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Two-Settlement Systems for Electricity Markets: Zonal Aggregation Under Network Uncertainty and Market Power

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TWO-SETTLEMENT SYSTEMS FOR ELECTRICITY MARKETS: ZONAL AGGREGATION UNDER NETWORK UNCERTAINTY AND MARKET POWER

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Abstract

We analyze welfare properties of two-settlement systems for electricity in the presence of network uncertainty and market power. We formulate and analyze several models which simulate the different market designs adopted or proposed for many electricity markets around the world. In particular, we examine the extent to which a two-settlement system with zonal aggregation in the forward market facilitates forward trading, as well as the welfare and distributional implications of having such zonal aggregation in the presence of network uncertainty. Using a duopoly model over simple two- and three-node networks, we show that for even small probabilities of congestion, forward trading may be substantially reduced, and the market power mitigating effect of forward markets (as shown in Allaz and Vila, 1993) may be nullified to a great extent. We find that the imposition of a delivery requirement on the forward contract in the form of a spot transmission charge alleviates some of the incentive problems associated with zonal aggregation. Even with the imposition of the spot transmission charge, we find that some reduction in forward trading persists due to the segregation of the markets in the constrained state, and the absence of natural incentives for generators to commit to more aggressive behavior in the spot market. In our analysis, we find that the standard assumption of 'no-arbitrage' across forward and spot markets leads to very little contract coverage even in the no congestion case. We provide an alternative view of the market where we assume that all of the demand shows up in the forward market, and is aggregated to determine the forward price using a 'market clearing' condition.

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1. Introduction

In the past few years, wholesale electricity markets have gone through fundamental changes in the U.S. and around the world.[1] Electricity industry restructuring began in Latin American countries in the early 1980s, and more famously, in the United Kingdom in 1990. In the late 1990s, several U.S. states or control areas such as California, Pennsylvania-New Jersey-Maryland (PJM) Interchange, New York, and New England established markets for electricity; and more recently, FERC Order has prompted several proposals for the establishment of Regional Transmission Organizations (RTOs). Two key common aspects of the transition toward competitive electricity markets in the U.S. and around the world, are a competitive generation sector and open access to the transmission system. However, there is considerable diversity among the implementation paths chosen by different states and countries. The differences are reflected in various aspects of market design and organization, such as groupings of functions, ownership structure, and the degree of decentralization in markets. The experience gained from the first wave of restructuring in places such as the United Kingdom, Scandinavia, California, and PJM, have led to several reassessment and revision proposals of various market design aspects in these jurisdictions.

Two major themes in market design have emerged in the restructuring process, and have been implemented or currently proposed for the various markets in the U.S. The first one, relies on centralized dispatch of all resources in the market, variations of which are implemented in the PJM Interchange, New

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[1] See Einhorn (1994), Gilbert and Kahn (1996), and Chao and Huntington (1998) for surveys on the subject.

York, and New England (see Garber, Hogan and Ruff, 1994; Budhraja and Woolf, 1994). In this design, an independent system operator runs a real-time market with centralized dispatch. Bilateral trades are allowed in this system though they are purely financial in nature and do not get scheduling priority. Bilateral trades are charged locational price differences in the real-time market, and these can be hedged by some type of transmission congestion contracts, which are again financial instruments that guarantee the holder the price differential between locations specified in the contract (see Hogan, 1992 and Harvey, Hogan and Pope, 1997).[2]

The second design relies on a more decentralized approach, at least in the day-ahead energy market. The version that was originally implemented in California had two separate entities, a Power Exchange (PX), which was one of many short-term forward markets, and an independent system operator (ISO), which managed real-time operations (see Blumstein and Bushnell, 1994; Wilson, 1997).[3] The version implemented in Texas relies on bilateral trading and private exchanges for day-ahead energy trading, and some of the emerging RTOs also rely on various forms of decentralized day-ahead markets. The key feature of this scheme is that day-ahead energy trading and settlements are based on a simplified 'commercial model' of the transmission network where nodes are grouped into few zones, and only few interzonal transmission constraints (deemed commercially significant - CSC) are enforced (i.e., priced) on day-ahead schedules submitted to the system operator. Congestion on CSCs can be hedged through financial or physical rights on these constrained interfaces. Such zonal aggregation facilitates liquidity of the day-ahead market but it allows scheduling of transactions that are physically impossible to implement due to reliability constraints. A centrally coordinated real-time physical market in which operational decisions are based on an accurate "operational model" of the transmission grid corrects these infeasibilities. The extent to which financial settlements in the real-time market reflect operational realities is a highly debated issue that is not yet resolved in many of the emerging RTOs. The debate

[2] Current implementations at PJM, New York and New England allow physical bilateral contracts, which are interpreted as zero offers on the injection side and infinite bids on the load side.

[3] The PX was dissolved in January, 2001.

concerns the extent to which the costs of correcting infeasible schedules should be directly assigned to those that cause such infeasibilities, as opposed to socializing these costs through uniform or load-share based uplift charges.

The main goal of this paper is to examine the extent to which a two-settlement system with zonal aggregation in the forward market facilitates forward trading, as well as the welfare and distributional implications of having such zonal aggregation in the presence of network uncertainty and generator market power. As a benchmark for comparison we use a single-settlement nodal model.[4] The remainder of the paper is as follows. The next section provides a review of the relevant literature on spot market modeling, modeling interactions between spot and contract markets, and approaches to transmission pricing. Section 3 presents formulations of the various market designs analyzed in this study. In Section 4, we analyze the impact of network uncertainty in a simple two-node example. In Section 5, we extend our analysis to a three-node example with loop-flow. Section 6 provides some concluding remarks and addresses future work.

2. Literature Review

We review literature on electricity market modeling, both with and without transmission constraints, and models with contracts. While some electricity market models have attempted to include transmission constraints, models with two-settlement systems (or forward energy contracts) usually treat the electricity market as if it is deliverable at a single location. We also review the market designs in greater detail specifically with respect to transmission pricing.

2.1. Electricity Market Models

Schweppe et al. (1988) originated the theory of competitive electricity locational spot prices. Given costs of all generators on the network, demand, and network topology, locational prices can be calculated using

[4] We ignore transmission contracts in this study, and focus on a market with a single zone.

an optimal power flow model, which seeks to minimize the total cost of generation. In a decentralized environment, these prices can elicit the optimal quantities from competitive agents. Differences in locational prices reflect differences in equilibrium marginal costs at various locations, and can be used to set transmission charges for bilateral contracts (Schweppe et al., 1986; Hogan, 1992). Later studies, however, have considered the effect of generator market power in electricity markets. Equilibria with two conjectural variations, supply function equilibria (see Klemperer and Meyer, 1989), and Cournot-Nash equilibria have been examined.

2.1.1. Models without Transmission Constraints

Green and Newbery (1992), use supply function equilibria to describe the electricity spot market in England and Wales soon after deregulation in 1990.[5] In a supply function equilibrium (SFE), each firm submits a non-decreasing supply function specifying the quantity it is willing to provide at a given price. These functions can be derived as solutions to a set of coupled differential equations. Green and Newbery find that in the short-term (until new entry that was proposed was set up), the incumbents had significant market power, and large deadweight losses could result if they compete in a SFE. They also argue that the amount of planned entry is more than is socially desirable, and could cause substantial deadweight losses in the future due to the unnecessary expense in investment. Bolle (1992) also considers several models of SFE in which consumers react to a fixed price, to average spot prices, and directly to spot prices. He allows for backward bending supply functions, and finds a continuum of equilibria in all cases. He recommends that consumers be directly exposed to spot prices as this is the only model in which increasing the number of firms results in more competitive behavior. Bolle (2001) extends the earlier

[5] One of the arguments in favor of deregulation of the generation sector was that generators would compete as Bertrand oligopolists and this would result in competitive prices. Also, it was argued that the threat of entry by small and efficient combined cycle gas powered capacity would bring the necessary discipline to the market. In the immediate years after deregulation, however, a duopoly existed, with two firms -- National Power and Powergen -- controlling 80 percent of the generation capacity and with substantial price setting power. In the daily market run by the grid operator, National Grid Company, these firms submitted a supply schedule for each generator under their

analysis to include demand side bidding. In a detailed analysis, he derives power series solutions for supply function equilibria in supply and demand functions, and analyzes restrictions on free parameters of the solution in order to get meaningful solutions with positive prices and quantities, upward sloping supply functions and downward sloping demand functions, and positive excess supply to meet autonomous demand. Bolle finds that these restrictions may imply that prices may in general be bounded away from marginal cost and computes lower bounds for some cases. Another interesting result is that prices resulting from pure strategy equilibria may be bounded away from marginal cost even for an infinite support of autonomous demand, a result that is in contrast to Klemperer and Meyer's (1989) result.

Andersson and Bergman (1995) calculate Bertrand and Cournot-Nash equilibria under various assumptions in an ex-ante analysis of the Swedish electricity market. They find that deregulation is not a sufficient condition for lower equilibrium prices given the structure of the market at that time (two firms controlled seventy-five percent of the market). They find that increasing the number of firms in the market to about five equal size firms would bring discipline to prices, as would higher demand elasticity and monopsony power.

Newbery (1995) examines equilibria with capacity constraints, and again considers issues of entry into the England and Wales market, while Green (1996) examines how many firms would be required for a more competitive market. Rudkevich, Duckworth and Rosen (1998) and Bohn, Klevorick and Stalon (1999) apply these techniques to U.S. markets. Rudkevich et al. propose an iterative scheme for linear marginal costs, which converges to the unique linear SFE for this case. Baldick, Grant and Kahn (2000) generalize this to the case of asymmetric plants with affine marginal costs, where supply functions can be linear or piecewise linear. They also propose an ad-hoc approach to deal with capacity constraints in this case.

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control. The grid operator aggregated these schedules, and using optimization software calculated a system marginal price, which was paid to all generators. Other payments for start-up costs and capacity availability were also made.

von der Fehr and Harbord (1993) consider the electricity market in England and Wales as a multiunit auction and examine equilibria under capacity constraints. They find that when firms have to bid discontinuous step functions instead of continuous supply functions there are no pure strategy equilibria comparable to SFE equilibria. They find mixed strategy equilibria instead; though pricing above marginal costs is seen in many equilibria they derive. Marín Uribe and Garcia-Diaz (2000) extend von der Fehr and Harbord's model to allow for any technology mix and elastic demand in an application to the Spanish market.

