or follow generation investments. This issue was moot in vertically integrated systems because transmission and generation capacities were planned together. But in modern liberalized systems with merchant generation, the conundrum of 'which goes first' is a major issue. In one view, the transmission network should be the backbone that facilitates and guides merchant investors about where best to locate and how much generation capacity to install. This view is encouraged by the longer times for planning and building transmission lines, and their longer useful lives, compared to generation capacity. This view is examined by Sauma and Oren (2006) and Munoz et al. (2013) which show that the magnitude and location of the best transmission investment plans are likely to change when the responses of merchant generation expansions are taken into consideration. In the alternative view, transmission capacity is built to take best advantage of prior merchant investments in generation capacity. The second view is endorsed implicitly when an ISO considers regulated investment in transmission capacity only when the benefits are substantial and no

[11] These cost sharing alternatives are derived from the Boiteux-Ramsey plan rule. Ramsey–Boiteux pricing maximizes social welfare function subject to a revenue constraint. Frank Ramsey (1927) developed the pricing rule in the context of taxation. Boiteux (1956) rediscovered the same result in the context of natural monopolies with decreasing marginal costs, which would suffer revenue deficiency if it is required to price its output at the marginal cost.

merchant investments are proposed. The two views often collide, as when new transmission capacity would enable imports to a node, and the Genco at that node objects that it could add generation capacity that would substitute for the transmission capacity.

Here we study two scenarios.

- In the first scenario, efficient proactive regulated investment in the two transmission capacities occurs first, and after this, at each of the three nodes a merchant investor chooses its optimal generation capacity. Then, the model computes the optimal generation investment at each node individually (assuming no new generation capacity at other nodes), and also solves for the Cournot equilibrium among all three generators as though they act like oligopolies.
- In the second scenario, optimal generation capacities are computed first on the assumption that there will be no transmission congestion, and then sufficient transmission capacity is provided to eliminate congestion. This is done conservatively for each line A-B and B-C and the affected GenCos, and also for both lines simultaneously and all three GenCos at nodes A, B, and C.

4. Efficient coordination

In this section, we study efficient coordination of transmission and generation planning. We consider a planning process in which transmission and generation investments are set to maximize the social surplus net of investment costs over all market participants. We assume that regulated transmission projects are undertaken to provide beneficial infrastructure from which revenue is insufficient to recover investment costs. In the following, we study three main topics: how efficient coordination works in comparison with a baseline and an unconstrained transmission system, how it recovers investment costs, and how it responds to changes in the system.

First, we compare efficient coordination with two extreme scenarios – a generation-only system with no transmission, and a generation system within an unconstrained transmission system. We consider a system consisting of three separate regional systems, or three nodes, assuming that transmission and generation investments are advantageous for the three node system. The Baseline is an optimal generation-only system with no transmission capacities. Efficient Coordination represents an optimal expansion plan for both transmission and generation capacities, starting from the Baseline. Unconstrained Transmission represents an optimal generation expansion plan from the Baseline obtained with sufficient transmission capacities so that there is no congestion. Table 4-1 compares the results for the three scenarios, Baseline and Unconstrained Transmission.

As shown in Table 4-1, the efficient plan adds in total 119 MW of transmission capacity at $1.3 billion and 94 MW of generation capacity at $19.1 billion. In comparison, the unconstrained transmission system adds in total 118 MW of transmission capacity and 133 MW of generation capacity, which are respectively 52% and 41% greater than those with the efficient plan. In this scenario, while the transmission investment is increased by 39% from $1.3 to $1.8 billion, the generation investment is increased merely by 3% from $19.1 to $19.7 billion. Overall, the transmission investment is often overshadowed by the generation investment, and the total investment is increased modestly by 5%. Transmission investment can have significant leverage, making it possible to shift generation from nodes B and C to node A and increase the investment in more efficient technologies.

Table 4-2 shows the competitive energy prices in market equilibrium for the three scenarios. In the Baseline scenario, there is no transmission system connecting the three nodes, and the nodal energy prices vary all over the system during both peak and off-peak periods. On the other hand, with an unconstrained transmission system, the nodal prices are uniform. The variability of the spot energy price for the Efficient Coordination scenario lies between the extreme scenarios. With efficient coordination, the nodal prices vary during the peak period but are uniform during the off-peak period. These price patterns can be explained by several factors.

In general, nodal prices are affected by local market conditions. In the Baseline scenario, for instance, the price at node A is the lowest because it has efficient low-cost supply technology with low demand (perhaps due to end-use energy efficiency), while the price at node C is the highest because it has the highest demand and the highest cost supply technology. However, transmission investment tends to homogenize the differences among regions on the system. With unconstrained transmission, every consumer has equal access to low cost supply. As a result, the differences in nodal prices disappear. For instance, the prices during the peak and off-peak periods are $68/MWh and $25/MWh, which are very close to the lowest nodal prices, $67/MWh and $25/MWh, in the Baseline scenario with no transmission. The efficient plan eliminates congestion only during the off-peak period, resulting in a uniform price of $27/MWh. During the peak period, however, the nodal price differences remain, though less pronounced than in Baseline, and the congestion costs reflect the transmission investment costs. For example, the peak-period price of $79/MWh at node C is $5 higher than the price of $74/MWh at node B, which in turn is $10 higher than the price of $64/MWh at node A. thus, with Efficient Coordination, the peak-period congestion rent recovers the marginal investment cost of transmission capacity.

