Preliminary Draft

Coordination of Electricity Transmission and Generation Investments

An Economic Analysis of Strategies, Incentives and Welfare Impacts

Hung-po Chao and Robert Wilson[1]

ISO New England and Stanford University

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Abstract

Before wholesale electricity markets were liberalized in the 1990s, a vertically integrated utility coordinated its investments in transmission and generation capacities. Now, a regulated regional transmission organization (RTO) manages the infrastructure of transmission and energy markets. An RTO plans most transmission projects, while commercial firms choose generation investments on a for-profit merchant basis. Nevertheless, the benefits from coordinating transmission and generation investments remain, so it is important for an RTO's planning process to recognize the role of merchant investments. This includes anticipating merchant generation capacity, comparing regulated and merchant transmission projects, and comparing transmission and generation solutions to specific problems.

These aspects of transmission planning require new tools. An RTO needs to anticipate the incentives for merchant investments, and to estimate the impacts of merchant and regulated projects on energy prices and thus on the welfare of participants in wholesale energy markets. Because the time frame of transmission planning is much longer than for generation, such models are necessary to enable efficient coordination of regulated transmission projects with anticipated or alternative merchant projects. And, estimates of price and welfare impacts are useful because a regulated transmission project and its cost allocation must be approved by stakeholders.

Here we propose an economic framework as an adjunct for planning and evaluating transmission projects. Its distinctive features are explicit modeling of incentives for merchant investments in generation and transmission capacities, and for each project, explicit modeling of price and

[1] The views in this paper are those of the authors and do not necessarily reflect the positions of the ISO/RTO New England or other organizations. Email addresses: hchao@iso-ne.com and rwilson@stanford.edu.

welfare impacts on suppliers and demanders at each node in the transmission network. Assuming that wholesale energy markets are competitive, a single all-purpose model encompasses incentive, price, and welfare effects. The parameters of the model can be calibrated from price elasticities of supply and demand at each node estimated from observed data in wholesale markets, and from direct estimates of the costs of generation and transmission capacity. Thus calibrated, the model enables an RTO to study many different scenarios of merchant and regulated investments in transmission, and merchant investments in generation.

To illustrate applications of the general model, in this paper we apply it to a simple system with three nodes and two transmission lines, and a load-duration profile having only a peak and an off-peak period with the peak period coinciding at the three nodes. The model starts from an initial configuration of existing capacities. Then the effects of each scenario are predicted using constant-elasticity demand and supply functions at each node in each period, and linear cost functions for new transmission and generation capacities. We use price elasticities and capacity costs that are merely illustrative rather than estimated from data as in realistic applications.

The scenarios compared span the extremes from a comprehensive investment plan that is efficient overall, to merchant investments in generation and/or transmission. Other scenarios examine how the sequencing of transmission and generation investments affects outcomes.

Scenarios with regulated transmission examine a first-best efficient plan for both transmission and generation capacities. The allocation among demanders of net cost recovery is based on either the loads served or the resulting incremental benefits as measured by consumer surpluses. We also examine two second-best efficient plans in which the design is subject to the further constraint that revenue from injection charges and/or nodal price differences must recover transmission costs. The scenarios studied indicate that the efficiency loss from a self-financed plan can be small and might be compensated by avoiding the need to allocate cost recovery among participants in the energy market.

For scenarios with merchant investment, the model predicts the transmission capacities preferred by a transmission company, by any generator, by any load-serving utility, and by several natural alliances among these parties. The model also predicts the generation capacities preferred by merchant investors at any one node, or at any set of nodes by invoking the Cournot model of competition among generators. To examine the role of sequencing, the scenarios studied include the case that generation investments depend on prior investments in transmission capacities; and the alternative case that, subsequent to generation investments, sufficient transmission capacity to relieve congestion is provided.

In all these scenarios, the numerical results predict substantial welfare impacts on the various market participants, both positive and negative, and in some cases the magnitudes are comparable to the cost of the transmission capacity. We observe substantial incentives for merchant investments in transmission, mainly because merchant investors need not take account of adverse impacts on other market participants that an efficient plan considers. We also find that competition among generators is more efficient when they are not constrained by transmission capacity, because there is more dilution of market power. These and other qualitative conclusions are described in more detail in the text.

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1. Introduction and Overview

In a wholesale electricity system, two essential elements are capacities for generation and transmission. Investments in these capacities are basic determinants of performance. Such decisions were centralized in vertically integrated systems, but modern liberalized market-based systems have limited means of coordinating investments in generation capacity and transmission capacity. Coordination of generation and transmission investments is a persistent problem in liberalized systems. Generation and some transmission investments are made by commercial firms on a merchant basis. In the United States, other transmission investments on a regulated basis are proposed 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.[2]

In this paper we propose a framework, supported by a mathematical model, for studying policy issues that confront an RTO. The model serves as a computational tool for identifying some of the main effects of alternative investment strategies, such as differences in generation and transmission capacities resulting from merchant and regulated investments, and differences in energy prices and the resulting distributions of welfare impacts among market participants. Thus it offers a high-level perspective on major features – although necessarily it does not address the fine details of specific investment proposals.

Issues Addressed

In this subsection we introduce the main issues addressed by studies of various scenarios that are reported in Sections 3, 4, and 5.

It is always true that an RTO must assure the security and reliability of the transmission system, and provide competitive wholesale energy markets that can meet demands at reasonable prices. Beyond these fundamental requirements, there are several basic issues of coordination that affect planned responses to changes in demand and supply, the roles of merchant and regulated investments, and sequencing of transmission and generation investments. We outline these issues in the next subsections.

[2] In the U.S., essentially all transmission investments and operations are subject to approvals by the Federal Energy Regulatory Commission (FERC). Each RTO or 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 RTOs or ISOs also conduct auction markets for generation capacity sufficient to ensure transmission reliability. Some regional systems are not managed by RTOs.

Responses to Changes in System Capacities and Loads

Transmission and generation planning respond to system changes in both the short and long term. The first issue, addressed here in Section 3, 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.[3] Moreover, the model can calculate the response that maximizes total 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.

The magnitudes of an 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

[3] Producers 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. Consumers 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.

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.

Incentives for Merchant and Regulated Investments in Transmission Capacity

Transmission planning may include both regulated and merchant investments. The second issue, addressed here in Section 4, is:

- How can an RTO compare merchant investment in transmission with regulated investment? A passive option is to propose regulated 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 – as well as a consortium composed of any group of these. 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 for comparisons, we often use the "first-best" efficient capacities that are chosen to maximize the total among all market participants of producers and consumers 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 consumer surplus. Two "second-best" efficient versions use particular rules. In one version the investment cost must be recovered by congestion charges, and in the other it must be 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.

Sequencing of Investments in Generation and Transmission Capacities

Transmission and generation investments usually take place at different times. The third issue, addressed in Section 5, 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 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.

In the next section we set forth the basic assumptions that underlie the analytical framework and the formulation of the model.

Section 2 – Methodology

In this section, we describe the basic features of the policy framework, and the flexible analytical model that supports it. The model can be used to study various scenarios of coordination of transmission and generation capacity planning in competitive wholesale electricity markets. It also serves as a computational tool for identifying some of the main quantitative 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 main focus is on investments whose consequences are primarily economic, such as effects on the pattern of prices among the nodes in the network.