In another application to the Spanish electricity market, Ramos, Ventosa and Rivier (1998) combine a traditional production cost model with equilibrium constraints for modeling profit maximizing by individual firms, and approximate a decentralized equilibrium in an 'optimization with equilibrium constraints' framework. They maintain a detailed representation of the electric system operation by considering ramp-rates, minimum up and down times, and operational features of hydro plants. However, they compute linear prices, i.e. there is a uniform price paid to all generation in a period, and so, total amount paid to generation across periods is linear in price for any period. It is not clear whether in a decentralized situation such linear equilibria exist due to the non-convexities in the cost-structure.[6]

2.1.2. Models with Transmission Constraints

Most of the models with transmission constraints assume the Cournot conjectural variation.[7] An important modeling choice in these models is the assumption on whether agents will game transmission markets. This may have an impact on the amount of congestion rent paid to transmission rights holders. Assuming that agents will game the market, however, leads to non-convex problems with possibly multiple equilibria (see Oren, 1997a; Cardell, Hitt and Hogan, 1997 among others).[8] On the other hand, if the main

[6] See Johnson, Oren and Svoboda (1997).

[7] See Smeers (1997) for a discussion on computable equilibrium models of restructured electricity markets. A variation on the Cournot assumptions is to model supply function equilibria using a scalar or two-parameter strategy vector (see Berry et al., 1999; Hobbs, Metzler and Pang, 2000; Day, Hobbs and Pang, 2001).

[8] See Luo, Pang and Ralph (1996) for a comprehensive analysis of such problems.

purpose of the model is to model generator behavior in the energy market, assuming that agents act as price takers in the transmission market allows the models to be solved as complementarity problems or variational inequalities (see Hobbs, 2001; Smeers and Wei, 1997b).

Cardell, Hitt and Hogan (1997) consider a model with Cournot generators who may own plants at multiple locations on a network, and a competitive fringe that takes the strategic generators' quantities as given, and act as price takers in the spot market. A complicating feature of this model is that with the introduction of a competitive fringe, a given strategy profile of the generators may not lead to a unique outcome in the spot market. Another feature is that the strategy sets, and not just the objective function values, of the generators depend on the actions chosen by other generators. This type of game is called a "generalized Nash game" (see Harker, 1991) and can have multiple equilibria. Cardell et al. use an iterative procedure, solving a relaxed form of each Cournot generator's non-convex optimization problem in sequence, and report that a nonlinear solver always found solutions that satisfied a Cournot equilibrium test. A significant result coming out of their work is that generators owning multiple units on a network may not necessarily reduce output in all of them. In fact, increasing output on some generators may give it a strategic advantage by forcing out some competition on another part of the network, and due to transmission constraints, allow it to earn more profits on its remaining capacity (also see Hogan, 1997). Hobbs, Metzler and Pang (2000) solve a similar problem, where generators have a scalar intercept mark-up strategy, using an interior point algorithm. Their model does not consider a competitive fringe.[9] Berry et al. (1999) consider the effect of network structure and capacity limits on competitive behavior in linear supply functions. They retain the assumption that generators game the transmission network. Using two and four node network examples, they show that effective transmission congestion rent can be reduced through strategic bidding in supply functions. Other effects such as decreased efficiency from decreasing concentration are also observed in a four node network.

[9] Having a competitive fringe would imply that transmission prices reflect the opportunity cost of marginal energy trades. Cournot generators would therefore have less control over transmission revenues that the system operator

Borenstein, Bushnell and Stoft (1999) show that interactions among Cournot generators in the presence of a transmission constraint can be quite complex. They show that in a spatially separated market with a symmetric duopoly, and with a small enough transmission line, no pure strategy Cournot equilibria exists. This is due to the fact that there are discontinuities in the response functions of the generators. Along the response function, one generator produces a constant amount, congesting the transmission line in the direction of the other market until the other generator's production reaches a threshold level, at which point it increases its output proportionally. At another threshold level, the first generator abandons this strategy and reverts to a defensive strategy with smaller production than in the first case mentioned above. The authors also analyze cases where passive-aggressive or multiple equilibria can exist.

The above approach of solving generators' optimization problem sequentially implies that generators will take into account how their actions affect transmission prices. Some other models do away with this complication by assuming that generators do not game the transmission system. This removes the non-convexity from each generator's optimization problem. First order conditions for all the generators can now be aggregated along with those of transmission owners, and the equilibrium can be solved as a complementarity problem. Wei and Smeers (1997) consider a Cournot model with regulated transmission prices (Smeers and Wei, 1997b consider a model with a transmission market). They solve variational inequalities to determine unique long-run equilibria in their models. Smeers and Wei (1997a) consider a separated energy and transmission market, where the system operator conducts a transmission capacity auction, and power marketers purchase transmission contracts to support bilateral transactions. They find that such a market converges to the optimal dispatch for a large number of marketers. Borenstein and Bushnell (1999) use a grid search algorithm to iteratively converge to a Cournot model with data on the California market. Hobbs (2001) uses linearly decreasing demand and constant marginal cost functions, which result in linear mixed complementarity problems, to solve for such Cournot

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collects. Assuming an intercept mark-up strategy gives supplier in this paper an additional degree of freedom to equilibria. In a bilateral market, Hobbs analyzes two types of markets, with and without arbitrageurs. In the market without arbitrageurs, non-cost based differences can arise because the bilateral nature of the transactions gives generators more degrees of freedom to discriminate between electricity demand at various nodes. This is equivalent to a separated market as in Smeers and Wei (1997a). In the market with arbitrageurs any non-cost differences is subject to arbitrage by traders who buy and sell electricity at nodal prices. This equilibrium is shown to be equivalent to a Cournot-Nash equilibrium in a POOLCO-type market.

2.1.3. Empirical Work on Market Power

Empirical evidence to support the hypothesis that electricity markets are susceptible to market power can be found in Wolak and Patrick (1997), Borenstein, Bushnell and Wolak (1999), Wolfram (1998 and 1999), Mansur (2001), and Puller (2001). These studies focus on the U.K., California and PJM markets. Borenstein, Bushnell and Stoft (1999) calculate price cost margins in California by estimating expected aggregate marginal cost curves for thermal generation. They use system-wide demand as the market clearing quantity, and the unconstrained PX price as the market-clearing price. In calculating the marginal cost curve they account for must-take generation, hydroelectric load, imports etc., and for thermal capacity, they perform Monte Carlo simulation to calculate expected marginal cost at the net market clearing quantity for thermal capacity.[10] They find that overall prices averaged about 15% above the competitive level for the summer of 1998. Wolfram (1999) and Mansur (2001) use similar methodology for the U.K. and PJM markets, respectively. Puller (2001) uses firm-level data to analyze pricing behavior in the first two years of the California market. Puller tests both static and dynamics models of oligopoly, and finds evidence that generating firms used static market power in this period.

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manipulate congestion revenues.

[10] However, they do not include inter-temporal costs arising from unit-commitment constraints.

2.2. Electricity Market Models with Spot and Contract Markets

Work in this area has focused on the welfare enhancing properties of forward markets and the commitment value of forward contracts. Theoretical studies have shown that for certain conjectural variations, forward markets increase economic efficiency through a prisoners' dilemma type of effect (see Allaz, 1992, and Allaz and Vila, 1993).[11] Other theoretical literature has analyzed the commitment value of contracts as barriers to entry (see Aghion and Bolton, 1987). Applications to electricity markets seem to focus mainly on these two issues.

2.2.1. Theory

The basic model in Allaz (1992) is that producers meet in a two period market where there is some uncertainty in demand in the second period. In the first period, producers buy or sell contracts and a group of speculators take opposite positions. In the second period, a non-competitive market with Cournot conjectures is modeled. A no-arbitrage relation between forward and expected spot prices decides the forward price. If all speculators are risk averse, the forward price contains a risk premium, otherwise if one or more risk neutral speculators are present, the forward price is an unbiased estimator of the spot price. Allaz shows that generators have a strategic incentive to contract forward if other producers do not. This result can be understood using the strategic substitutes and complements terminology of Bulow, Geneakoplos and Klemperer (1985). Essentially, the Cournot conjectural variation implies that production quantities are strategic substitutes. This is because an increase in one producer's quantity has a negative effect on the other's marginal profitability, and thus its best response is lower than was previously optimal. The availability of the forward market makes a particular producer more aggressive in the spot market. Due to the strategic substitutes effect, this produces a negative effect on its competitor's production, and the resulting price decrease is not as severe as it would have been if its competitor had not reacted. The producer with access to the forward market can therefore use its forward commitment to

[11] This effect is not seen, for example, with the Bertrand conjectural variation.

improve its profitability to the detriment of its competitor.[12] Allaz shows, however, that if all producers have access to the forward market, it leads to a prisoners' dilemma type of effect, reducing profits of all producers. Social welfare measured as the sum of consumer and producer surpluses is higher than in a single-settlement case with producers behaving à la Cournot. Allaz points out that the results are very sensitive to the kind of conjectural variation assumed, and shows that Cournot and market-sharing conjectural variations in the forward market lead to very different results. Allaz and Vila (1993) extend this result to the case where there is more than one time period where forward trading takes place. For a case with no uncertainty, they establish that as the number of periods when forward trading takes place tends to infinity, producers lose their ability to raise market prices above marginal cost and the outcome tends to the competitive solution. Haskel and Powell (1994) extend these results to general conjectural variations in the spot market.

An important consideration in electricity markets is that generators meet in these markets almost on a daily basis. There is a rich literature on repeated games, which formalizes folk-theorem type results, in which producers often can play collusive looking outcomes in repeated setting which secure them above-Cournot profits. These results are sensitive to assumptions such as observability of past actions and the discount factor. It would be of interest to see what type of discount factors are needed to reverse the 'forward markets are welfare enhancing' results in this literature. Producers in the Allaz (1992) model do not have a commitment device to stay out of the forward market, which essentially reduces their profitability in the overall game. A repeated game setting may provide a way for producers to commit to keeping their forward positions to a minimum, thus reversing some of these results.[13]

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[12] Bulow, Geneakoplos and Klemperer (1985) warn, however, that assumptions of linearity on the demand often produces strategic substitutes, but that this may no longer be true if demand is constant elasticity or nonlinear.