Table 4-3 shows the Baseline reference welfare levels, net of investment costs.

As shown in Table 4-4, Efficient Coordination achieves a social surplus gain of $1.41 billion above the Baseline, compared to $1.15 billion with Unconstrained Transmission.

Despite the overall efficiency gains, the distributive effects are important among individual participants. Consumers generally benefit from transmission expansion because they gain access to lower cost supplies. As shown in Tables 4-4, with Efficient Coordination, consumers as a group gain $13.3 billion, and with Unconstrained Transmission, they gain an even greater amount of $16.1 billion. On the other hand, producers tend to lose from expanded transmission and generation capacity as they face more competition. As a group, producers lose $11.9 billion and $14.9 billion, respectively, with Efficient

Table 4-1
Comparing transmission and generation capacity expansions and investments.

Capacity expansion	Line or node	Baseline	Efficient coordination	Unconstrained transmission
Transmission (MW)	A-B	0	66	105
	B-C	0	53	76
	Total	0	119	181
Generation (MW)	A	106	191	237
	B	181	189	183
	C	241	242	241
	Total	528	622	661
Investment				
Transmission (in $billion)		0	1.32	1.84
Generation (in $billion)		0	19.11	19.71
Total (in $billion)		0	20.43	21.54

Table 4-2
Energy market prices (in $/MWh).

	Node	Baseline	Efficient coordination	Unconstrained transmission
Peak period	A	67	64	68
	B	91	74	68
	C	112	79	68
Off peak period	A	25	27	25
	B	34	27	25
	C	42	27	25

Table 4-3
Welfare levels for baseline (in $billion).

Node	Consumer Surplus	Producer Surplus	Social Surplus
A	17.13	4.73	21.86
B	29.36	12.07	41.43
C	37.80	21.43	59.23
Total	84.29	38.22	122.51

Table 4-5
Cost allocation rules with efficient coordination (in $million).

Node	Load sharing	Incremental benefit
A	68	3
B	133	101
C	199	296
Total cost	400	400

Coordination and Unconstrained Transmission. This suggests why generators tend to resist policies that promote market liberalization and transmission expansion initially.

On a more granular level, as shown in Table 4-4, Efficient Coordination increases the social surplus for all three nodes and the gain is the highest at node C at $0.94 billion. Transmission expansion promotes market trading between regions and reduces the price in an import region (node C) but raise the price in an export region (node A). Therefore, consumers in an import region and producers in an export region benefit from expanded trading opportunities, but producers in an import region and consumers in an export region lose. With conservative transmission expansion, the consumers surplus at node A (an export region) drops by $0.4 billion even though consumers as a group benefit from unconstrained transmission. On the other hand, the producers at node A gain $0.27 billion with Efficient Coordination and $0.68 million with Unconstrained Transmission. This suggests why consumers in low cost regions tend to resist policies that promote transmission expansion, often resulting in contentious policy debates when these consumers are expected to bear some share of the transmission expansion cost according to the cost sharing agreement. It also explains why regions with high energy costs tend to lead market liberalization, and low costs states are more likely to retain vertically integrated utilities with cost-based rates.

4.1. Cost sharing rules

Next, we consider the cost sharing rule to recover the regulated transmission investments including both administrative and market-based approaches. Table 4-5 shows the cost allocation results under the two methods for recovering the fixed transmission cost of $400 million for the two transmission lines. We start with two administrative cost allocation methods, called load sharing and incremental benefit, assuming that they do not affect the overall efficiency. The load sharing method common for price insensitive consumers allocates the fixed transmission cost to consumers in proportion to their loads. An alternative approach, the incremental benefit method, allocates the cost to price sensitive consumers in proportion to their net benefits, as measured by the increase in the consumer surplus, relative to the Baseline. Compared to the load sharing method, the Incremental benefit method seems more equitable. It reduces the cost burden for consumers at nodes A from 17% to 8% and that for consumers at node B from 33% to 25%. At the same time, it increases the cost share for consumers at node C, from 50% to 74%, because they realize the greatest net benefits.

However, these two cost sharing rules suffer the common pitfalls of all administrative procedures, which include well-documented bureaucratic inefficiencies and vulnerabilities to political capture. To remedy these shortcomings, we consider a second-best cost recovery mechanism based on a two-part tariff with energy price and injection fee, called the Boiteux-Ramsey plan which by design (see Appendix A), maximizes the social surplus, but subject to the constraint that revenues from the project suffice to recover costs. It works by imposing on each producer an injection fee and sets the energy and injection prices in such a manner that the net revenues can fully pay for the investment costs.

As shown in Table 4-6, under the Boiteux-Ramsey plan with injection fee produce energy prices that are very close to those with Efficient Coordination. As shown in Table 4-7, the Boiteux-Ramsey plan yields an incremental social surplus of $1.41 billion above the Baseline, practically no different from Efficient Coordination. Overall, the first-best and the second-best plans are essentially the same. A key advantage of the second-best cost recovery plan is that it is self-financing and avoids the administrative cost allocation mechanism.