For illustrative purposes here, we assume throughout that the transmission network has a tree structure, and system reliability considerations and reserve requirements are not explicitly modeled. The model can be extended to incorporate externality effects of loop flows in a general network, as described in Appendix A.

2.1 Basic Features of the Policy Framework

Coordination of generation and transmission investments is a persistent problem in liberalized systems. Traditionally, such decisions were centralized in vertically integrated systems, but modern liberalized market-based systems have limited means of coordinating investments in generation capacity and transmission capacity. Joskow and Schmalensee (1983) offer a policy framework for evaluating alternative deregulation proposals, and point out:

"Transmission plays the most fundamental role in achieving the economies of electric power supply that modern technology makes possible. ... Decisions at any point in a power system affect costs everywhere in the system. These effects raise potential externality problems. ... Vertical and horizontal integration can mitigate these problems by reducing the number of firms involved, and cooperative activities between independent firms (and area-wide systems) currently provide important mechanisms for dealing with potential externality problems. Whether adequate mechanisms would emerge in power systems with less centralized ownership than we observe is a fundamental research question. It must be answered in order to evaluate reliably deregulation proposals."

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.[4]

[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/or independent system

In the following, we describe the coordination problems 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 Transmission Planning and Coordination

Three conundrums of transmission planning in coordination with merchant generation investments are:

1) which goes first, generation or transmission?
2) which should it be, generation or transmission? and
3) how might regulated projects be financed?

In the following, we highlight key considerations concerning the timing, nature and financing of investment decisions.

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.

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 and 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.

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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.

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.

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.

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, and actually the injection charge is akin to sharing in proportion to load served. 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 constrained optimization problem. 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 self-financing.

2.3 Role of Merchant Investment in Transmission

A liberalized market-based system depends on merchant investments in generation capacity, and also allows merchant investment in transmission capacity. Integrating merchant transmission into transmission planning poses several basic 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 Section 4. 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 Processes

A transmission project must be approved by regulatory agencies, and if more than plan is proposed then they choose one. We do not attempt here to model regulatory processes, but 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 energy flows, 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 differing views. 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. A second party includes the demanders at the export node and the suppliers at the import node, since they stand to lose. These two parties 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.

2.5 Basic Scenarios for Coordination Policy

In this report, we consider policy scenarios that address three basic problem areas: efficient coordination, merchant investments, and sequential coordination.

Efficient Coordination

In Section 3, we study the efficient coordination scenario and compare it with scenarios of zero and unconstrained transmission capacities, and later use it as a benchmark for comparing other scenarios. Efficient coordination aims to ensure that transmission and generation investments are planned together like in a vertically integrated utility to maximize total surplus, i.e. the sum of producers and consumers surpluses among all market participants net of investment costs. This scenario involves only regulated transmission projects undertaken to provide beneficial infrastructure, perhaps because it has not attracted merchant investors because revenues would not recover investment costs.

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 common-sense approaches such as in proportion to load served, or in proportion to incremental benefits (consistent with the beneficiaries-pay principle). The distributional impact of a regulated project is especially 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 and lowers prices for suppliers at B. Such a cost sharing rule affects the distribution of total surplus among participants but not the overall efficiency.

Then, we consider two alternative approaches for recovering the costs of regulated transmission projects, called *constrained efficient* or second-best plans, without using a separate cost sharing rule. These scenarios are also designed to maximize total surplus, but subject to the constraint that revenues from the project suffice to recover costs. The first version, called Ramsey-Boiteux I, assumes that the only revenue is from congestion charges, whereas the second version, called Ramsey-Boiteux II, assumes that there is also revenue from an injection charge.[5]

Merchant Investments

In Section 4, we study coordination through merchant investments. Merchant investments depend on a decentralized process in which transmission and generation investments are guided by the private incentives of for-profit firms. 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

[5] These cost sharing alternatives are derived from the Ramsey-Boiteux pricing 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. Marcel 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.

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 producers and consumers 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.

Sequential Coordination

In Section 5, as a long-term planning strategy, we consider sequential coordination in which transmission and generation investments are decided in sequence. 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.[6] 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 merchant investments are proposed.[7]

Here we study two scenarios.

- In the first scenario, efficient 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. 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 simultaneously.
- In the second scenario, optimal generation capacities are computed first on the assumption that there will be no transmission congestion, and then sufficient transmission

[6] This view is encouraged by the longer times for planning and building transmission lines, and their longer useful lives, compared to generation capacity. The present model does not address this aspect.
[7] 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.

capacity is provided to eliminate congestion. This is done for each line A-B and B-C separately and the affected GenCos, and also for both lines simultaneously and all three GenCos at nodes A, B, and C.

2.6 Basic Features of the Analytical Model

Next we describe the technical and economic features of the model that is used to study the various policy scenarios of coordination.

Stationary Environment

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. As described later, the model first establishes a status quo based on embedded capacities, and then evaluates investment projects as increments to the status quo.

We allow for two periods with differing demands, called the peak and off-peak periods.[8] These periods are assumed to be synchronous, i.e. peak periods occur simultaneously for all nodes. 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, interpreted as half of each year.

Competitive Wholesale Markets

Generation companies are not regulated – each participates in the ISO's energy markets on a merchant basis. However, the model assumes that wholesale energy markets are competitive; specifically, the energy price at a node is modeled as always the same as the local 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 GenCos at different nodes adding capacity simultaneously.

Measurement of Welfare Effects

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 *producers surplus*, which is just the gross profit 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 *consumers 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.

[8] The model is easily expandable to allow multiple periods representing segments of the load-duration curve.

We caution that using *total surplus* – the sum of producers' and consumers' surplus – to measure the aggregate benefit of a project, and to verify whether the overall design of a project is efficient, 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. Because there is no guarantee that this favorable outcome will occur, the model includes an option to use the Shapley value to 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.

Formulation of the Basic Model

In the basic model, we assume a simplified network configuration with three nodes in a tree structure, designated A – B – C, or $N = \{A, B, C\}$, where node B is designated as the hub located between A and C.[9] We ignore transmission losses. Investments in transmission capacity are allowed only between nodes A and B and between B and C.

We consider a two-stage decision model in which the planner decides on new investments in transmission and generation capacities before electricity demands, supplies, and prices as well as power flows on the electric network are determined. The planner's objective is to maximize the total surplus, the sum of consumers surplus and producers surplus.

We consider two periods, peak and off-peak periods, denoted by 1 and 2 respectively, or by $t \in T = \{1,2\}$. 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.[10] 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 cost I(K) as a function of transmission capacity (K) is

$$I(K) = f + v \times K,$$

where *f* and *v* denote fixed and 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

[9] The model is expandable to allow more than three nodes in a tree structure.
[10] Our previous paper (Economic Analyses of Distributional Impacts of Transmission Projects, November 2011) assumed linear demand and supply functions.