[13] There is a large literature on the commitment value of contracts, see e.g. Aghion and Bolton (1987) and Dewatripont (1988) for early contributions. Most of this literature criticizes the use of Pareto-dominated equilibria at later stages in a multi-stage game in order to select Pareto-superior equilibria in the overall game. If agents can renegotiate from a Pareto-dominated equilibria to some other equilibrium then the selection of the Parto-superior equilibrium is in question. It is suggested that selected equilibria be renegotiation-proof.

2.2.2. Applications

von der Fehr and Harbord (1992) and Powell (1993) are early studies that include contracts, and examine their impact on an imperfectly competitive electricity spot market, the U.K. pool. von der Fehr and Harbord (1992) focus on price competition in the spot market with capacity constraints and multiple demand scenarios. They find that contracts tend to put downward pressure on spot prices. Although, this provides disincentive to generators to offer such contracts, there is a countervailing force in that selling a large number of contracts commits a firm to be more aggressive in the spot market, and ensures that it is dispatched in to its full capacity in more demand scenarios. They find asymmetric equilibria for variable demand scenarios where such commitment is useful. Powell (1993) explicitly models recontracting by Regional Electricity Companies (Recs.) after the maturation of the initial portfolio of contracts set up after deregulation. He adds risk aversion on the part of Recs. to the earlier models. Generators act as price setters in the contract market, but compete in a Cournot equilibrium in the spot market. The Recs. set quantities in the contract market. He shows that the degree of coordination has an impact of the hedge cover demanded by the Recs., and points to a 'free rider' problem which leads to a lower hedge cover chosen by the Recs. Batstone (undated) considers the implications of strategic behavior on part of risk-neutral generators faced with cost uncertainty, who contract with risk-averse consumers maximizing mean-variance utility. He shows that in equilibrium generators have an incentive to increase the variance in the spot market price to extract a larger forward premium, and increase profits by selling more contracts.

Newbery (1998) analyzes the role of contracts as a barrier to entry in the England and Wales electricity market. Newbery extends earlier work by modeling equilibria in supply functions in the spot market. For tractability he assumes constant marginal costs, which allow him to derive analytical solutions to the spot supply functions. He models risk-neutral consumers with a similar market structure as in Powell. Newbery shows that if entrants can sign base load contracts and incumbents have enough capacity, the incumbents can sell enough contracts to drive down the spot price below the entry deterring level. Newbery shows that this could result in more volatile spot prices if producers coordinate on the highest profit SFE. Capacity limits however may imply that incumbents cannot play a low enough SFE in the spot market and hence cannot deter entry. Green (1999) extends Newbery's model including linear marginal costs. An interesting result is that when generators compete in SFEs in the spot market, an assumption of Cournot conjectural variations in the forward market implies that no contracting will take place unless buyers are risk averse and willing to provide a hedge premium in the forward market.[14] The author points out the this is a function of linear SFEs derived in this study, and not a general result for SFEs. Lien (2001) extends these results by explicitly modeling entry into these markets. He shows that forward sales can deter excess entry, and increase economic efficiency and long-run profits of a large incumbent firm faced with potential entrants.

2.3. Transmission Pricing and Design of Transmission Capacity Rights

The role of the system operator in providing open-access to the transmission network and pricing scarce transmission resources (as per FERC Order 888, and more recently FERC Order 2000), and to its extent of involvement in energy and other unbundled energy product markets has been a hotly debated issue over the past decade.[15] In a competitive market with centralized dispatch, locational prices are calculated at every node in the network (Schweppe et al., 1988). Congestion rent is then just the difference in locational prices between any two locations. Hogan (1992) shows that if transmission rights are financial rights to these locational price differences then this maximizes the value of the network. Under this paradigm, he proves revenue sufficiency of the system operator who provides access, i.e. the merchandizing surplus resulting from selling and buying power at nodal prices will cover the payments to transmission rights holders. The natural type of transmission rights that go with this scheme are point-to-

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[14] This result can also be understood in terms of Bulow et al.'s results. In Green's model, a particular firm's contract position has no effect on its competitor's spot market strategy, which means that there is not strategic substitutes effect.

[15] See among others, Hogan, 1992, 1993, 1994, 1995, 2000a and 2000b; Wu et al., 1996; Chao and Peck, 1996, 1997 and 1998; Oren, 1998; See Boucher and Smeers (2000) for a review of the various equilbrium concepts under perfect competition, and Daxhelet and Smeers (2001) who consider market power in the energy market using variational inequality formulations.

point rights (see Harvey, Hogan and Pope, 1997). These rights entitle the holder to the difference in locational prices between two points specified in the right. An important consequence of having point-to-point transmission rights is that a simultaneous feasibility test is required to determine if a set of rights is among those that are revenue sufficient. Another important aspect is that these rights can be defined as forward contracts or as options. If the equilibrium outcome is such that the some generators need to run out of merit, and some transmission line is constrained in the opposite direction of their flow to the point of withdrawal, then the value of these rights at settlement will be negative. Forward point-to-point rights can therefore have negative prices at the time of contracting if it is expected that for a major part of the time they will result in negative congestion rents or payments to the ISO. If rights are defined as options instead, the holder need not exercise them. This has consequences on revenue sufficiency of the system operator and the set of feasible rights that can be issued, and consequently, the set of transactions that can be fully hedged. There is also concern that a market in point-to-point rights will not be liquid enough to support bilateral trading in forward markets, and any uncertainty about which information is revealed as the settlement time is approached will need to be settled by the system operator by reconfiguring the entire set of rights that have been issued (see Oren et al., 1995). The influence of generator behavior on the market value of financial transmission rights has also received attention.[16] The prime example of a non-mandatory pool with point-to-point congestion rights is the PJM Interchange market.

For some of the proposed markets in the U.S. there are proposals that call for flow-based transmission rights (also called flowgate rights or FGRs; see Chao and Peck, 1996 and 1997; Chao et al.,

[16] Using Cournot assumptions, Oren (1997) argues that generators at supply nodes will have enough market power to capture the entire market value of 'passive' or financial transmission congestion contracts using two and three node examples. He argues that with 'active' or physical rights, and parallel trading in energy and transmission markets, such abuse of market power will be limited; Stoft (1997) argues to the contrary, and suggests that financial rights do mitigate market power under slightly different assumptions; Also, see Oren (1997b); Oren (1997c); and Stoft (1999) for further analysis using Cournot assumptions. Berry et al. (1999) use one and two-parameter supply functions and provide evidence that generators may be able to capture part of these rents. Joskow and Tirole (2000) provide a comprehensive analysis of how the allocation of transmission rights affects markets with generator and consumer market power. They find that the extent of the effects depends on the microstructure of the transmission rights markets and the distribution of market power. They find that purely physical rights have worse welfare properties than financial rights, but introducing a use-or-lose feature (which prevents withholding of physical capacity, but still honors the financial entitlement of the right) may help alleviate some of these adverse properties.

2000). The idea is that in any electricity network only a small number of transmission lines are expected to be congested, and if forward markets are established only for these commercially significant flowgates they will be highly liquid and provide adequate price signals to internalize network externalities[17]. This type of scheme also facilitates bilateral forward contracting. If a bilateral transactions needs to be hedged the parties involved can buy a known quantity of all commercially significant flowgate rights based on power distribution factors (these give the impact of any transaction on these flowgates and depend on the physical configuration of the network). Such a system can also support a more decentralized system with private parties involved in providing hedges to transactions by offering point-to-point transmission rights while purchasing flowgate rights to cover their positions.[18]

Proponents in favor of flow-based rights argue that the quantity of flowgate rights depend only on the physical capacity of the network, and thus can be determined accurately and is stable. Also, if flowgate rights are issued as options (in that counter-flow commitments are not considered when determining the quantity of rights issued) the set of transactions that can be hedged is greater than that allowed by point-to-point rights. Counter-arguments are that both the distribution factors (which determine the settlement rule for flowgate rights) and the line capacities themselves are subject to stochastic fluctuations depending on network conditions and other factors such as weather. Also, there is some disagreement as to what is a reasonable quantity of rights would be needed for liquidity in these markets (see Hogan 2000; Oren 2000a; Oren 2000b; Ruff 2000a, and Ruff 2000b). Although the debates surrounding this issue discuss the uncertainty in the spot outcome due to uncertain demand and network

[17] Chao et al. (2000) also propose that flowgates that are not expected to be commercially significant often can be bundled together in 'junk bundles' and shares of these can be traded along with the commercially significant FGRs.
[18] Such flow-based rights with scheduling priority are also supported for inter-control area management of congestion where price-only based schemes (such as those proposed by Cadwalader et al., 1999) may result in infeasible dispatch for the overall system (see Oren and Ross, 2000).

conditions, and forward contracting, no modeling effort has been forthcoming yet that incorporates all these aspects.[19]

Markets for transmission capacity have some characteristics that have been studied in the divisible-good auctions literature. Wilson (1979) analyzes a divisible-good auction where bidders bid for a share of the item on sale. He shows that there can be some collusive looking equilibria in a uniform price auction where bidders shade their demands and prices are low (also see Back and Zender, 1993; Wang and Zender, 1995). The number of competitors has a large impact on the bidding strategies, and this could have implications for the choice between point-to-point rights and flowgate rights. In a large network there will be many point-to-point rights that the system operator will auction off in a single auction. If bidders separate themselves, and few bidders compete for any single right, this could lead to low prices in the forward auction.

3. Formulation

Our formulations try and capture several aspects of current electricity market designs that have been previously modeled in isolation. We focus on zonal aggregation in the forward market in the presence of network uncertainty and market power. Studies with market power usually consider single-settlement systems, while the literature modeling interactions between spot and forward markets does not consider transmission constraints. Since zonal aggregation is proposed to facilitate forward trading by spatial aggregation, modeling network uncertainty is essential for an understanding of its implications.

As our focus is on understanding the mechanisms that drive our results, we analyze the problem with the help of several illustrative examples on simple two- and three-node networks. For the two-settlement cases, we formulate the problem as a two period game. In period 2, we model a spot market

[19] Smeers (2001) provides a comprehensive analysis of these proposals under the assumption of no market power. Smeers analyzes the various proposals using the yardstick of market completeness, and finds that none of the proposals provide financial market completeness in the way commonly assumed in financial models.

where generators use a Cournot conjectural variation.[20] We assume that generators take transmission prices as given and do not try to game the transmission system (Hobbs, 2001, and Smeers and Wei, 1997a make such an assumption). In all our examples, the spot market is organized at a nodal level.[21] There is a probability *r* that one of the transmission links will be binding in the spot market. In period 1, we model a forward market in which this transmission constraint is ignored, and the nodes are aggregated into a single zone over which there is a uniform price. Generators can enter into contracts in this period which are settled in period 2.