Next, we apply the model to scenarios of possible responses to impending changes in the system configuration. The emphasis here is on short-run analyses of the impacts of incremental changes to the baseline. We illustrate efficient responses to changes in generation capacity and demand.

- Retirement of some generation capacity at any one node, and
- An increase in demand at any one node.

In each case, we assume that the magnitude of the change is 10% - that is, a decrease of 10% in the generation capacity, or a 10% increase in demand, at that node. Thus, there are six cases corresponding to the three nodes A, B, C, and the two changes in generation capacity or demand.

Although the full capability of the model can be applied to each of these six cases, here we report results only for analyses based on a first-best efficient response. However, we distinguish three responses for each of the six cases described above.

- Transmission response: optimize the incremental investments in transmission capacities.
- Generation response: optimize the incremental investments in generation capacities.

Table 4-4
Welfare impacts of efficient coordination (in $billion from Baseline).

Node	Consumer surplus	Producer surplus	Social surplus
Efficient coordination			
A	0.05	0.27	0.31
B	3.33	(3.14)	0.15
C	9.83	(8.98)	0.94
Total	13.27	(11.86)	1.41
Unconstrained transmission			
A	(0.40)	0.68	0.28
B	4.10	(4.27)	(0.16)
C	12.39	(11.35)	1.04
Total	16.09	(14.93)	1.15

Table 4-6
Two-part Tariff Boiteux-Ramsey Cost Recovery Plan (in $/MWh).

Period	Node	Energy Price	Injection fee
Peak	A	65	0.66
	B	75	0.71
	C	80	0.59
Off Peak	A	27	0.28
	B	27	0.27
	C	27	0.20

Table 4-7
Distributive welfare effects of cost recovery plans (in $billion).

	Node	Load Sharing	Incremental Benefit	Two-part Tariff
Consumers surplus	A	0.05	0.11	0.07
	B	3.29	3.33	3.32
	C	9.92	9.83	9.99
Producers surplus	A	0.27	0.27	0.23
	B	(3.14)	(3.14)	(3.18)
	C	(8.98)	(8.98)	(9.02)
Total		1.41	1.41	1.41

- Coordinated response: optimize the incremental investments in both generation and transmission capacities.

Applying these three response modes to the two cases yields six scenarios to be analyzed for each of the three nodes. Here we display only the results for changes at the hub, node B.

Table 4-8 shows the capacity increments for each of the six scenarios. We note that the transmission response and the generation response offer competing substitutes to meet the demand created by the generation retirement or demand growth at node B. The two approaches signify the substitutability between transmission capacity in line A-B and generation capacity at node B. For the third approach, the coordinated response leverages on the complementarity between capacity increments in line A-B and those in generation at node A, because the capacity of line A-B facilitates energy export from node A. Thus their values are mutually enhanced by each other.

Table 4-8
Transmission and generation investments with changes at Node B (in MW).

	Transmission response	Generation response	Coordinated response
Response to retirement of generation at Node B			
Line A-B (MW)	73	66	77
Line B-C (MW)	53	53	53
Generation at A (MW)	84	85	98
Generation at B (MW)	8	16	10
Generation at C (MW)	1	1	1
Response to demand increase at Node B			
Line A-B (MW)	74	66	80
Line B-C (MW)	53	53	53
Generation at A (MW)	84	85	102
Generation at B (MW)	8	18	10
Generation at C (MW)	1	1	1

Table 4-9
Energy market prices with changes at Node B (in $/MWh).

Period	Node	Transmission response	Generation response	Coordinated response
Response to generation retirement at Node B				
Peak	A	69	64	65
	B	79	78	75
	C	79	79	79
Off Peak	A	28	28	27
	B	28	28	27
	C	28	28	27
Response to demand increase at Node B				
Peak	A	70	64	65
	B	80	79	75
	C	79	79	79
Off Peak	A	29	28	27
	B	29	28	27
	C	29	28	27

Table 4-10
Welfare impacts with changes at Node B (in $billion from Baseline).

	Node	Transmission response	Generation response	Coordinated response
Response to generation retirement at Node B				
Consumers surplus	A	−0.45	0.06	−0.03
	B	2.31	2.62	3.14
	C	9.64	9.90	9.89
Producers surplus	A	1.10	0.27	0.40
	B	−3.17	−3.33	−3.83
	C	−8.86	−8.94	−8.97
Social surplus	All	0.57	0.58	0.60
Response to demand increase at Node B				
Consumers surplus	A	−0.56	0.06	−0.05
	B	5.25	5.68	6.36
	C	9.58	9.89	9.88
Producers surplus	A	1.30	0.27	0.43
	B	−2.10	−2.34	−2.98
	C	−8.83	−8.92	−8.96
Social surplus	All	4.63	4.64	4.68

Table 4-9 displays the energy market prices for each of the six scenarios. We note that the transmission response results in the highest prices in both peak and off-peak periods for all nodes, and the coordinated response tends to have the lowest prices except for node A during the peak period.

Table 4-10 compares the welfare impacts on consumers and producers for the three responses. Overall, the transmission-only response tends to distribute total welfare toward producers and away from consumers. Compared to the coordinated response and the generation response, the transmission-only response reduces consumer's surplus by $1.5–$1.9 billion and $1.1–$1.4 billion, respectively, while increasing the producer's surplus by similar amounts. The coordinated response offers the greatest social surplus for both the consumers and the system because it leverages on the complementarity between transmission and generation.