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

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 Z^{δ} affecting the demanded quantity is fixed throughout, whereas 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 are estimated from existing market data, although typically one would use a more detailed load-duration curve and thus allow for more than the two periods used here for peak and off-peak demand conditions. For relatively small changes from the status quo, the price elasticities are estimated 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.[11]

Here, however, our purpose is limited to illustrating how the model can be used to examine policy issues such as those outlined above. Therefore we posit a particular status quo 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,

$$B_n(q_{n1}, q_{n2}, Z_n) = \sum_{t \in T}\left[\left(\frac{1}{1-\varepsilon}\right)\left(a_{nt}\hat{p}^{1-\varepsilon} - \varepsilon a_{nt}^{\frac{1}{\varepsilon}} Z_n^{\frac{-\delta}{\varepsilon}} q_{nt}^{1-\frac{1}{\varepsilon}}\right)\right], \text{ and}$$

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

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

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

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

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

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

$$D_{nt}(p,Z_n) = \beta_{nt}^{-1}(p) = a_{nt} Z_n^{-\delta} p^{-\varepsilon}, \text{ and}$$

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

For the illustrations here, we assume that the status quo is the first-best efficient plan and $\delta = 0$. Thus 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 status quo's generation and transmission capacities are taken as embedded capacities that are free and it is only new capacities that incur costs.

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 total surplus of all market participants net of investment costs. 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.

Let Y_n be the generation capacity at node *n*, and K_{nB} the transmission capacity between node *n*, which could be *A or C,* and node *B*, at the central hub. Then the maximization problem is

$$\underset{(K_{nB},Y_n,p_n)}{Max} \sum_{n \in N} \sum_{t \in T} B_{nt}\big(D_{nt}(p_{nt})\big) - C_{nt}\big(S_{nt}(p_{nt},Y_n),Y_n\big) - \sum_{n \in N} k_n Y_n - \sum_{n \in N} (v_{nB} K_{nB} + f_{nB}) \qquad (1)$$

subject to

$$\sum_{n \in N} \big[S_{nt}(p_{nt},Y_n) - D_{nt}(p_{nt})\big] = 0, \text{ for } t \in T. \qquad (2)$$

$$\big|S_{nt}(p_{nt},Y_n) - D_{nt}(p_{nt})\big| \le K_{nB}, \text{ for } n \in \{A,C\}, \ t \in T. \qquad (3)$$

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 comprehensive mathematical formulation that includes each of the scenarios studied here.

Figure 1 illustrates the market trading and power flows between two nodes A and B.

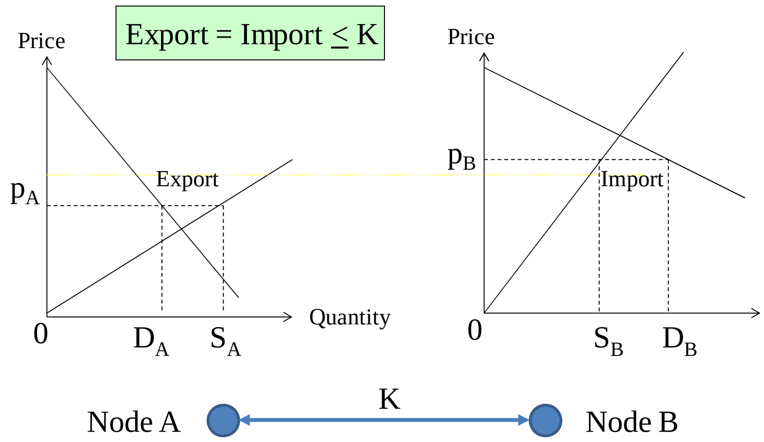

Figure 2-1 – Market Trading and Power Flows between Two Nodes

Model Parameters for All Scenarios

In Tables 2-1 and 2-2, 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.

Table 2-1 – Demand and Supply Parameters

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

Table 2-2 – Transmission Cost Parameters

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

Here are some immediate observations.

- At each node, the demand scale factor is twice as high in the peak period as in the off-peak period. Thus, if all nodes have the same energy price, then total demand 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 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 status quo establishes the embedded generation capacities, and the resulting nodal prices of energy based on the above specification of elasticities and cost parameters. Recall that in the scenarios studied in the next sections the generation capacities embedded in the status quo are available at no cost.

Section 3 – 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 jointly set in an efficient fashion to maximize the total surplus, i.e. the sum of producers and consumers surpluses net of 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 status quo and an uncongested transmission system, how it recovers investment costs, and how it responds to changes in the system.

3.1 Comparison with Status Quo and Uncongested Transmission System

In this subsection, we compare efficient coordination with two extreme scenarios – a generation-only system with no transmission, and a generation system within an uncongested 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 initial Status Quo 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 Status Quo. Uncongested Transmission represents an optimal generation expansion plan from the Status Quo obtained with sufficient transmission capacities so that there is no congestion. Table 3-1 compares the results for efficient coordination with those for the two extreme scenarios, Status Quo and Uncongested Transmission.

Table 3-1 – Transmission and Generation Capacity Investments

		Status Quo	Efficient Coordination	Uncongested Transmission
Transmission Capacity (MW)	Line A-B	0	66	105
	Line B-C	0	53	76
Generation Capacity (MW)	Node A	106	191	237
	Node B	181	189	183
	Node C	241	242	241
Transmission Investment ($Million)		-	1,324	1,837
Generation Investment ($Million)		-	19,111	19,706
Total Investment ($Million)		-	20,434	21,542

As shown in Table 3-1, the efficient plan adds in total 119 MW of transmission capacity at $1.3 billion and 93 MW of generation capacity at $19.1 billion. In comparison, the uncongested transmission system adds in total 118 MW of transmission capacity and 133 MW of generation capacity, which are respectively 52% and 43% 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 total investment is increased modestly by 5%, as the incremental transmission investments make it possible to shift generation from nodes B and C to node A by increasing the investment in the most efficient technology.

Table 3-2 shows the competitive energy prices in market equilibrium for the three scenarios. In the initial Status Quo, the nodal energy prices vary all over the system during both peak and off-peak periods. On the other hand, with uncongested transmission, the nodal prices are uniform. The efficient plan represents a hybrid of these extreme cases. 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.

Table 3-2 – Energy Market Prices (in $/MWh)

Period	Node	Status Quo	Efficient Coordination	Uncongested Transmission
Peak	A	67	64	68
	B	91	74	68
	C	112	79	68
Off Peak	A	25	27	25
	B	34	27	25
	C	42	27	25

In general, nodal prices are affected by local market conditions. In Status Quo, for instance, the price at node A is the lowest because it has the lowest-cost supply technology and the lowest demand, 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 uncongested 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, without transmission in the Status Quo. The efficient plan eliminates congestion only during the off-peak period, resulting in a uniform price. During the peak period, however, the nodal price differences remain, though less pronounced than in Status Quo, and the congestion costs reflect the transmission investment costs. For illustration, 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. Indeed, with an efficient plan, the peak-period marginal congestion cost equals the marginal cost of transmission capacity.

Table 3-3 shows the distribution of consumers and producers surpluses, net of investment costs. As expected, the efficient plan yields the highest social surplus, $123,923 million, compared to $122,514 million for the status quo and $123,667 for the uncongested transmission system. Therefore, relative to the Status Quo, the gain in total surplus from uncongested transmission is $1.15 billion, and that from the efficient plan is $1.41 billion, for a benefit-cost ratio of 1.6 and 2.1, respectively.