In a two-settlement system it becomes necessary to accurately describe the commodity, or the commodity price in case of financial contracts, underlying the forward contract. In a market with centralized dispatch, there is a single price in the forward market as transmission constraints are ignored in this market. To begin with, we assume that the spot market is a residual market. This means that the forward price is binding on energy delivered at any location within a zone, and that residual transactions are settled at nodal prices. This implies that there will be fewer forward prices than spot prices in the congested state, and that forward prices for different nodes within a zone will be equal. This will lead to arbitrage possibilities if the direction of congestion can be easily predicted. We analyze the extent to which generators participating in the physical market can take advantage of this system.

We consider two sets of cases. For one set of cases (reported as D1a in the results), we assume that the commodity price being traded is the demand-weighted average price in the spot market. In the presence of speculators who trade between the markets, the forward price will converge to the demand-weighted expected spot price (assuming risk neutrality and zero interest rates), and this fact is used to determine forward prices. In our examples, we find that this model predicts relatively small aggregate positions in the forward market.[22] There seems to be ample empirical evidence that generators cover a

[20] We are not aware of any study that derives a general supply function equilibrium in presence of a transmission constraints.
[21] Another interpretation is that congestion at the intra-zonal level is also considered and priced if there is a zonal forward market.
[22] This may change, although to a small extent, with the introduction of risk-aversion in the model.

large portion of their spot sales under forward contracts. There is also evidence that financial derivatives markets in electricity are generally illiquid, and trading in these markets has been much less than in comparative markets for other commodities. Therefore, in a second set of cases (reported as D1b in the results), we explore a physical market in which the forward contract is priced assuming that all demand shows up in the forward market, and is aggregated to determine the forward price. This case can be seen as a purely physical market, because in the presence of speculators who could arbitrage between forward and spot markets, such a system would not work.[23] This essentially relaxes the no-arbitrage condition, and provides generators with the opportunity to indulge in intertemporal price discrimination, and extract a strategic premium in the forward market.

The relaxation of the delivery requirement in a zonal forward contract favors generators located in one portion of the network, and penalizes generators located in another portion when congestion patterns are predictable. In order to analyze whether natural incentives for strategic forward trading exist despite this asymmetry, we consider a case where the forward market has a delivery requirement. Essentially, as electricity traded in the forward market is delivered at different locations in the network, this amounts to imposing an ex-post spot transmission charge on forward transactions if there is congestion in the spot market (these cases are reported as D2a and D2b in the results).

In the case of separated markets, there can be multiple forward prices, one corresponding to each node in the network. In keeping with the above framework, for cases D3a and D4a, we assume that speculators eliminate any differences in forward and spot prices, and so there is one forward contract per node, which is settled financially at the respective nodal price. Forward prices at all nodes will converge to respective spot prices in these cases as well. For cases D3b and D4b, we assume that all demand shows up in the forward market, and this is used to determine forward prices at the nodes (even though transmission constraints are ignored there can be multiple prices in such systems as is explained below). We analyze the following cases (a detailed description of each case follows):

[23] This also assumes that demand behaves non-strategically.

Case A. *Cost Based Economic Dispatch.*

Case B. *Single-settlement – Centralized Market*.

Case C. *Single-settlement – Separated Markets*.

Case D. *Two-settlement System for Electricity* (Zonal Forward Market).

D1. Residual Centralized Spot Market.

D2. Centralized Spot Market and Transmission Charges for Congestion Causation (delivery requirement).

D3. Residual Separated Spot Market.

D4. Separated Spot Market and Transmission Charges for Congestion Causation (delivery requirement).

Case A. This is the welfare maximizing[24] outcome and will be the solution to:

$$\text{(A)}\quad \begin{aligned} & p_i^A = MC(q_i) \quad \textit{for all nodes with generation}, i \\ & p_j^A = p_j(D_j) \quad \textit{for all demand nodes}, j \\ & \sum_i q_i = \sum_j D_j \\ & \sum_i \beta_{a,i}^c q_i = \bar{f}_a^c \quad \textit{for constrained line } a \\ & p_j = p_i + \sum_a \beta_{a,i} \lambda_a^c \quad \textit{for all nodes } i \textit{ and hub } j \, (i \neq j) \end{aligned} \qquad (1)$$

where, p_i, is the price at node i (we suppress the superscript for the state on energy prices and quantities), q_i is the production at node i (it is assumed that each firm has a single plant), D_j is demand at node j, $\lambda_a{}^c$ is the multiplier associated with link a[25] in state c, $c \in \{1, 2\}$ an index set of states, $\beta_{a,i}$ is the power transfer distribution factor or the amount of power that will flow over this line when 1 unit of power is transferred from node i to a reference node, and $\bar{f}_a^c$ is the capacity of this link in state c.

[24] As stated above, we use the sum of consumer and producer surpluses as a welfare measure.
[25] In our examples we assume that only the line between nodes 1 and 2 is congested.

Case B. In this case, we simulate a centralized market outcome with generators behaving à la Cournot (see Hobbs, 2001). In a centralized market model, the system operator sets generation and demand so as to maximize gains from trade, and transmission prices are set equal to the difference in nodal prices. We assume that generators take transmission prices as given. The equilibrium can be modeled as a two stage game. In the second stage of this game, the system operator arbitrages any differences in energy prices that are not based on cost, such that in the resulting equilibrium, there is no spatial discrimination in energy prices, i.e. the price difference between two nodes is exactly equal to the transmission charge for transferring energy between the two nodes. In the first stage, generators anticipate this arbitrage and compete in a Cournot-Nash manner. Each generator will solve the following constrained optimization problem in a centralized market.

$$\textbf{(B)} \qquad \begin{aligned} &\underset{q_i}{Max}\,\Pi_i = p_i q_i - C(q_i) \\ &p_j = p_i + \beta^c_{1-2,i}\lambda^c \quad \textit{for all nodes i and hub } j\,(i \neq j) \\ &\sum_i q_i = \sum_j D_j \end{aligned} \qquad (2)$$

The two first order necessary conditions (FONCs) along with the constraints of the problem, and the flow constraint from equation set (1), if binding, will determine the market outcome in this case.

Case C. In this case, the system operator conducts an auction for transmission capacity and does not get involved in the energy market (see Smeers and Wei, 1997a; Daxhelet and Smeers, 2001). Generators behave à la Cournot in a bilateral market, and then purchase transmission service from the system operator. For tractability, we assume that generators reveal their true willingness to pay for transmission capacity (their opportunity cost). This outcome can have spatial price discrimination as generators may set quantities in such a way that the price difference between nodes is different than the corresponding transmission charge. The system operator provides transmission service to the network assuming it cannot affect transmission prices. Each generator will solve the following optimization problem:

$$\textbf{(Cg)}\quad \begin{aligned} &\underset{s_{ij}}{Max}\,\Pi_i = \sum_j (p_j(s_{ij} + \sum_{k\neq i} s_{kj}) - w^c_j)s_{ij} - C(q_i) + w^c_i q_i \\ &(\theta_i):\ \sum_j s_{ij} = q_i \end{aligned} \qquad (3)$$

where s_{ij} is the amount of the bilateral transaction between the generator at node i and demand at node j and θ_i is the multiplier on the balance constraint. The system operator in turn solves a linear program of the following form:, assuming that it cannot affect transmission prices, w^c_j:

$$\textbf{(CG)}\quad \begin{aligned} &\underset{y_j}{Max}\,R^c_S = \sum_j w^c_j y^c_j \\ &(\lambda^c):\ \sum_j -\beta^c_{1-2,j} y^c_j \leq \bar{f}^c_{1-2} \end{aligned} \qquad (4)$$

where, w^c_j are transmission prices and y^c_i is defined as transmission service from the hub to node i in state c. In order to determine the equilibrium the first order conditions of the generators and the system operator are aggregated. A market clearing condition is added which equates the quantity of transmission services requested by generators to the quantity offered by the system operator at each node in the network given by:

$$\textbf{(MC)}\quad y^c_j = \sum_i s_{ij} - q_j \ \textit{for all nodes } j \qquad (5)$$

Case D1. In this case, the system operator operates a forward market but ignores congestion in this market. Any transactions in this market do not pay transmission charges in the spot market. Residual transactions made in the spot market are subject to nodal prices in the spot market. This can be interpreted as a zonal pricing scheme with a single zone across the nodes of the system. The system operator operates a centralized spot market. Generators will solve a 2 period problem in this case. In the second period, generators will maximize profits given their forward commitments:

$$\textbf{(D1)}\quad \begin{aligned} &\underset{q_i}{Max}\,\Pi_i = p^f f_i + p_i(q_i - f_i) - C(q_i) \\ &p_j = p_i + \beta^c_{1-2,i}\lambda^c \quad \textit{for all nodes } i \textit{ and hub } j\ (i \neq j) \\ &\sum_i q_i = \sum_j D_j \end{aligned} \qquad (6)$$

As in Case B, we can collect first order conditions and solve for an equilibrium numerically if the forward positions are given. In our examples, we assume that the congestion pattern is easily predicted, and therefore we can solve the equilibrium conditions for this case analytically (after dropping the complementary slackness conditions). This yields prices and quantities in terms of the forward positions, f_i, of the two generators.

In order to calculate an equilibrium of the two-settlement system, we employ the notion of a subgame perfect Nash equilibrium (SPNE) (see Fudenberg and Tirole, 1996). This says that in period 1, generators will correctly anticipate the reactions of all the agents moving in period two. The generators will therefore solve an expected profit maximization problem in period 1 (we assume that generators are risk-neutral), subject to equilibrium constraints in the forward market, if any, and using the functions derived for the spot market variables.[26] For the case with speculators, it is assumed that the forward market price will be the demand-weighted average price in the spot market. This creates nonlinearity in the first order conditions, and the solution has to be obtained numerically via a grid search.