In summary, we find that the transmission response is neither consumer-friendly nor efficient, generation response is consumer-friendly but inefficient, and the coordinated response is both consumer-friendly and efficient.

5. Merchant transmission

In this section we study merchant transmission investments – as alternatives or complements to regulated investments – in which the coordination of transmission and generation planning relies on a decentralized process of competition with free entry.

In the simple three-node system, we consider scenarios in which merchant projects add transmission capacity between two adjacent nodes, or add both transmission capacity and generation capacity if a generation company participates in the project. The investor in a generation project is assumed to be a company specializing in generation, called a *GenCo*. A transmission project is undertaken by a company specializing in transmission, called a *TransCo*. Merchant investors may be alliances between a TransCo and a GenCo, or between a TransCo and a load-serving Utility in which they share investment costs and subsequent net revenues. A consortium of merchant investors can invest simultaneously in transmission and generation capacity. There are two natural alliances among these companies. For example, a GenCo at node A or a Utility at node B may be willing to share the cost of additional transmission capacity that enables increased exports from the GenCo at A and imports to the utility at B, and perhaps encourages the GenCo to add generation capacity at A.

We examine three scenarios of merchant investment in transmission expansion and compare them with efficient coordination.

1. A transmission project is undertaken by a TransCo, which uses revenues from transmission fees, such as injection charges and/or congestion charges, to recover its costs.
2. A transmission project is undertaken by GenCo A, a local generation company at node A, called Merchant TG-A, which seeks expanded transmission capacity for energy exports.
3. A transmission project is undertaken by the local utility company at node C, called Merchant TU-C, which seeks expanded transmission capacity for energy imports.

In each case the merchant investors incur the full cost of the additional transmission and/or generation capacities.

The efficient plan includes investments in incremental generation capacities at all three nodes and transmission capacities on both lines. It maximizes the social surplus net of investment costs in which the impacts on all market participants are included. For comparison, the investors in merchant projects maximize their own net benefits, without concern for the effects on other market participants. The mathematical formulation of the efficient coordination model and the four merchant investment models are provided in Appendix A.

5.1. Results and discussion

Tables 5-1–5-3 show the results of the three scenarios of merchant transmission in comparison with the efficient plan.

From Table 5-1, the pattern of investments for merchant alliance TU-C differ significantly from those for TransCo and TG-A. Relative to the efficient plan, Merchant TU-C tends over-invest in both transmission (\$1.9–\$2.3 billion) and generation (\$19.7–\$21.2 billion) capacities, while TransCo and Merchant TG-A tend to make smaller transmission investments (\$0.8–\$0.9 billion) but mixed generation investments (\$18.9–\$19.1 billion). The investment pattern of Merchant TU-C reflects the complementarities between transmission and generation from the viewpoint of Utility C as an importer. The investment pattern of the latter group is complicated by the additional motives of TransCo and GenCo to raise energy and congestion revenues.

Table 5-2 shows the effects of the merchant plans on energy market prices, as compared to the efficient plan, at each node. For TransCo and Merchant TG-A, with smaller transmission investments, the nodal energy prices vary with a greater range than those in the efficient plan during peak and off-peak periods. But for Merchant TU-C, the nodal energy prices are uniform as a consequence of increased transmission investments that eliminate transmission congestion.

Table 5-3 shows the effects of the merchant plans on producers and consumers surpluses net of costs, as compared to the efficient plan, at each node.

Table 5-1
Transmission and generation capacity expansion and investments.

Capacity	Line/node	Efficient coordination	TransCo	Merchant TG-A	Merchant TU-C
Transmission (MW)	A-B	66	31	37	108
	B-C	53	25	25	76
	Total	119	56	62	184
Generation (MW)	A	191	151	154	240
	B	189	193	190	181
	C	242	249	241	241
Investment (\$billion)					
Transmission		1.32	0.84	0.90	1.86
Generation		19.11	19.18	18.88	19.71
Total		21.03	20.01	19.78	21.57

Table 5-2
Energy market prices (\$/MWh).

Period	Node	Efficient coordination	TransCo	Merchant TG-A	Merchant TU-C
Peak	A	64	60	63	68
	B	74	76	74	68
	C	79	91	96	68
Off peak	A	27	28	28	25
	B	27	28	28	25
	C	27	30	32	25

Several observations from Table 5-3 for merchant investments are in order:

- TransCo could be financially viable, because as shown in Table 5-3, the net congestion revenue is \$79 million, after netting the transmission investment cost. Relative to the efficient plan, its less expansive transmission plan helps increase the congestion revenue. This strategy lowers the consumer's surplus and raises the producer's surplus in general. However, node A could be an exception, because a constrained transmission capacity of line A-B reduces exports and lowers the local energy prices.
- Merchant TG-A is stable, because compared to TransCo, it increases GenCo A's profit, or the producers surplus at node A, by \$0.35 billion and TransCo's profit, the net congestion revenue, by \$80 million. This suggests that neither would be better off financially by leaving the alliance unilaterally. However, GenCo A may have a weak incentive to initiate the merchant TG-A alliance, because GenCo A is better off with regulated transmission investment under efficient coordination.
- Merchant TU-C benefits from the complementarities between transmission and generation capacities to such a degree that an unconstrained transmission system results. By eliminating nodal price differences, the congestion revenue is zero. To sustain the merchant alliance, an internal transfer payment must be made to cover the entire transmission investment cost incurred by TransCo.
- The results for merchant transmission scenarios are generally consistent with the conventional view that merchant transmission alone could not attain efficient transmission investment. Nonetheless, merchant transmission complement regulated transmission and merchant generation investments with the advantage of strong financial incentives.