Table 3-3 – Distribution of Consumers and Producers Surpluses ($million)

	Node	Status Quo	Efficient Coordination	Uncongested Transmission
Consumers Surplus	A	17,134	17,183	16,730
	B	29,359	32,653	33,460
	C	37,800	47,722	50,191
	All	84,293	97,559	100,381
Producers Surplus	A	4,725	4,990	5,404
	B	12,068	8,924	7,803
	C	21,429	12,451	10,079
	All	38,221	26,365	23,286
Social surplus	All	122,514	123,923	123,667

Despite the overall efficiency gains, there are gains and losses among individual participants. As a group, consumers benefit from greater competition and transmission expansion because they gain broader access to low cost supplies, but on the other side, producers tend to lose. As shown in Table 3-3, with the efficient plan, consumers gain $13.3 billion in total surplus (from $84.3 billion to $97.6 billion); and with uncongested transmission, they gain an even greater amount of $16.1 billion. On the other hand, the total surplus for producers is reduced by $11.9 billion (from $38.2 billion to $26.3 billion) and $14.9 billion, respectively, with efficient coordination and uncongested transmission. This suggests why generators tend to resist policies that promote transmission expansion and market liberalization.

On a more granular level, transmission expansion promotes market trading between regions in ways that tend to lower the price in an import region but raise the price in an export region. As a consequence, 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. Table 3-3 shows that even though consumers as a group gain from uncongested transmission, the consumers surplus at node A (an export region) drops by $404 million. On the other hand, the producers at node A gain $265 million (from $4,725 to $4,990) and $679 million, respectively, with efficient coordination and uncongested transmission. This suggests why consumers in low cost regions tend to resist policies that promote market liberation and inter-regional transmission, leading to often contentious policy debates about cost sharing rules.

3.2 Cost Sharing Rules

In this subsection, we consider the cost sharing rule to recover the regulated transmission investments including both administrative and market-based approaches. We start with two alternative administrative methods, called load sharing and beneficiaries pay. We assume that they mainly affect the distribution of welfare among participants but not the overall efficiency.

Table 3-4 shows the results under the two methods for recovering the fixed transmission cost of $400 million. As a simple way to share cost equitably, the load sharing method allocates the fixed transmission cost to consumers in proportion to their demands. A refined approach, the beneficiaries-pay method, allocates the cost to consumers in proportion to their net benefits, as measured by the increase in the consumers surplus, relative to the Status Quo. Compared to the load sharing method, the beneficiaries-pay method reduces the cost burden for consumers at nodes A from 17% to 8% and that for consumers at node B from 33% to 25%. But it increases the cost share for consumers at node C, from 50% to 74%, because they realize the greatest net benefits.

Table 3-4 – Cost Sharing Rules with Efficient Coordination (in $Million)

	Load Sharing	Beneficiary Pay
Consumers at Node A	68	3
Consumers at Node B	133	101
Consumers at Node C	199	296
Total cost	400	400

However, these two cost sharing rules suffer the fundamental pitfalls of all administrative procedures, which include well-documented bureaucratic inefficiencies and vulnerabilities to political capture.

Next, we consider two market-based cost sharing mechanisms, called *constrained efficient* or second-best plans. These approaches are also designed to maximize total surplus, but subject to the constraint that revenues from the project suffice to recover costs. They work by setting energy prices in order to obtain sufficient revenue to cover the investment costs. The first version, called Boiteux-Ramsey I, raises revenue only from congestion charges, whereas the second version, called Boiteux-Ramsey II, assumes that additional revenue can be obtained from an injection charge.

As shown in Table 3-5, under Boiteux-Ramsey I, the difference in energy prices between nodes A and B during the peak period is $17 per MWh and that between nodes B and C is $13. These prices are higher than those with the efficient plan. Moreover, the nodal prices are not uniform during the off-peak period even though there is no congestion. Alternatively, the Boiteux-Ramsey II plan includes an injection fee at each node and has an energy price pattern close to that with the efficient plan. As we will see below, this feature enables the Boiteux-Ramsey II plan to achieve nearly a first-best efficient allocation.

Table 3-5 – Energy Market Prices (in $/MWh)

Period	Node	Efficient Coordination	Boiteux-Ramsey I	Boiteux-Ramsey II	
				Buyer Price	Injection fee
Peak	A	64	61	65	0.66
	B	74	74	75	0.71
	C	79	82	80	0.59
Off Peak	A	27	26	27	0.28
	B	27	27	27	0.27
	C	27	28	27	0.20

In Table 3-6, we show the distribution of consumers and producers surpluses under the four cost sharing rules. Table 3-7 presents essentially the same information in the form of differences relative to Status Quo.

Table 3-6 – Distribution of Consumers and Producers Surpluses

	Node	Efficient Coordination		Boiteux-Ramsey I	Boiteux-Ramsey II
		Load Sharing	Beneficiary Pay		
Consumers Surplus	A	17,183	17,247	17,585	17,199
	B	32,653	32,687	32,919	32,678
	C	47,722	47,625	47,122	47,793
	All	97,559	97,559	97,626	97,670
Producers Surplus	A	4,990	4,990	4,396	4,954
	B	8,924	8,924	8,803	8,888
	C	12,451	12,451	13,081	12,411
	All	26,365	26,365	26,281	26,253
Social Surplus	All	123,923	123,923	123,906	123,923

Table 3-7 – Difference in Consumers and Producers Surpluses Compared to Status Quo

	Node	Efficient Coordination		Boiteux-Ramsey I	Boiteux-Ramsey II
		Load Sharing	Beneficiary Pay		
Consumers Surplus	A	48	113	451	65
	B	3,295	3,328	3,560	3,319
	C	9,922	9,825	9,322	9,993
	All	13,265	13,265	13,332	13,377
Producers Surplus	A	266	266	(329)	229
	B	(3,144)	(3,144)	(3,265)	(3,180)
	C	(8,978)	(8,978)	(8,347)	(9,018)
	All	(11,856)	(11,856)	(11,940)	(11,968)
Social Surplus	All	1,409	1,409	1,392	1,409

From Tables 3-6 and 3-7, we observe that:

- The Boiteux-Ramsey I rule yields the lowest social surplus
- The Boiteux-Ramsey II rule yields a social surplus virtually identical to that with efficient coordination, suggesting that it is nearly as efficient as the first-best efficient plan.
- The welfare impacts of both Boiteux-Ramsey rules are more favorable to consumers and less favorable to generators in comparison with the two administrative rules.
- The Boiteux-Ramsey II rule produces patterns of welfare impacts measured in consumers and producers surpluses similar to those with the efficient plan using the beneficiaries-pay cost sharing rule.

3.3 Responses to Changes in the System

In this subsection we apply the model to studies 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 status quo. 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 the current configuration, the *new* status quo, before the anticipated change is the first-best efficient plan constructed from the previous Status Quo, and the magnitude of the change is assumed to be 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 only the two increments in transmission capacities between A-B and B-C.
- Generation response: optimize only the increments in generation capacities at nodes A, B, and C.
- Coordinated response: optimize both the increments in the three generation capacities and the increments in the two 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.