Case D2. In this case, we assume that there is a delivery requirement on forward transactions. This implies that all transactions that are dispatched in the spot market are charged the spot transmission charge (see Chao et al., 2000b). This provides incentives for generators to avoid what is called a DEC game in markets where such aggregation is done in the forward market, e.g. the now defunct California PX market. Generators in such markets have an incentive to over-schedule in the day ahead market and then get paid for congestion relief in the real time market, in essence, get paid for not producing or for shifting their production to the import zone.[27] In a centralized market, it becomes necessary to decide on a

[26] In general, the generator's problem will be non-convex due to the complementary slackness conditions imposed in the spot market equilibrium. As mentioned earlier, if congestion patterns are easily predicted these can be dropped.

[27] This payment is made in the balancing (or residual) market, where generators submit price-quantity pairs of adjustment bids, called INCS and DECS, which specify the prices at which the generator is willing to buy back scheduled power, or raise its generation, respectively. When generators who are required to buy back power can charge a negative price for it, both INCS and DECS can get paid in such a system. However, even if the DEC payment is positive, i.e. a generator has to buy back the power it scheduled on the export side, a generator who

hub which establishes the spot transmission charge. Keeping in line with our earlier assumption for the settlement price for a forward contract, we use the demand-weighted average price as the hub price. Generators solve the following optimization problem in the spot market:

$$\textbf{(D2)}\quad \begin{aligned} &\underset{q_i}{Max}\,\Pi_i = p^f f_i + p_i(q_i - f_i) - C(q_i) - f_i(p_{hub} - p_i) \\ &p_j = p_i + \beta^c_{1-2,i}\lambda^c \quad \textit{for all nodes } i \textit{ and hub } j\,(i \neq j) \\ &\sum_i q_i = \sum_j D_j \end{aligned} \qquad (7)$$

where, p_{hub} is the hub price.

As the hub price introduces nonlinearity in the equilibrium conditions, we cannot solve for the quantities and prices in terms of the forward positions analytically. Instead, we conduct a grid search to determine the optimal forward positions by numerically tracing the reaction functions in the forward market for both subcases. For the subcase with speculators, the hub price also serves as the settlement price for forward contracts.[28]

Case D3. This case is similar to case D1 with the change that the spot market is separated (as in Case C). Generators will have bilateral forward commitments in this case and will solve the following optimization problem in period 2 (the spot market):

$$\textbf{(D3g)}\quad \begin{aligned} &\underset{s_{ij}}{Max}\Pi_i = p^f(\sum_j s^f_{ij}) + \sum_j (p_j(s_{ij} + \sum_{k\neq i} s_{kj}) - w^k_j)(s_{ij} - s^f_{ij}) - C(q_i) + w_i q \\ &(\theta_{i_i}):\ \sum_j s_{ij} = q_i \end{aligned} \qquad (8)$$

The grid owners problem remains the same. Again, prices and quantities in each state can be calculated in terms of the forward positions and the generators will solve an expected profit maximization problem in period 1 anticipating the spot market equilibria.

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controls resources on both sides of the constraint can make a profit by getting paid for the INC more than it pays back for the DEC.

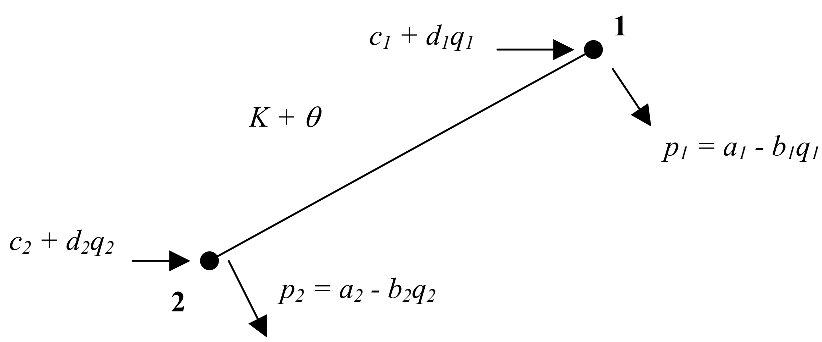
Case D4. This case is similar to D2 above with the change that the spot market is separated (as in Case C). The difference is that bilateral forward transactions can be charged the spot transmission charge based on the delivery node. Generators will solve the following optimization problem in the spot market:

$$\begin{aligned} &\underset{s_{ij}}{Max}\,\Pi_i = p^f(\sum_j s_{ij}^f) + \sum_j (p_j(s_{ij} + \sum_{k\neq i} s_{kj}) - w_j^k)(s_{ij} - s_{ij}^f) \\ (\mathbf{D4g}) \qquad &\qquad -C(q_i) + w_i q_i - \sum_j (-w_i + w_j) s_{ij}^f \qquad (9) \\ &(\theta_i):\ \sum_j s_{ij} = q_i \end{aligned}$$

The grid owner's problem remains the same as in (4). Again, prices and quantities in each state can be calculated in terms of the forward positions, and the generators will solve an expected profit maximization problem in period 1.

4. Two-node Example

Consider the example in Figure 1 with a single generator at each node of a simple two-node network. Cost and demand functions are linear as indicated at each node. We assume there are two states of the world, one in which the network does not have any transmission constraints, and the other where the capacity of the line joining node 1 and 2 is K MW. The generator at node 1 is assumed to be low cost, and could run at output levels that the transmission line would not be able to sustain in the state of the world where this capacity limit is binding (see Table 1 for data).



[28] While it is not common that forward commodity contracts are settled at a floating price (as opposed to the price at

Figure 1. A Simple two-node network

Table 1. Parameter Values for two-node example

Parameter	Value
a_1, a_2	100
b_1, b_2	2
c_1, c_2	10
d_1	1
d_2	4
K	3
θ	Large
r	Variable

4.1. No Congestion (Allaz and Vila, 1993)

We first analyze an example with no congestion in the spot market (see Allaz and Vila, 1993).[29] This will give us a point of departure from the literature, and a basis for comparing how the presence of transmission constraints affects behavior in two-settlement systems with imperfect competition. We assume symmetric demands for the two nodes in the system. Therefore, Cases B and C will produce identical results. Also, because we assume no congestion in the spot market, Cases D1a to D4a will produce identical results (as will D1b to D4b). Thus, there will be only 4 sets of results in this situation.

Case A. In the optimum dispatch, marginal costs for both generators are equal to price which is determined by clearing the aggregate market for the two nodes (see equation set (1)). This gives the maximum surplus that can be generated in this market.

a fixed delivery point), this is common practice in electricity markets, e.g. the forward contract at the PJM Western hub is settled at a weighted price based on 100 nodal prices.

[29] This is the case when $r = \Pr\{\theta = 0\} = 0$

Cases B and C. In the single-settlement case, generators compete in a Cournot-Nash game. As there are no transmission constraints, each generator solves an simple unconstrained optimization problem (see problem (2) after substituting the market clearing constraint into the objective). The standard first order condition of equating marginal revenues, with respect to the residual demand curve seen by a generator, to marginal costs applies directly. These can be expressed as:

$$p(q_i + q_j) + q_i p'(\cdot) = C_i'(q_i)\ \forall i, j = 1,2\ (j \neq i) \tag{10}$$

where *p(q)* is the aggregate inverse demand function.

These equations can be used to derive the reaction functions of the two generators in this market, i.e. the optimal production quantity of a generator as a function of the other generator's production quantity. The equilibrium quantities can be calculated as the point of intersection of the two reaction functions. For our case of demands and marginal costs which are linear in quantity, the reaction functions are also linear, and will therefore result in a unique equilibrium (see Figure 2).[30]

The first order conditions (10) can be rewritten as:

$$\frac{p(\cdot) - C_i'(q_i)}{p(\cdot)} = \frac{s_i}{\varepsilon}\ for\ i = 1,2 \tag{11}$$

where $s_i = \dfrac{q_i}{q_i + q_j}$, is firm *i*'s share of total production, and $\varepsilon = -\dfrac{1}{p'(\cdot)}\dfrac{p(\cdot)}{q}$ is the elasticity of aggregate demand at the aggregate production quantity, *q*. The left hand side is called the Lerner index for firm *i*.

[30] For nonlinear demand functions, there may be cases (such as with convex demand functions) that one may have multiple equilibria in the spot market.

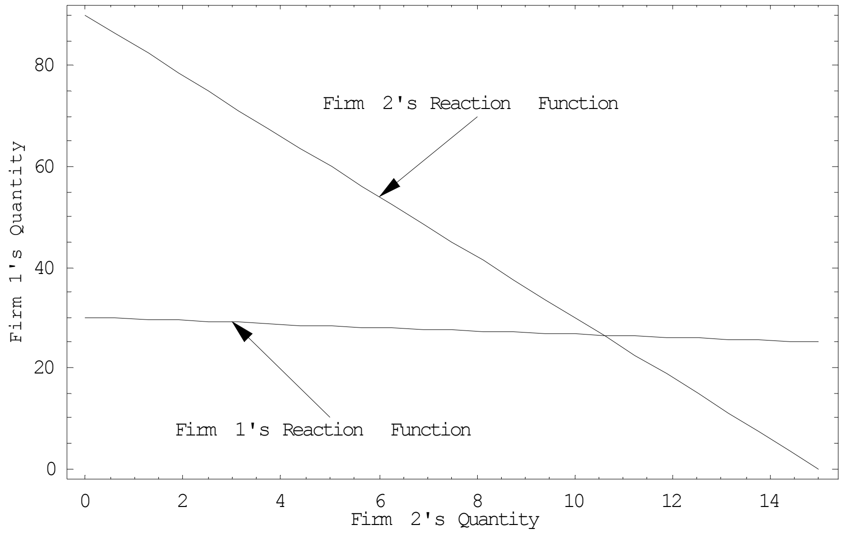


Figure 2. Reaction Functions for Cases B and C (no transmission constraints).

Cases D1a-D4a. The two-settlement system case is solved as a two period game. In the second period, generators will maximize profits given their forward commitments (see D11-D13; Cases D2a-D4a produce identical results as D1a due to our assumption of symmetric demands and no congestion). The first order conditions in this case will be a modified version for those of the Cournot case (see problem (2)).

$$p(q_i + q_j) + (q_i - f_i)p'(\cdot) = C_i'(q_i) \; for\, i, j = 1,2\,(j \neq i) \tag{12}$$

where f_i is the firm's forward position. Another way of deriving first order conditions is by marginal analysis, which looks at the benefit and cost of producing an additional unit setting the base level to the optimal production quantity:

$$\underbrace{p(q_i + q_j) - C_i'(q_i)}_{Marginal\ Benefit} + \underbrace{(q_i - f_i)p'(\cdot)}_{Marginal\ Cost} = 0 \; for\, i, j = 1,2\,(j \neq i) \tag{13}$$

This says that at the margin, the benefit of producing an extra unit, the price-cost margin p(·)-C′(·), should be equated to the externality cost of producing that unit which is the decrease in revenues from all infra-marginal units affected, $(q_i\text{-}f_i)\ p'(\cdot)$. As generators are expected to take short positions in the forward market, price cost margins in a two-settlement system will be smaller than in the Cournot case. Thus, forward commitments result in greater production in the spot market, and have the potential to increase the realized surplus as compared to the single-settlement case. This can be seen in the plot of the reaction functions which go outward for larger forward commitments (see Figure 3).