6. Sequential coordination

In this section, we study the strategy of sequential coordination between regulated transmission and merchant generation investments. In sequential coordination, transmission and generation investments are planned sequentially. We consider two approaches for regulated transmission investment, called 1) transmission leads generation and 2) transmission follows generation.

Table 5-3
Welfare impacts for merchant transmission (in \$billion from Baseline).

	Node	Efficient coordination	TransCo	Merchant TG-A	Merchant TU-C
Consumers surplus	A	0.05	0.42	0.17	−0.11
	B	3.29	3.05	3.31	4.69
	C	9.92	6.81	5.29	13.27
Producers surplus	A	0.27	−0.19	0.16	0.71
	B	−3.14	−2.78	−3.03	−4.26
	C	−8.98	−6.22	−4.97	−11.33
Congestion revenue		0	0.08	0.16	(1.86)
Social surplus	All	1.41	1.15	1.09	1.11

Table 6-1
Transmission and generation capacity investments.

Capacity		Efficient coordination	Transmission leads generation		Transmission follows generation
			Cournot competition	Transmission merchant	
Transmission (MW)	Line A-B	66	66	31	105
	Line B-C	53	53	25	76
	Total	119	119	56	181
Generation (MW)	Node A	191	153	151	237
	Node B	189	193	193	183
	Node C	242	242	249	241
	Total				
Investment ($billion)					
Transmission		1.32	1.32	0.84	1.84
Generation		19.11	18.88	19.18	19.71
Total		20.43	20.21	20.01	21.54

The first approach comprises two scenarios. In one scenario, we assume that a single transmission merchant chooses optimal investment in the two transmission capacities first, and after this, merchant investors choose generation capacities at the three individual nodes under competitive conditions. Essentially, this scenario is the same as the TransCo scenario in Section 5. In the other scenario, we assume that efficient regulated transmission investment in the two transmission capacities occurs first, and then three oligopolistic merchant investors choose optimal generation investment at each node individually (assuming no new generation capacity at other nodes). The model solves for the Cournot equilibrium among all three generators as they are oligopolies.

For the second approach in which transmission follows generation, we compute optimal generation capacities first on the assumption that there will be no transmission congestion, and then sufficient transmission capacity is provided to eliminate congestion. This scenario is essential the same unconstrained transmission.

Tables 6-1–6-3 summarize the results for these scenarios in comparison with the efficient plan.

In Table 6-1, for the first scenario where transmission leads generation with Cournot competition, the transmission investment is set at the same level as efficient coordination ($1.3 billion). However, Cournot equilibrium yields lower generation investments ($18.9 billion) than the efficient plan ($19.1 billion). In the second scenario with a transmission merchant, the transmission investment is significantly lower ($0.8 billion), while the total generation investment is close to that with Cournot competition. For the third scenario, where transmission follows generation, unfettered competition within an unconstrained transmission network results in greater generation investments ($19.7 billion) complementing a more conservative transmission investments ($1.8 billion).

Table 6-2 shows the effects on energy market prices, as compared to the efficient plan, at each node. When transmission follows generation, there is no transmission congestion, and unfettered competition among all generators in a single market results in uniform energy prices $68/MWh and $25/MWh, respectively, during peak and off-peak periods, yielding zero congestion revenue. When transmission leads generation, Cournot equilibrium among all generators in the three local markets results in higher uniform prices, $79/MWh and $29/MWh, during peak and off-peak periods, respectively, and yields zero congestion rents.[12] When merchant transmission investment leads generation investment, the energy price in the peak period becomes more volatile than in off-peak period.

Table 6-2
Energy market prices ($/MWh).

Period	Node	Efficient coordination	Transmission leads generation		Transmission follows generation
			Cournot competition	Merchant transmission	
Peak	A	64	79	60	68
	B	74	79	76	68
	C	79	79	91	68
Off peak	A	27	29	28	25
	B	27	29	28	25
	C	27	29	30	25

Table 6-3 shows the effects on producers and consumers surpluses net of costs, as compared to the efficient plan, at each node. Two interesting observations from Table 6-3 are in order: Several interesting observations from Table 6-3 are in order:

- Efficient Coordinate dominates all three other scenarios as measured by social surplus. The transmission-follows-generation and Merchant Transmission scenarios yield almost the same level of social surplus ($1.15 billion), while in the former case, the transmission investment ($1.84 billion) is more than two times higher than the latter ($0.84 billion). When transmission follows generation, the transmission system is uncongested. The excess transmission investment is offset by unfettered competition that results in greater generation capacities and lower prices. In short, the transmission-follows-generation strategy fosters generation investments and the resulting competition to benefit consumers.
- In the scenario of transmission-leads-generation with Cournot competition, the total social surplus is lower than those in efficient coordination and transmission-follows-generation. In this scenario consumers are generally left behind to the benefits of producers. These results are driven by the assumption of oligopolistic market power, which is generally known to cause suppressed investments and raise prices. Without local market power, the transmission-leads-generation scenario could be superior to the transmission-follows-generation scenario by saving the excessive transmission investments.[13]
- Efficient Coordinate dominates all three other scenarios as measured by social surplus. The transmission-follows-generation and Merchant Transmission scenarios yield almost the same level of social surplus ($1.15 billion), while in the former case, the transmission investment ($1.84 billion) is more than two times higher than the latter ($0.84 billion). When transmission follows generation, the transmission system is uncongested. The excess transmission investment is offset by unfettered competition that results in greater generation capacities and lower prices. In short, the transmission-follows-generation strategy fosters generation investments and the resulting competition to benefit consumers.

[12] This observation resembles the result obtained by David Kreps and Jose Scheinkman (1983), where two-stage competition in which initial capacity commitments are followed by competitive pricing in the energy market yields the same outcome as one-stage Cournot competition.

[13] See Pozo, Contreras, and Sauma (2013, 2017).

Table 6-3
Welfare impacts of sequential coordination (in $billion from Baseline).

	Node	Efficient coordination	Transmission leads generation		Transmission follows generation
			Cournot competition	Merchant transmission	
Consumers surplus	A	0.05	−1.11	0.42	−0.09
	B	3.29	2.09	3.05	4.23
	C	9.92	8.62	6.81	11.95
Producers surplus	A	0.27	2.36	−0.19	0.68
	B	−3.14	−2.14	−2.78	−4.27
	C	−8.98	−8.74	−6.22	−11.35
Social surplus	All	1.41	1.09	1.15	1.15

- In the scenario of transmission-leads-generation with Cournot competition, the total social surplus is lower than those in merchant transmission and transmission-follows-generation. In this scenario consumers are generally left behind to the benefits of producers. These results are driven by the assumption of oligopolistic market power, which is generally known to cause suppressed investments and raise prices. In the absence of local market power, the transmission-leads-generation scenario could be superior to the transmission-follows-generation scenario by saving the excessive transmission investments. However, Cournot competition may lead to the possibility of multiple equilibria, and in extreme cases, an equilibrium outcome could be worse than no investment at all.[14] As the worst-case scenario, anticipative expansion may be even worse than the status quo.

The stochastic optimization model results could be fairly sensitive to certain input parameters and may not be robust against all possible uncertainties in the future. In particular, the merchant investments outcome may be quite different than the one projected by the transmission planner. Moreover, transmission investments are highly irreversible and the economic tradeoff between robustness and flexibility predicts risk premium for waiting based on option value enhancement. Transmission planning requires ongoing learning. For instance, while waiting is costly in that there is reliability risk or a cost incurred from an expensive option, too early a decision to add transmission capacity may deprive valuable learning opportunities and leave one with unused transmission capacity. Emerging technological and market changes have increased the importance of further research on stochastic optimization within a multistage dynamic planning framework.

7. Concluding remarks

There are two parts of the study reported here. One part proposes an integrated framework for developing plans that promote efficient coordination of generation and transmission investments. Within a liberalized market system with merchant investors, an RTO's planning process can benefit from studying many different scenarios. The examples in this paper illustrate substantial differences among efficient regulated plans and those preferred by various merchant investors and other stakeholders. An RTO's consultations with stakeholders and regulators is better informed if it anticipates the implications of a variety of project designs – such as efficient or merchant-preferred capacity magnitudes, and the resulting energy prices and distribution of welfare impacts among energy market participants. The latter implications are especially germane when addressing rules for sharing costs of regulated projects, since quantified estimates are necessary for rules based on the principle of beneficiaries-pay.

The second part is the mathematical model. Using standard optimization software, it can be applied to estimate some consequences of specific proposals for generation or transmission investments, such as the distributions of nodal prices and welfare impacts. Or it can be used to identify an efficient plan of investments, or plans that maximize the net benefits of various merchant investors or alliances among them.

A valuable attribute of the model is its formulation as a two-stage stochastic optimization problem subject to constraints. This feature enables comparisons such as between an efficient plan requiring cost recovery from stakeholders, and plans that are constrained to be self-financed via injection fees and congestion charges. When the efficiency loss from a self-financed plan is small, there can be compensating advantages from averting struggles over cost allocation. Interestingly, a Boiteux-Ramsey cost sharing rule produces energy prices and social welfare impacts that appear essentially indistinguishable from those obtained under efficient coordination. In addition, we envision that the methodology could facilitate forward market mechanisms that enable efficient coordination of transmission and generation investments when non-convexities (e.g., economies of scale and lumpiness) become a less prohibitive barrier to efficient pricing mechanism.[15]

We also see the integrated economic framework and the simple basic model as useful in studies of basic conceptual issues. Two such issues illustrated in this paper arise from the separation between regulated and merchant investments in liberalized market systems. One is the choice between transmission and generation solutions to local problems, and another is the choice of which sequence of transmission and generation investments to implement when these investments cannot be coordinated simultaneously. In the version described in this paper, the model is simplified, for instance, by assuming constant price elasticities of supply and demand, and constant marginal costs of generation and transmission capacities. In some practical situations this simplification is sufficient if the model is calibrated to market data. In more complex situations, the simple model may be calibrated to more complex economic for analyzing the effects of prices, incentives and welfare. To support coordination through new forward market mechanisms, it would be necessary to work with an expanded model allowing more detailed specifications and to work directly with market and engineering data.