Tables 8 and 9 show the capacity increments for each of the six scenarios. 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 3-8 – Response to Retirement of Generation at Node B (MW)

	Transmission Response	Generation Response	Coordinated Response
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

Table 3-9 – Response to Demand Increase at Node B (MW)

	Transmission Response	Generation Response	Coordinated Response
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

Tables 10 and 11 display the energy market prices for each of the six scenarios. We find 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 3-10 – Energy Market Prices (in $/MWh) – Generation Retirement at Node B

Period	Node	Transmission Response	Generation Response	Coordinated Response
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

Table 3-11 – Energy Market Prices (in $/MWh) – Demand Increase at Node B

Period	Node	Transmission Response	Generation Response	Coordinated Response
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

Tables 12 and 13 compare the welfare effects on consumers and producers surpluses 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 consumers surplus by $1.5 - $1.9 billion and $1.1 - $1.4 billion, respectively, while increasing the producers surplus by similar amounts. The coordinated response offers the greatest total 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.

Table 3-12 – Consumers and Producers Surpluses – Generation Retirement at Node B

	Node	Transmission Response	Generation Response	Coordinated Response
Consumers Surplus	A	16,680	17,193	17,105
	B	31,672	31,976	32,502
	C	47,437	47,699	47,687
	All	95,789	96,868	97,294
Producers Surplus	A	5,829	4,995	5,120
	B	8,895	8,736	8,239
	C	12,573	12,493	12,462
	All	27,297	26,224	25,821
Social surplus	All	123,086	123,092	123,116

Table 3-13 – Consumers and Producers Surpluses – Demand Increase at Node B

	Node	Transmission Response	Generation Response	Coordinated Response
Consumers Surplus	A	16,571	17,197	17,088
	B	34,605	35,039	35,717
	C	47,380	47,694	47,684
	All	98,555	99,930	100,489
Producers Surplus	A	6,024	4,996	5,154
	B	9,964	9,726	9,084
	C	12,604	12,505	12,467
	All	28,592	27,227	26,704
Social surplus	All	127,147	127,158	127,193

Section 4 – Merchant Transmission Investments

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 and free entry. The rationale for merchant transmission investment has been developed by William Hogan (1992), Paul Joskow and Jean Tirole (2005), and Stephen Littlechild (2011). 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.

4.1 Scenarios of Merchant Investors

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 any two or three among a TransCo, a GenCo, 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 several 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 consider four scenarios of merchant investment in transmission expansion and compare them with efficient coordination.

1. First, we assume that 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. Second, we assume that 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. Third, we assume that 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.
4. Fourth, a more complicated design is a consortium of GenCo A and Utility C, called Merchant TGU-AC, that invest jointly in generation capacity at A and transmission

capacity for lines A-B and B-C, partnering with TransCo to build and maintain the transmission line.

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 total 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. Appendix A includes the mathematical formulation of the efficient coordination model and the four merchant investment models.

4.2 Results and Discussion

Tables 4-1 – 4-3 show the results of the four scenarios of merchant investment in comparison with the efficient plan.

Table 4-1 – Transmission and Generation Capacity Investments

		Efficient Coordination	TransCo	Merchant TG-A	Merchant TU-C	Merchant TGU-AC
Transmission Capacity (MW)	Line A-B	66	31	37	108	142
	Line B-C	53	25	25	76	96
Generation Capacity (MW)	Node A	191	151	154	240	317
	Node B	189	193	190	181	181
	Node C	242	249	241	241	241
Transmission Investment ($Million)		1,324	838	896	1,862	2,306
Generation Investment ($Million)		19,111	19,176	18,880	19,708	21,240
Total Investment ($Million)		21,034	20,014	19,777	21,570	23,546

From Table 4-1, the pattern of investments for merchant alliances TU-C and TGU-AC, which include Utility C as a partner, differ significantly from those for TransCo and TG-A, which do not include Utility C. Compared to the efficient plan, merchants in the former group make greater investments in both transmission ($1.9 - $2.3 billion) and generation ($19.7 – $21.2 billion) capacities, while those in the latter group tend to make smaller transmission investments ($0.8 - $0.9 billion) but mixed generation investments ($18.9 - $19.1 billion). The investment pattern of the former group 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 price levels and nodal price differences.

Table 4-2 shows the effects of the merchant plans on energy market prices, as compared to the efficient plan, at each node. For merchants TransCo and 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 merchants TU-C and TGU-AC, the nodal energy prices are uniform as a consequence of increased transmission investments that eliminate transmission congestion.

Table 4-2 – Energy Market Prices ($/MWh)

Period	Node	Efficient Coordination	TransCo	Merchant TG-A	Merchant TU-C	Merchant TGU-AC
Peak	A	64	60	63	68	59
	B	74	76	74	68	59
	C	79	91	96	68	59
Off Peak	A	27	28	28	25	22
	B	27	28	28	25	22
	C	27	30	32	25	22

Table 4-3 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 4-3 – Distribution of Consumers and Producers Surpluses ($Million)

	Node	Efficient Coordination	TransCo	Merchant TG-A	Merchant TU-C	Merchant TGU-AC
Consumers Surplus	A	17,183	17,553	17,302	17,025	17,478
	B	32,653	32,404	32,668	34,049	34,957
	C	47,722	44,608	43,086	51,074	52,435
	All	97,559	94,564	93,056	102,147	104,870
Producers Surplus	A	4,990	4,531	4,884	5,430	2,711
	B	8,924	9,284	9,034	7,807	6,309
	C	12,451	15,208	16,462	10,103	8,165
	All	26,365	29,023	30,380	23,340	17,185
Congestion revenue		0	79	164	(1,862)	(2,306)
Social surplus	All	123,923	123,665	123,601	123,626	119,749

From the results in Tables 4-1 – 4-3, we observe the following policy implications for merchant investments.

- TransCo could be financially viable, because as shown in Table 4-3, 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 consumers surplus and raises the producers 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 $353 million (from $4,531 million to $4,884 million) and TransCo's profit, the net congestion revenue, by $85 million (from $79 million to $164 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 uncongested 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.
- Among the four merchant scenarios, merchant TGU-AC appears to be both inefficient and unsustainable. It produces the greatest transmission expansion but is least efficient as it reduces the total surplus by $4.2 billion as compared to the efficient plan. Evidently, the investors over-expanded to maximize their own net benefits, without concern for the effects on other market participants. Moreover, this alliance is financially unsustainable because compared to merchant TU-C, it reduces Gen A's profits by $2,719 million and raises TransCo's deficit by $444 million, though this is partially offset by an increase in the consumers surplus at node C of $1,361 million, which is insufficient to support transfer payments to keep both GenCo A and TransCo in the alliance.

Section 5 – Sequential Coordination

In this section, we study the long-term planning strategy of sequential coordination between regulated transmission and merchant generation investments. In sequential coordination, transmission and generation investments are planned sequentially. 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.[12] 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 merchant investments are proposed.[13]

We consider two scenarios:

1) transmission leads generation and
2) transmission follows generation.