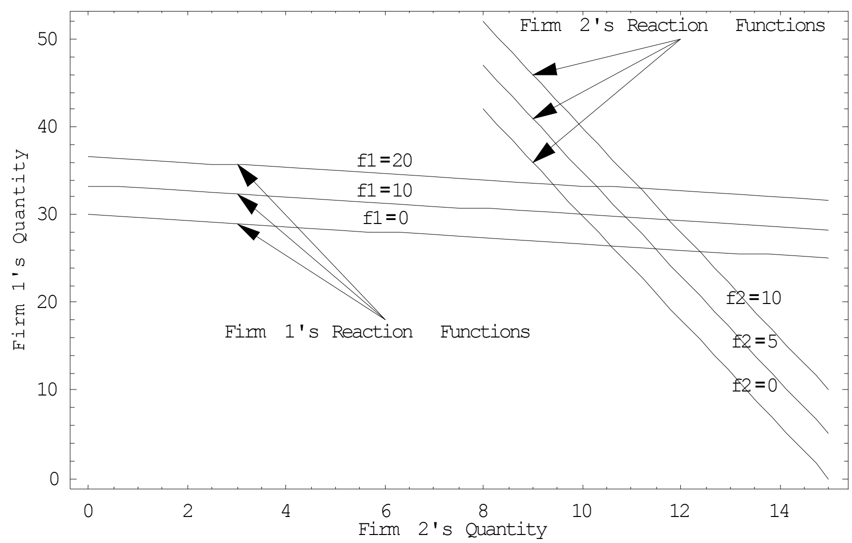


Figure 3. Reaction Functions in the Spot Market for Cases D1 to D4 (a and b) (no transmission constraints).

In a similar manner as equation (11), the first order conditions can be expressed as:

$$\frac{p(\cdot)-C_i'(q_i)}{p(\cdot)}=\frac{s_i'}{\varepsilon}\; for\, i=1,2 \tag{14}$$

where $s_i'=\dfrac{q_i-f_i}{q_i+q_j}$, is generator *i*'s adjusted share of total production. Therefore, the firm will behave as if it has a smaller share in the spot market than it actually has, and will be a more aggressive competitor, because it can free-ride on other participants in the market who share the burden of a price decrease.

In the forward market, the generators will solve an optimization problem with forward positions as decision variables (see problem (6), ignoring the transmission constraint). They will take into account how their forward position affects the equilibrium in the spot market (this can be done, either, by solving the spot market equilibrium analytically, or deriving the forward market equilibrium numerically, where the spot market equilibrium is solved as a subproblem).[31] As in Allaz and Vila, we assume that speculators arbitrage between spot and forward prices, therefore the forward price will be equal to the spot price. Writing the first order condition in the benefit-cost framework we get:

$$\underbrace{(p(\cdot) - C_i'(\cdot))q_i'(\cdot)}_{Marginal\ Benefit} + \underbrace{q_i p'(\cdot)(q_i'(\cdot) + q_j'(\cdot))}_{Marginal\ Cost} = 0 \ for\ i, j = 1,2\ (j \neq i) \qquad (15)$$

This says that the marginal benefit of hedging an extra unit in the forward market is the price-cost margin in the spot market for this level of forward positions multiplied by the sensitivity of the spot quantity to a unit change in this generator's forward position. The externality cost is the loss of revenue in the spot market from a decrease in spot price induced by the unit increase in the forward position (which is reduced through the increase in generator's own production quantity as well as its competitor's because equilibrium spot production quantities are a function of both forward positions). The entire quantity traded on the spot market, q_i, is affected due to equality between spot and forward prices imposed by the no-arbitrage condition (see Figure 4 for a plot of the reaction functions). One can group terms to get:

$$\big((p(\cdot) - C_i'(\cdot)) + q_i p'(\cdot)\big)q_i'(\cdot) + q_i p'(\cdot)q_j'(\cdot)) = 0 \ for\ i, j = 1,2\ (j \neq i) \qquad (16)$$

The first term in brackets is the Cournot first-order condition which will evaluate to zero at a forward position of zero. The second term evaluates to a positive value due the 'strategic substitutes effect' (see the discussion in Section 2.2.1), i.e. q'_j is negative. This means that generators will want to take positive (short) positions in order to commit to more aggressive behavior in the spot market, and this behavior is driven entirely by the fact that production quantities are strategic substitutes. As both generators take short positions, a prisoner's dilemma type of outcome occurs and both generators have lower profits and social welfare increases. A striking feature of the forward market equilibrium is that the aggregate forward position is a small fraction of the total spot production quantity (less than 20 percent).[32]

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[31] This requires that forward positions be observable.

[32] This is mainly because we only consider only two periods. Allaz and Vila show that as the number of trading periods increase to infinity all of the spot production quantity is hedged in forward contracts, and the resulting spot market outcome, corresponds to the competitive outcome. Allaz and Vila, however, do not quantify the proportion of the spot market quantity hedged in the forward market as the number of periods increase. Although, we use a

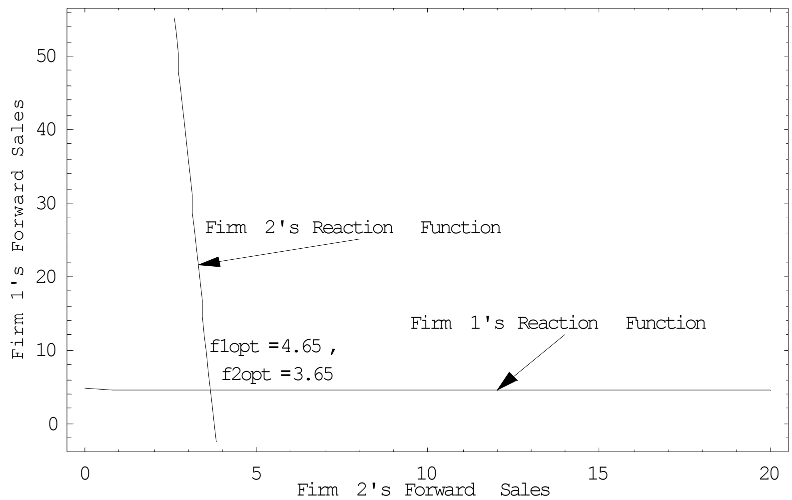

Figure 4. Reaction Functions in the Forward Market for Cases D1a to D4a (no transmission constraints).

Case D1b-D4b. Given that a no-arbitrage condition in a two period setting produces a small quantity of forward trading, in the current set of cases we explore the implications of relaxing the no-arbitrage condition. Electricity markets usually have physical markets that run in parallel to financial markets and these are run for only a few periods. Given that the market is non-competitive, the financial market is likely to be illiquid due to the fact that spot market outcomes can be manipulated by generators participating in the physical market. In the physical market, a market clearing mechanism is usually used to determine price. In the current set of cases, we assume that all of the demand shows up in the forward market and is aggregated to determine the forward price. This essentially gives the generators an extra degree of freedom to extract surplus from consumers. It remains to be seen how the more aggressive

specific example to quantify this proportion we have performed sensitivity analysis on the cost function and demand parameters that shows that the addition of a single trading period produces a relatively small quantity of forward trading.

behavior in the spot market as a result increased forward trading will affect total surplus generated in this market.[33]

For this set of cases, the two generators will have the same incentives in the spot market as compared to Cases D1a to D4a. However, in the forward market the generators can directly influence the forward price by changing their positions. There is an additional term in the first order condition reflecting the difference between forward and spot prices:

$$\underbrace{(p^f - p(\cdot)) + (p(\cdot) - C_i'(\cdot))q_i'(\cdot)}_{Marginal\ Benefit} + \underbrace{q_i p'(\cdot)(q_i'(\cdot) + q_j'(\cdot))}_{Marginal\ Cost} = 0 \ for\ i, j = 1,2\ (j \neq i) \tag{17}$$

The equilibrium results in a larger proportion of the spot production quantities being hedged in the forward market (see Figure 5). As a result, spot production quantities are higher for both firms as both generators take larger short positions in the forward market.

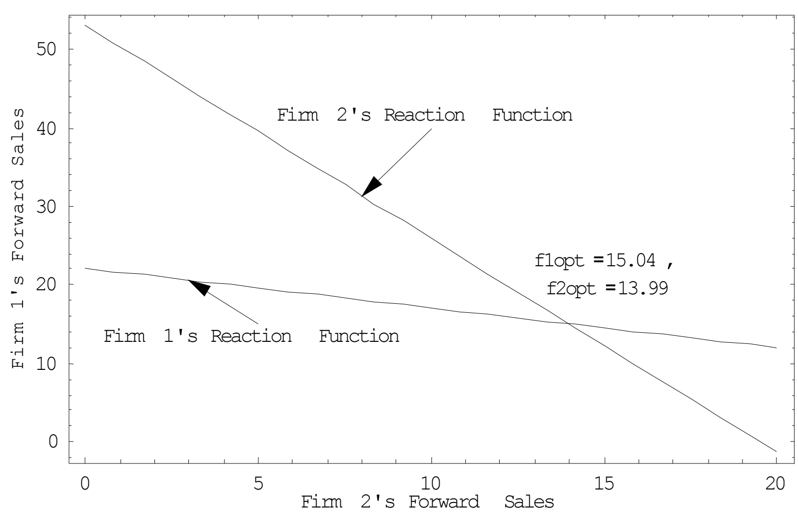

Figure 5. Reaction Functions in the Forward Market for Cases D1b to D4b (no transmission constraints).

[33] One can argue, that given an infinite number of trading periods where such a market-clearing mechanism is available to the generators, they can extract the entire surplus of the consumers and produce the competitive outcome quantity in the spot market.