CRediT authorship contribution statement

Hung-po Chao: Conceptualization, Writing - original draft, Writing - review & editing, Methodology, Formal analysis, Software. **Robert Wilson:** Conceptualization, Writing - original draft, Writing - review & editing.

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Appendix A. Mathematical formulation

In this appendix, we provide the mathematical formulation of the simple basic model in Section 3 for the scenarios in Sections 4–6. For our purposes, we consider a three-node network with a tree structure, A-B-C ($N = \{A, B, C\}$, where the hub at node B is located at the center linking to A in the north and C in the south. Further, we shall ignore transmission losses. Under these assumptions, we need not worry

[14] See Pozo, Contreras, and Sauma (2013, 2017).

[15] See Chao (2015) and Chao (2019).

about the complexities associated with the physical laws and loop-flows in an AC power network. (Chao and Peck, 1996) Replacing the consumption and production levels by the demand and supply functions, we can restate the basic model in (1) – (7) equivalently as follows,

$$\underset{(\boldsymbol{p},\boldsymbol{\theta},\boldsymbol{Y},\boldsymbol{Z})}{\text{Max}}\ E\left[\sum_{n\in N}\sum_{t=1}^{T}\boldsymbol{B}_{nt}(\boldsymbol{D}_{nt}(\boldsymbol{p}_{nt}))-\boldsymbol{C}_{nt}(\boldsymbol{S}_{nt}(\boldsymbol{p}_{nt},Y_n),Y_n)\right]-\sum_{n\in N}k_nY_n-\sum_{i,j\in N}I_{ij}(Z_{ij}) \tag{A1}$$

subject to

$$\boldsymbol{S}_{it}(\boldsymbol{p}_{it},Y_i)-\boldsymbol{D}_{it}(\boldsymbol{p}_{it})=\sum_{j\in N}\boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i}-\boldsymbol{\theta_j}),\text{for } i\in N;t=1,\dots,T \tag{A2}$$

$$\boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i}-\boldsymbol{\theta_j})\le Z_{ij},\textit{for } i,j\in N;t=1,\dots,T \tag{A3}$$

and equilibrium conditions,

$$\nabla\boldsymbol{B}_{nt}(\boldsymbol{D}_{nt}(\boldsymbol{p}^*_{nt}))=\nabla_{\boldsymbol{x}}\boldsymbol{C}_{nt}(\boldsymbol{S}_{nt}(\boldsymbol{p}^*_{nt},Y^*_n),Y^*_n)=\boldsymbol{p}^*_{nt} \tag{A4}$$

$$\boldsymbol{p}^*_{nt}=\boldsymbol{p}^*_{0t}+\sum\nolimits_{i=1}^{N}\sum\nolimits_{j=1}^{N}\mu^*_{ij}\beta^n_{ij},\textit{ and }\mu^*_{ij}\left[\boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i}-\boldsymbol{\theta_j})-Z^*_{ij}\right]=0 \tag{A5}$$

Under the assumption that the gross consumer benefit functions are concave and the generation cost functions are convex, the simple model solves the central problem of transmission and generation planning, and the optimal solution can be implemented through centralized coordination between merchant generation investments and regulated transmission investments. This plan supports the merchant investments in generation capacity because market revenues should be sufficient to recover the investment costs. However, transmission projects typically have large fixed costs with significant economies of scale, and transmission revenues are often insufficient to recover the fixed costs. The revenue deficiency issue, also known as the missing money problem, remains an open issue. We consider two ways to address this issue: 1) Boiteux-Ramsey plan and 2) merchant transmission investments.

A.1. Boiteux-Ramsey plan

We consider a cost recovery mechanism based on a two-part second-best pricing proposal, called Boiteux-Ramsey plan.[16] The two-part pricing plan also maximizes the social surplus, but subject to the constraint that transmission costs are fully recovered from transmission congestion revenues with additional revenue is obtained from injection charges.

$$\underset{(\boldsymbol{p},\boldsymbol{\theta},\boldsymbol{Y},\boldsymbol{Z})}{\text{Max}}\ E\left[\sum_{n\in N}\sum_{t=1}^{T}\boldsymbol{B}_{nt}\left(\boldsymbol{D}_{nt}\left(p^d_{nt}\right)\right)-\boldsymbol{C}_{nt}(\boldsymbol{S}_{nt}(p^s_{nt},Y_n),Y_n)\right]-\sum_{n\in N}k_nY_n-\sum_{i,j\in N}I_{ij}(Z_{ij}) \tag{A6}$$

subject to

$$\boldsymbol{S}_{it}(p^s_{nt},Y_i)-\boldsymbol{D}_{it}\left(p^d_{nt}\right)=\sum_{j\in N}\boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i}-\boldsymbol{\theta_j}),\text{for } i\in N;t=1,\dots,T \tag{A7}$$

$$\boldsymbol{\Psi}_{ij}(\boldsymbol{\theta_i}-\boldsymbol{\theta_j})\le Z_{ij},\textit{for } i,j=1\in N;t=1,\dots,T \tag{A8}$$

$$\sum_{n\in N}\sum_{t=1}^{T}p^d_{nt}D_{nt}\left(p^d_{nt}\right)-p^s_{nt}S_{nt}(p^s_{nt},Y_n)\ge\sum_{i,j\in N}I_{ij}(Z_{ij}) \tag{A9}$$

Conditions (A6)–(A9) indicate that the Boiteux-Ramsey plan permits two prices rather than one at each node, p^d and p^s. The difference between the two prices, $p^d - p^s$, represents the injection charge at that node.