In the first scenario, efficient 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. In this scenario, efficient transmission investment is set first according to the efficient plan, and then, optimal generation investment at each node is determined individually on the assumption of Cournot competition among all three generators as though they act simultaneously. In the second scenario, efficient generation capacities are determined first on the assumption that there will be no transmission congestion, and then sufficient transmission capacity is provided to eliminate congestion. This scenario is essentially the same as the uncongested transmission scenario studied in Section 3.

Tables 5-1 – 5-3 summarize the results for these two scenarios and compare them to the efficient plan. As shown in Table 5-1, for the first scenario, where transmission leads generation, the transmission investment is set at the efficient level ($1.3 billion); however, Cournot equilibrium yields lower generation investments ($18.9 billion) than the efficient plan ($19.1 billion). For the second scenario, where transmission follows generation, unfettered competition within an uncongested transmission network results in greater generation investments ($19.7 billion) complementing the increased transmission investments ($1.8 billion) .

[12] This view is encouraged by the longer times for planning and building transmission lines, and their longer useful lives, compared to generation capacity. The present model does not address this aspect.
[13] 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.

Table 5-1 – Transmission and Generation Capacity Investments

		Efficient Coordination	Transmission Leads Generation	Transmission Follows Generation
Transmission Capacity (MW)	Line A-B	66	66	105
	Line B-C	53	53	76
Generation Capacity (MW)	Node A	191	153	237
	Node B	189	193	183
	Node C	242	242	241
Transmission Investment ($Million)		1,324	1,324	1,837
Generation Investment ($Million)		19,111	18,883	19,706
Total Investment ($Million)		20,434	20,206	21,542

Table 5-2 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, respectively $68/MWh and $25/MWh 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.

Table 5-2 – Energy Market Prices ($/MWh)

Period	Node	Efficient Coordination	Transmission Leads Generation	Transmission Follows Generation
Peak	A	64	79	68
	B	74	79	68
	C	79	79	68
Off Peak	A	27	29	25
	B	27	29	25
	C	27	29	25

Table 5-3 shows the effects on producers and consumers surpluses net of costs, as compared to the efficient plan, at each node. In comparison, the second scenario, where transmission-leads-generation, yields a higher social surplus than the first scenario, where transmission-follows-generation. However, the difference is not striking as compared to that with the efficient plan.

A more significant difference lies in the distributional effects. When transmission leads generation, the consumers surplus is lower and the producers surplus is higher, in total, than those resulting from the efficient plan because Cournot equilibrium results in smaller capacities and higher prices. On the other hand, when transmission follows generation, the transmission system is uncongested, and unfettered competition results in greater generation capacities and lower prices.[14] In summary, the coordination strategy of transmission-follows-generation appears to leverage the complementarities between transmission and generation to benefit consumers at large.

Table 5-3 – Distribution of Consumers and Producers Surpluses ($million)

	Node	Efficient Coordination	Transmission Leads Generation	Transmission Follows Generation
Consumers Surplus	A	17,247	16,022	17,046
	B	32,687	31,449	33,590
	C	47,625	46,418	49,745
	All	97,559	93,889	100,381
Producers Surplus	A	4,990	7,088	5,404
	B	8,924	9,932	7,803
	C	12,451	12,692	10,079
	All	26,365	29,712	23,286
Social surplus	All	123,923	123,601	123,667

[14] This observation resembles the result obtained by David Kreps and Jose Scheinkman (1983), that two-stage competition in which initial capacity commitments are followed by price competition for sales in the energy market (assuming rationing there is efficient) yields the same outcome as one-stage Cournot competition.

Section 6 – Concluding Remarks

There are two parts of the work reported here. One part proposes an economic framework for developing plans that promote 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 report 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. 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 problem of optimization 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.

In the version described in this paper, the model is simplified 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 other situations it may be necessary to work with an expanded model allowing more general specifications, or to work directly with market and engineering data – but this requires more powerful computational programs than the Excel spreadsheet used for the illustrations reported here.

We also see the economic framework and the analytical model as useful in studies of basic conceptual issues. Two such issues illustrated in this report 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. More generally, the model can be used as an exploratory tool for analyzing complex scenarios and deriving the magnitudes of effects on prices and welfare.

Appendix A - Mathematical Formulation of the Basic Model

In this appendix, we describe a two-stage stochastic decision model for transmission and generation capacity planning in the environment of competitive wholesale electricity markets. We assume that decisions about new investments in transmission and generation capacities are made before the uncertainties are resolved, and electricity demands, supplies and prices as well as power flows on the electric network are determined through competitive market trading.

The planner's objective is to maximize the total surplus, which is the sum of consumers' surplus and producers' surplus, adopting the standard social welfare measure from the basic economic principle of public policy. The model informs the planner about the merits of alternative approaches in a manner that reflects the welfare impacts on diverse stakeholders under uncertain market and physical conditions. In the following, we describe the basic model under two assumptions about the structure of the electric network: a generic network with AC power flows and a simplified version that has a tree structure with no loop-flows.

Listed below are the symbols used in the basic model, with boldface letters denoting vectors, matrices or random variables.

Notation

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

$N_i \subset N$: the set of nodes linked to node i in the electric network.

$t \in T \equiv \{1, 2, \ldots, T\}$: time periods in the second stage

$I(K_{ij})$: The transmission investment cost for capacity of link (i, j), K_{ij}.

$k_n Y_n$: The cost of generation investment for capacity Y_n.

$\mathbf{q}_n = (\mathbf{q}_{n1}, \ldots, \mathbf{q}_{nT})$: The vector of energy consumption levels at node n in period t.

$\mathbf{x}_n = (\mathbf{x}_{n1}, \ldots, \mathbf{x}_{nT})$: The vector of energy production levels at node n in period t.

$\mathbf{p}_n = (\mathbf{p}_{n1}, \ldots, \mathbf{p}_{nT})$: The vector of energy prices at node n in period t.

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

$\mathbf{D}_{nt}(\mathbf{p})$: The energy demand function at node n in period t.

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

$\mathbf{C}_{nt}(\mathbf{x}, Y)$: The total cost of energy generation $\mathbf{x}$ at node n in period t.

$\mathbf{c}_{nt}(\mathbf{x}, Y) \equiv \dfrac{\partial \mathbf{C}_{nt}(\mathbf{x}, Y)}{\partial x}$: The marginal cost of energy at node n in period t.

$\mathbf{S}_{nt}(\mathbf{p}, Y) = \mathbf{c}_{nt}^{-1}(\mathbf{p}, Y)$: The energy supply function at node n in period t.

$\boldsymbol{\theta}_{nt}$: the voltage angle at node n in period t.

$\boldsymbol{\Phi}_{ij}(\boldsymbol{\theta}_i - \boldsymbol{\theta}_j)$: power flow from node i to node j according to the Kirchhoff's laws.