4.2. Transmission Constraints

We now consider the case where the probability that the transmission line will have a constraining capacity is positive, i.e. there will be two states of nature in the second period, one in which the spot market is unconstrained, and the other where the transmission link between the two nodes will have a capacity of K units. We assume node 2 as the hub node, therefore the shift factors will be $\beta_{1\text{-}2,1} = 1$ and $\beta_{1\text{-}2,2} = 0$ for nodes 1 and 2, respectively.[34] We illustrate the impact of congestion by analyzing how the reaction functions and equilibria change as a function of congestion. Numerical results are reported for a probability of congestion, r = 0.05.[35]

Case A.

Unconstrained State: Results are the same as the Allaz-Vila (AV) example.

Constrained State: When the transmission line between nodes 1 and 2 has a small enough capacity, prices at the two nodes will not be equal. At node 1, where the cheaper generator is located, price is set such that the excess supply at this price is equal to the capacity of the transmission line. Similarly, at node 2 the price is set such that the excess demand at this price is equal to the imports from node 1, i.e. K units. The difference in prices is the transmission tariff charged to exports from node 1 (see equation set (1) with $\bar{f}_{1-2} = K$).

Cases B.

Unconstrained State: Results are the same as the AV example.

Constrained State: As mentioned before, in solving for the spot market equilibrium, we assume that the generators do not game the transmission system, i.e. they are price takers in the transmission market, and reveal their true willingness to pay for transmission services. We solve for this equilibrium assuming that

[34] A shift factor represents the fraction of power that flows over a particular transmission line if 1MW of electricity is sent from the node in question to the hub node.

the transmission link will be constrained in the direction 1→2 (cheap to dear).[36] This implies that the residual demand curve observed by the cheap (dear) generator is the original demand schedule at that node shifted right (left) by the capacity of the transmission link, K. The residual demand schedules that the generators face will therefore be insensitive to the quantity produced by the other generator (see Figure 6). The elasticity of demand in the residual market will be smaller in this case as the market is now disaggregated. Equilibrium prices will be lower at the exporting node and higher at the importing node as compared to the unconstrained state.

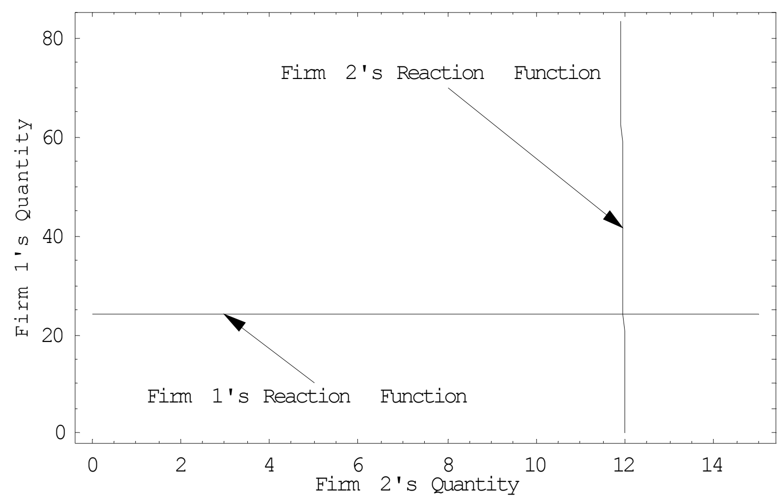

Figure 6. Reaction Functions in the Spot Market for Case B (Constrained State).

Case C.

Unconstrained State: Results are the same as the AV example.

Constrained State: In the separated market case, generators make bilateral sales to demand at the two nodes, and then request the system operator for transmission service. We again assume that the transmission link will be constrained in the 1→2 direction, and solve the combined KKT conditions of problems (3) and (4). In order to see the solution graphically, we use the observation that the amount of

[35] As an upper limit, we assume that intra-zonal congestion will be present in 200 of about 4000 peak hours.
[36] For larger networks, the equilibrium can be formulated as a complementarity problem (see Hobbs, 2001).

sales made by the generator at node 1 to demand at node 2 will differ from the amount of sales made by the generator at node 2 to demand at node 1 by K, the capacity of the link. Therefore, the solution of the optimization problem for generator 1 will only have s_{21} as a parameter and similarly for the generator at node 2. We therefore plot the reaction functions for a generator as a function of its competitor's production quantity conditional on its competitor's sales to demand at its own node (these essentially define sales to the other node). Unlike Case B, the reaction functions are now sensitive to the other generators production quantity even in the constrained state (see Figure 7).

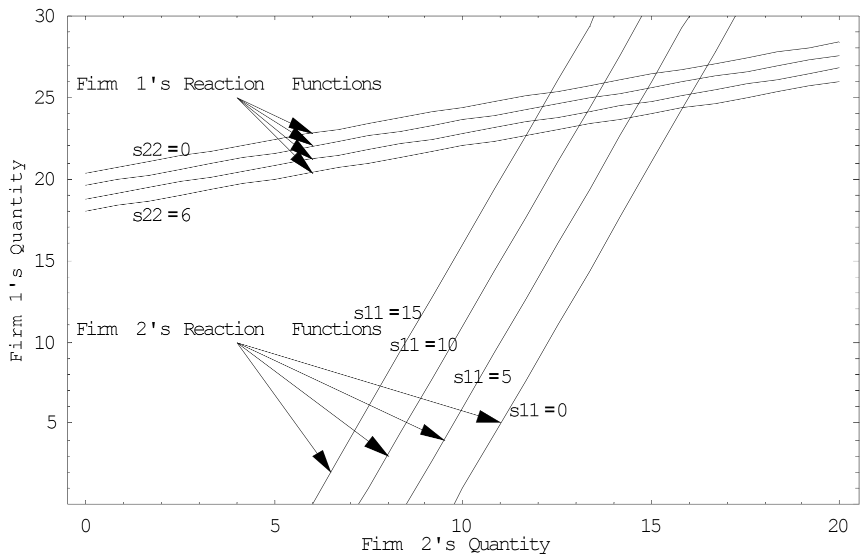

Figure 7. Reaction Functions in the Spot Market for Case C (Constrained State).

Case D1a. As in the AV example, we solve the two-settlement cases as two period games. There will now be two states of the world in the spot market. In this case, we assume that the commodity price being traded in the forward market is the demand-weighted average spot price. In the presence of risk-neutral speculators who can arbitrage between the two markets, the forward price will converge to the expected demand-weighted spot price (assuming zero interest rates).

Spot Market – Unconstrained State: Generators will have the same incentives as AV example (Figure 3).

Spot Market – Constrained State: We derive reaction functions for the constrained state in a similar manner as the AV example (using first order conditions of problem D instead of B). These will again be insensitive to the other firms quantity (see Figure 8). We note that in the constrained state a generator's reaction function will depend only on its own forward position as each generator operates in its own dis-aggregated market.[37]

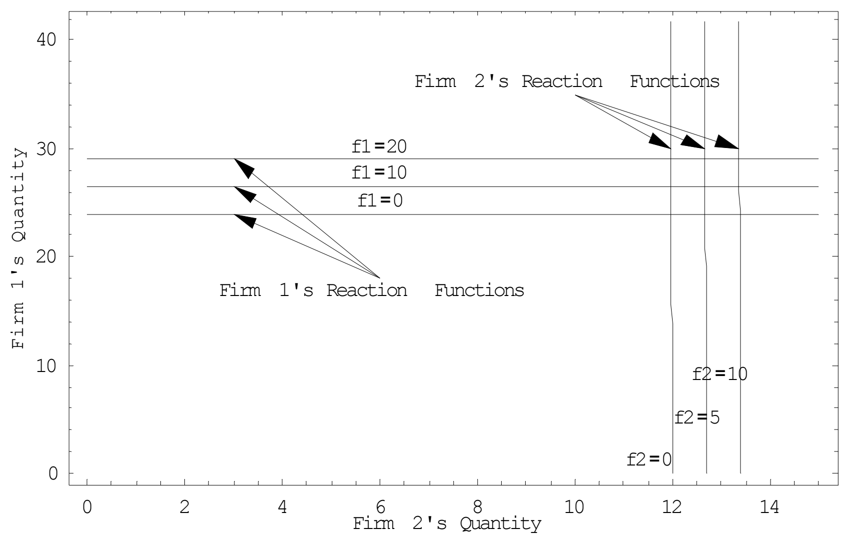

Figure 8. Reaction Functions in the Spot Market for Case D1a and b (Constrained State).

Forward Market: The profit function for generator *i* is now:

$$\Pi_i^f = p^f f_i + E\{(q_i(\cdot) - f_i) p_i(\cdot) - C_i(q_i(\cdot))\} \quad (18)$$

where the expectation is with respect to the random variable, θ, describing the state of the system (the system is in the constrained state with a probability r). To analyze the impact of congestion, we write the first order conditions for the generators (after grouping terms):

[37] This may prove useful in solving for such equilibria in larger networks, where the functions describing the relationship between spot quantities and forward positions could be approximated by performing simulations, and having the functions depend only on a generator's own forward position would greatly reduce the dimension of the problem. Prices over a network would depend on all forward positions.

$$
\begin{aligned}
&\underbrace{(p^{noK}(\cdot)-C_i'(\cdot))q_i'^{noK}(\cdot)+q_i^{noK}p'^{noK}(\cdot)(q_i'^{noK}(\cdot)+q_j'^{noK}(\cdot))}_{Original\ FONCs} \\
&\underbrace{+r\Big((p_{avg}^{K}(\cdot)-p_i^{K}(\cdot))+(p_i^{K}(\cdot)-C_i'(\cdot))q_i'^{K}(\cdot))-(p^{noK}(\cdot)-C_i'(\cdot))q_i'^{noK}(\cdot)\Big)}_{Marginal\ Benefit} \\
&+rf_i(p_{avg}'^{K}(\cdot)-p_i'^{K}(\cdot))(q_i'^{K}(\cdot)+q_j'^{K}(\cdot)) \\
&\underbrace{+r\Big(q_i^{K}p_i'^{K}(\cdot)(q_i'^{K}(\cdot)+q_j'^{K}(\cdot))-q_i^{noK}p'^{noK}(\cdot)(q_i'^{noK}(\cdot)+q_j'^{noK}(\cdot))\Big)}_{Marginal\ Cost} \\
&=0\ for\ i,j=1,2\ (j\neq i)
\end{aligned}
\tag{19}
$$

The first group of terms will evaluate to zero at the 'No Congestion' equilibrium. Three factors influence the direction of change in the level of forward trading as a function of congestion. The first effect is due to the fact that residual trading is at nodal prices. This produces an asymmetric effect on the two firms with the firm at the exporting node receiving a premium by trading in the forward market, and vice versa for the firm at the importing node (first term in brackets on line 2). The second effect, which is also asymmetric, is due to the presence of transmission constraints. Price cost margins are lower at the exporting node in the constrained state as compared to the unconstrained state, and vice versa for the importing node. The third effect is a combination of the fact that markets are segregated in the constrained state and the lack of the 'strategic substitutes effect' in that state. Essentially, the residual demand schedule is less elastic when markets are segregated, and therefore, $p^{K\prime} < p^{noK\prime}$. Also, $q^{K\prime} = 0$ in the constrained state. The net effect of these three factors is negative for both firms with a larger effect on the firm at the importing node (see Figure 9, where the reaction functions are plotted for various probabilities of congestion).