A.2. Merchant transmission investment

Merchant transmission investment offers two advantages. It not only obviates the burden of a separate cost allocation mechanism but also permits a decentralized approach to transmission and generation planning. However, the effectiveness of merchant investment depends on how well it can align merchant incentives in ways that complement the planner's social welfare objective.

We consider three possible types of merchants: 1) a pure transmission merchant, TransCo, 2) a generation and transmission merchant, GenCo A and TransCo, and 3) a utility and transmission merchant, Utility C and TransCo. The interactions between a merchant and other market participants are modeled as the principal-agent relationship between a dominant firm and the competitive fringe. In the following, the basic model is modified with a new objective function that appropriately reflects the merchant's incentives and additional constraints that reflect the competitive equilibrium conditions for all non-merchant participants. In all cases, Conditions (A2)–(A5) remain applicable.

A.3. TransCo

$$\underset{(\boldsymbol{p},\boldsymbol{\theta},\boldsymbol{Y},\boldsymbol{Z})}{\text{Max}}\ E\left[\sum_{n\in N}\sum_{t=1}^{T}\boldsymbol{p}_{nt}\boldsymbol{D}_{nt}(\boldsymbol{p}_{nt})-\boldsymbol{p}_{nt}\boldsymbol{S}_{nt}(\boldsymbol{p}_{nt},Y_n)\right]-\sum_{i,j=1}^{N}I_{ij}(Z_{ij}) \tag{A10}$$

subject to Eqs. (A2)–(A5) and

$$E\left\{\sum_{t=1}^{T}\left[\frac{\partial\boldsymbol{C}_{nt}(\boldsymbol{S}_{nt}(p_{nt},Y_n),Y_n)}{\partial Y_n}\right]\right\}+k_n=0,\text{for } n\in N \tag{A11}$$

Expression (A10) is the profit for a pure merchant transmission company. Eq. (A11) represents the efficient investment conditions for merchant generators in a competitive equilibrium.

A.4. GenCo A & TransCo

$$\underset{(\boldsymbol{p},\boldsymbol{\theta},\boldsymbol{Y},\boldsymbol{Z})}{\text{Max}}\ E\left[\sum_{t=1}^{T}\boldsymbol{p}_{At}\boldsymbol{S}_{At}(\boldsymbol{p}_{At},Y_A)-\boldsymbol{C}_{At}(\boldsymbol{S}_{At}(p^s_{At},Y_A),Y_A)\right]-k_AY_A$$

$$+E\left[\sum_{n\in N}\sum_{t=1}^{T}\boldsymbol{p}_{nt}\boldsymbol{D}_{nt}(\boldsymbol{p}_{nt})-\boldsymbol{p}_{nt}\boldsymbol{S}_{nt}(\boldsymbol{p}_{nt},Y_n)\right]-\sum_{i,j\in N}I_{ij}(Z_{ij}) \tag{A12}$$

subject to Eqs. (A2)–(A5) and

$$E\left\{\sum_{t=1}^{T}\left[\frac{\partial\boldsymbol{C}_{nt}(\boldsymbol{S}_{nt}(p_{nt},Y_n),Y_n)}{\partial Y_n}\right]\right\}+k_n=0,\text{for } n\neq A,n\in N \tag{A13}$$

In comparison with the case with a pure transmission merchant, GenCo A's profit is added to the objective function (Eq. (A12)) while the competitive investment condition for the generator is excluded from (A13).

[16] This cost recovery mechanism derives from proposals by Marcel Boiteux (1956) and Frank Ramsey (1927).

A.5. Utility C and TransCo

$$\begin{aligned}&\underset{(\boldsymbol{p},\boldsymbol{\theta},\boldsymbol{Y},\boldsymbol{Z})}{\text{Max}}\ E\left[\sum_{t=1}^{T}\boldsymbol{B}_{Ct}(\boldsymbol{D}_{Ct}(\boldsymbol{p}_{Ct}))-\boldsymbol{p}_{Ct}\boldsymbol{D}_{Ct}(\boldsymbol{p}_{Ct})\right]\\&+E\left[\sum_{n\in N}\sum_{t=1}^{T}\boldsymbol{p}_{nt}\boldsymbol{D}_{nt}(\boldsymbol{p}_{nt})-\boldsymbol{p}_{nt}\boldsymbol{S}_{nt}(\boldsymbol{p}_{nt},Y_n)\right]-\sum_{i,j\in N}I_{ij}(Z_{ij})\end{aligned} \tag{A14}$$

subject to Eqs. (A2)–(A5) and Eq. (A11)

This scenario differs from the case of TransCo only in the objective function (Eq. (A14)).

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