$\boldsymbol{\Lambda}(\boldsymbol{\theta}) \equiv \sum_{i,j \in N} \boldsymbol{\Phi}_{ij}(\boldsymbol{\theta}_i - \boldsymbol{\theta}_j)$: The total transmission loss function

The Basic Model

The objective in the basic model is set to maximize the social welfare, which is the sum of consumers and producers surplus minus net transmission costs, subject to the energy balance and power flow constraints. The model is summarized in (1) – (5) as follows,

$$\underset{(K_{ij}, Y_n, \mathbf{p}_n, \boldsymbol{\theta}_n)}{Max} \; E\left\{ \sum_{n \in N} \sum_{t \in T} \mathbf{U}_{nt}\left(\mathbf{D}_{nt}(\mathbf{p}_{nt})\right) - \mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n), Y_n\right) \right\} - \sum_{n \in N} k_n Y_n - \sum_{i,j \in N} I(K_{ij}) \tag{1}$$

subject to

$$\sum_{n \in N} \left[\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n) - \mathbf{D}_{nt}(\mathbf{p}_{nt}) \right] = \boldsymbol{\Lambda}(\boldsymbol{\theta}), \text{ for } t \in T. \tag{2}$$

$$\mathbf{S}_{it}(\mathbf{p}_{it}, Y_i) - \mathbf{D}_{it}(\mathbf{p}_{it}) = \sum_{j \in N_i} \boldsymbol{\Phi}_{ij}(\boldsymbol{\theta}_i - \boldsymbol{\theta}_j), \text{ for } i \in N \text{ and } t \in T. \tag{3}$$

$$\mathbf{D}_{it}(\mathbf{p}_{it}) - \mathbf{S}_{it}(\mathbf{p}_{it}, Y_i) = \sum_{j \in N_i} \boldsymbol{\Phi}_{ji}(\boldsymbol{\theta}_j - \boldsymbol{\theta}_i), \text{ for } i \in N \text{ and } t \in T. \tag{4}$$

$$\boldsymbol{\Phi}_{ij}(\boldsymbol{\theta}_i - \boldsymbol{\theta}_j) \le K_{ij} \qquad \text{for } i, j \in N \text{ and } t \in T. \tag{5}$$

Conditions (2) – (5) represent the system balancing and power flow constraints. Equation (2) states that the net energy supply on the system equals to the total transmission losses. Equation (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. Similarly, Equation (4) states that the net demand at each node equals the sum of power flows into this node from all of its adjacent nodes. Condition (5) states that for each link, the power flow cannot exceed the thermal capacity of the link.

Analytically, the basic model is a two-stage stochastic program. The transmission and generation capacity decisions are determined in the first stage independent of the random outcomes in individual time periods. Then, in the second stage, competitive energy prices are determined in each period after the resolution of the random variables. Note that the two-stage stochastic program is feasible only if the constraints (2) – (5) can be met for every random outcome in each period. In other words, the system is robust and secure against all possible contingencies. This is plausible if the energy demand functions are elastic in responding to high prices or sufficient transmission and generation capacities can be built in time to provide adequate reserves to insure against the extreme conditions. However, in practice, rigidities in system response may create situations that require additional constraints, such as imposing a maximum loss of load probability, may be justified. The basic model can be extended in a straightforward manner to incorporate such constraints as needed.

The Basic Model - A Simplified Version

For our purposes, it is sufficient to consider a simplified version of the basic model for a three-node network with a tree structure, A-B-C ($N = \{A, B, C\}$ and $G = \{(A,B),(B,C)\}$), 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 about the complexities associated with the physical laws and loop-flows in an AC power network. (Chao and Peck, 1996) Therefore, Expressions (1) – (5) in the basic model can be restated as follows,

$$\underset{(K_{ij}, Y_n, \mathbf{p}_n)}{Max} \; E\left\{\sum_{n \in N}\sum_{t \in T} \mathbf{B}_{nt}\left(\mathbf{D}_{nt}(\mathbf{p}_{nt})\right) - \mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n), Y_n\right)\right\} - \sum_{n \in N} k_n Y_n - \sum_{(i,j) \in G} I(K_{ij}) \tag{6}$$

subject to

$$\sum_{n \in N}\left[\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n) - \mathbf{D}_{nt}(\mathbf{p}_{nt})\right] = 0, \text{ for } t \in T. \tag{7}$$

$$\left|\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n) - \mathbf{D}_{nt}(\mathbf{p}_{nt})\right| \le K_{nB}, \text{ for } n \ne B,\; n \in N,\; t \in T. \tag{8}$$

Under the assumption that the gross consumer benefit functions are concave and the generation cost functions are convex, the basic 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. To address this issue, we consider two variants of the basic model: 1) the second-best cost allocation mechanism and 2) merchant transmission investments.

The Second-Best Cost Allocation Mechanism

We consider two second-best cost allocation mechanisms called Ramsey-Boiteux pricing because they derive from proposals by Marcel Boiteux (1956) and Frank Ramsey (1927). The two second-best plans also maximize the total surplus, but subject to the constraint that transmission costs are fully recovered from transmission revenues. In one version (Boiteux-Ramsey Plan I) the transmission revenue consists only of congestion charges, and in the other (Boiteux-Ramsey Plan II) additional revenue is obtained from injection charges.

Ramsey-Boiteux Plan I

$$\underset{(K_{ij}, Y_n, \mathbf{p}_n)}{Max}\ E\left\{\sum_{n\in N}\sum_{t\in T}\mathbf{B}_{nt}\left(\mathbf{D}_{nt}(\mathbf{p}_{nt})\right)-\mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n), Y_n\right)\right\}-\sum_{n\in N}k_n Y_n-\sum_{(i,j)\in G}I(K_{ij}) \tag{6}$$

subject to

$$\sum_{n\in N}\left[\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right]=0\text{, for } t\in T. \tag{7}$$

$$\left|\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\le K_{nB}\text{, for } n\ne B,\ n\in N,\ \ t\in T. \tag{8}$$

$$\sum_{n\in N}\sum_{t\in T}\left[\mathbf{p}_{nt}\mathbf{D}_{nt}(\mathbf{p}_{nt})-\mathbf{p}_{nt}\mathbf{S}_{nt}(\mathbf{p}_{nt}, Y_n)\right]\ge I_{AB}(K_{AB})+I_{BC}(K_{BC}). \tag{9}$$

Equations (6) – (8), which are identical to those in the basic model, are included for completeness. Equation (9) requires that transmission congestion revenues are sufficient to cover the transmission investment costs.

Ramsey-Boiteux Plan II

$$\underset{(K_{ij}, Y_n, \mathbf{p}_n^d, \mathbf{p}_n^s)}{Max}\ E\left\{\sum_{n\in N}\sum_{t\in T}\mathbf{B}_{nt}\left(\mathbf{D}_{nt}(\mathbf{p}_{nt}^d)\right)-\mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt}^s, Y_n), Y_n\right)\right\}-\sum_{n\in N}k_n Y_n-\sum_{(i,j)\in G}I(K_{ij}) \tag{10}$$

subject to

$$\sum_{n\in N}\left[\mathbf{S}_{nt}(\mathbf{p}_{nt}^s, Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt}^d)\right]=0\text{, for } t\in T. \tag{11}$$

$$\left|\mathbf{S}_{nt}(\mathbf{p}_{nt}^{s},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt}^{d})\right|\le K_{nB}\text{, for } n\neq B,\ n\in N,\ \ t\in T. \tag{12}$$

$$\sum_{n\in N}\sum_{t\in T}\left[\mathbf{p}_{nt}^{d}\mathbf{D}_{nt}(\mathbf{p}_{nt}^{d})-\mathbf{p}_{nt}^{s}\mathbf{S}_{nt}(\mathbf{p}_{nt}^{s},Y_n)\right]\ge I_{AB}(K_{AB})+I_{BC}(K_{BC}). \tag{13}$$

Conditions (10) – (13) are similar to those in (6) – (9), but differ in one important aspect: the Ramsey-Boiteux Plan II 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.

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 four possible types of merchants: 1) a pure transmission merchant, TransCo, 2) a generation and transmission merchant, GenCo A and TransCo, 3) a utility and transmission merchant, Utility C and TransCo, and 4) a merchant consortium of generation, utility and transmission, GenCo A & Utility C & 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 (7) and (8) remain applicable.

TransCo

$$\underset{(K_{ij},Y_n,\mathbf{p}_n)}{Max}\ E\left\{\sum_{n\in N}\sum_{t\in T}\left[\mathbf{p}_{nt}\mathbf{D}_{nt}(\mathbf{p}_{nt})-\mathbf{p}_{nt}\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)\right]\right\}-\sum_{(i,j)\in G}I(K_{ij}) \tag{14}$$

subject to

$$\sum_{n\in N}\left[\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right]=0\text{, for } t\in T. \tag{7}$$

$$\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\le K_{nB}\text{, for } n\neq B,\ n\in N,\ \ t\in T. \tag{8}$$

$$\left(p_{nt}-p_{Bt}\right)\left[K_{nB}-\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\right]=0\quad\text{for } n\neq B,\ n\in N,\ \ t\in T. \tag{15}$$

$$E\left\{\sum_{t\in T}\frac{\partial \mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n),Y_n\right)}{\partial Y_n}\right\}+k_n=0\text{, for } n\in N. \tag{16}$$

Expression (14) is the profit for a pure merchant transmission company. Condition (15) requires that nodal prices between two nodes across an uncongested transmission link must be zero. Equation (16) represents the efficient investment conditions for merchant generators in a competitive equilibrium.

GenCo A & TransCo

$$\underset{(K_{ij},Y_n,\mathbf{p}_n)}{Max}\ E\left\{\sum_{t\in T}\left[\mathbf{p}_{At}\mathbf{S}_{At}(\mathbf{p}_{At},Y_A)-\mathbf{C}_{At}\left(\mathbf{S}_{At}(\mathbf{p}_{At},Y_A),Y_A\right)\right]-k_AY_A\right\}$$

$$+E\left\{\sum_{n\in N}\sum_{t\in T}\left[\mathbf{p}_{nt}\mathbf{D}_{nt}(\mathbf{p}_{nt})-\mathbf{p}_{nt}\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)\right]\right\}-\sum_{(i,j)\in G}I(K_{ij}) \tag{17}$$

subject to

$$\sum_{n\in N}\left[\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right]=0,\ \text{for } t\in T. \tag{7}$$

$$\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\le K_{nB},\ \text{for } n\ne B,\ n\in N,\ \ t\in T. \tag{8}$$

$$\left(p_{nt}-p_{Bt}\right)\left[K_{nB}-\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\right]=0\quad \text{for } n\ne B,\ n\in N,\ \ t\in T. \tag{15}$$

$$E\left\{\sum_{t\in T}\frac{\partial\mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n),Y_n\right)}{\partial Y_n}\right\}+k_n=0,\ \text{for } n\ne A,\ n\in N. \tag{18}$$

In comparison with the case with a pure transmission merchant, GenCo A's profit is added to the objective function (17) while the competitive investment condition for the generator is excluded from (18).

Utility C and TransCo

$$\underset{(K_{ij},Y_n,\mathbf{p}_n)}{Max}\ E\left\{\sum_{t\in T}\left[\mathbf{B}_{Ct}\left(\mathbf{D}_{Ct}(\mathbf{p}_{Ct})\right)-\mathbf{p}_{Ct}\mathbf{S}_{Ct}(\mathbf{p}_{Ct},Y_C)\right]\right\}$$

$$+E\left\{\sum_{n\in N}\sum_{t\in T}\left[\mathbf{p}_{nt}\mathbf{D}_{nt}(\mathbf{p}_{nt})-\mathbf{p}_{nt}\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)\right]\right\}-\sum_{(i,j)\in G}I(K_{ij}) \tag{19}$$

subject to

$$\sum_{n\in N}\left[\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right]=0,\ \text{for } t\in T. \tag{7}$$

$$\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\leq K_{nB}\text{, for } n\neq B,\ n\in N,\ \ t\in T. \tag{8}$$

$$\left(p_{nt}-p_{Bt}\right)\left[K_{nB}-\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\right]=0 \quad \text{for } n\neq B,\ n\in N,\ \ t\in T. \tag{15}$$

$$E\left\{\sum_{t\in T}\frac{\partial\mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n),Y_n\right)}{\partial Y_n}\right\}+k_n=0\text{, for } n\in N. \tag{16}$$

In comparison with the case of TransCo, the only difference lies in the objective function (19).

GenCo A & Utility C & TransCo

$$\underset{(K_{ij},Y_n,\mathbf{p}_n)}{Max}\ E\left\{\sum_{t\in T}\left[\mathbf{B}_{Ct}\left(\mathbf{D}_{Ct}(\mathbf{p}_{Ct})\right)-\mathbf{p}_{Ct}\mathbf{S}_{Ct}(\mathbf{p}_{Ct},Y_C)\right]\right\}$$

$$+E\left\{\sum_{t\in T}\left[\mathbf{p}_{At}\mathbf{S}_{At}(\mathbf{p}_{At},Y_A)-\mathbf{C}_{At}\left(\mathbf{S}_{At}(\mathbf{p}_{At},Y_A),Y_A\right)\right]-k_AY_A\right\}$$

$$+E\left\{\sum_{n\in N}\sum_{t\in T}\left[\mathbf{p}_{nt}\mathbf{D}_{nt}(\mathbf{p}_{nt})-\mathbf{p}_{nt}\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)\right]\right\}-\sum_{(i,j)\in G}I(K_{ij}) \tag{20}$$

subject to

$$\sum_{n\in N}\left[\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right]=0\text{, for } t\in T. \tag{7}$$

$$\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\leq K_{nB}\text{, for } n\neq B,\ n\in N,\ \ t\in T. \tag{8}$$

$$\left(p_{nt}-p_{Bt}\right)\left[K_{nB}-\left|\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n)-\mathbf{D}_{nt}(\mathbf{p}_{nt})\right|\right]=0 \quad \text{for } n\neq B,\ n\in N,\ \ t\in T. \tag{15}$$

$$E\left\{\sum_{t\in T}\frac{\partial\mathbf{C}_{nt}\left(\mathbf{S}_{nt}(\mathbf{p}_{nt},Y_n),Y_n\right)}{\partial Y_n}\right\}+k_n=0\text{, for } n\neq A,\ n\in N. \tag{18}$$

This case is similar to GenCo A & TransCo, and the only difference lies in the objective function (20).

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