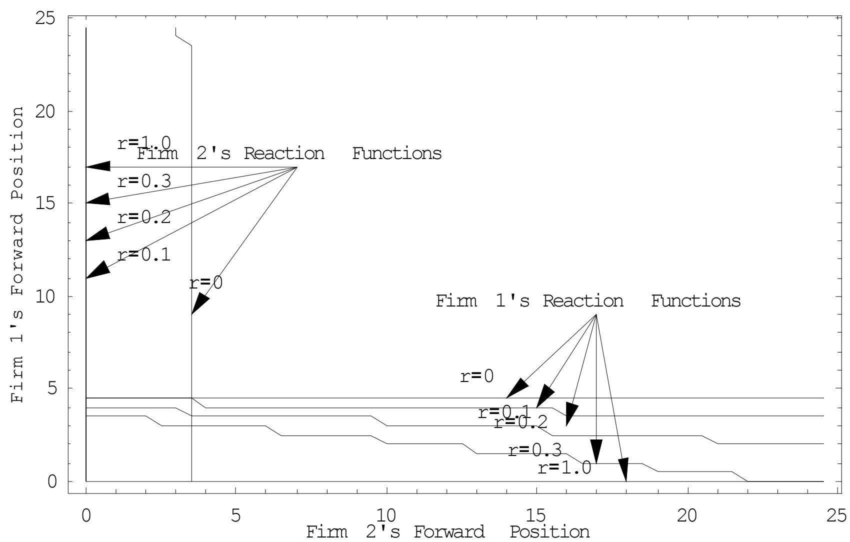

Figure 9. Reaction Functions in the Forward Market for Cases D1a for various Probabilities of Congestion, r.

Case D1b. In the previous case, we assumed that forward prices are set by risk-neutral speculators who arbitrage away any differences between forward prices and expected spot prices. In the current case, we assume that all demand shows up in the forward market, and we use market clearing conditions to determine the forward price. This implies that forward prices will not equal expected spot price for both the nodes, and there will be arbitrage opportunities between spot and forward markets.[38]

Spot Market – Unconstrained State: Generators will have the same incentives as in the AV example (see Figure 3).

Spot Market – Constrained State: The assumption of relaxing the no-arbitrage condition between forward and spot markets does not affect the generators' behavior in the spot market. Given some forward positions, the optimization problem solved by the generators is the same as in Cases D1a.

Forward Market: The only change in the first order condition from the previous case (see equation 19) is the addition of the strategic forward premium, which is positive for both firms. Now, the firm at the

[38] The forward price cannot equal both spot prices, because in the congested state the two nodes have different prices.

exporting node increases its forward position as a function of the probability of congestion, while the negative effect on the firm at the importing node is reduced, but not eliminated (see Figure 10).

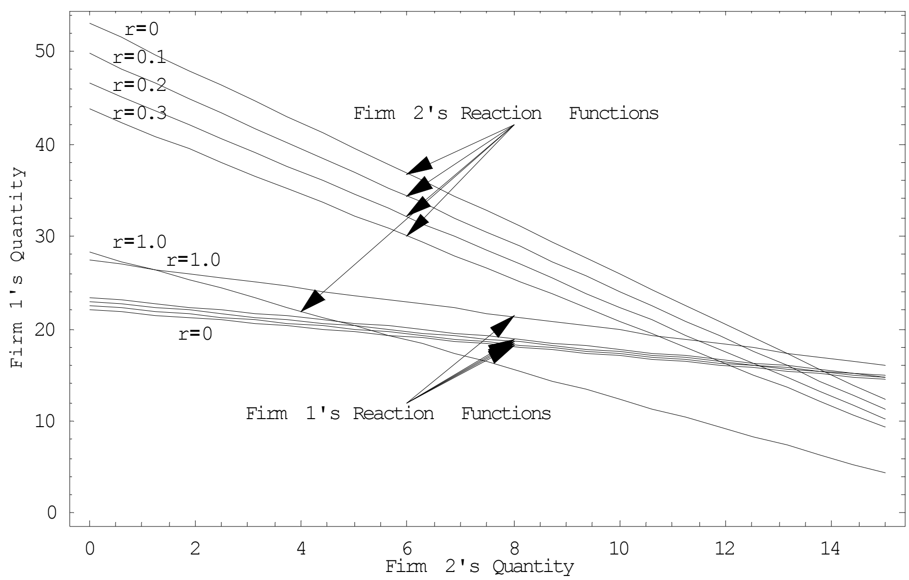

Figure 10. Reaction Functions in the Forward Market for Case D1b for various Probabilities of Congestion, r.

Impact on total forward positions

We now examine how these incentives affect the scheduled flow on line 1–2 in the forward market in the extreme case when $r = 1$ (see Table 2 Observe that the total forward sales do not change much for $r = 1$ as compared to $r = 0$. The same is the case with the spot market. However, the forward schedule for $r = 1$ is very skewed with the generator at node 1 selling 96.3 percent of total forward sales (it sold 51.8 percent for $r = 0$). This produces a flow of 12.81MW on line 1→2, which is much larger than its transmission limit of 3MW. This overscheduling of possibly congested lines is refered to as the DEC game in the literature (Chao et al., 2000b).

Table 2. Forward and Spot Market Outcomes for $r = 0$ and $r = 1$, Case D1a.

	Forward market						
State	Firm 1's position	Firm 2's position	Price at node 1	Price at node 2	Demand at node 1	Demand at node 2	Flow on line
$r = 0$	15.0	14.0	71.0	71.0	14.5	14.5	0.5
$r = 1$	26.6	1.0	72.3	72.3	13.8	13.8	12.8
	Spot market						
	Firm 1's quantity	Firm 2's quantity	Price at node 1	Price at node 2	Demand at node 1	Demand at node 2	Flow on line
$r = 0$	31.0	12.2	56.9	56.9	21.6	21.6	9.4
$r = 1$	30.7	12.1	44.7	69.7	27.7	15.2	3.0

The two two-settlement cases show that residual markets with zonal aggregation of forward prices, which essentially relaxes the delivery requirement in a forward contract, produces adverse effects in the form of the DEC game. Below, we analyze Case D2 where a spot transmission charge is imposed on all physical forward transactions, i.e. those that are delivered in the spot market.

Case D2a. In this case, the commodity price being traded in the forward market is still the demand-weighted average spot price, but physical transactions have to pay the difference between the nodal price at the delivery node and the hub price (this may be negative).

Spot Market – Unconstrained State: Same as case D1a as there is no congestion, and therefore, forward transactions are not charged any spot transmission charges.

Spot Market – Constrained State: We use the first order conditions of Problem D2 to plot the reaction functions for this case as a function of own forward positions (see Figure 11). The hub price introduces nonlinearity in the reaction functions in this case. However, for a given spot production quantity of a competitor, the optimal spot production quantity of the generators is increasing in the generator's own forward position.

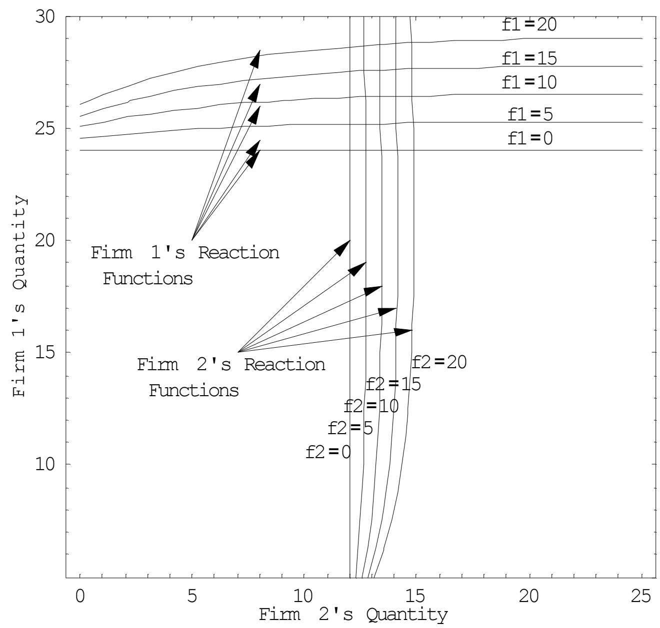

Figure 11. Reaction Functions in the Spot Market for Case D2a (Constrained State).

Forward Market: As the hub price introduces nonlinearity in the equilibrium conditions, we cannot solve for the equilibrium spot quantities and prices in terms of the forward positions analytically. To determine optimal forward positions, we conduct a grid search, and numerically trace the reaction functions in the forward market (see Figure 12). The first order conditions in the forward market show that the premium resulting from zonal aggregation without a delivery requirement is no longer present, and as a result forward positions are more symmetric, though declining in r, the probability of congestion[39]:

$$\begin{aligned}
&\underbrace{(p^{noK}(\cdot)-C_i'(\cdot))q_i'^{noK}(\cdot)+q_i^{noK}p'^{noK}(\cdot)(q_i'^{noK}(\cdot)+q_j'^{noK}(\cdot))}_{Original\ FONCs} \\
&\underbrace{+r\Big((p_i^K(\cdot)-C_i'(\cdot))q_i'^K(\cdot))-(p^{noK}(\cdot)-C_i'(\cdot))q_i'^{noK}(\cdot)\Big)}_{Marginal\ Benefit} \\
&\underbrace{+r\Big(q_i^K p_i'^K(\cdot)(q_i'^K(\cdot)+q_j'^K(\cdot))-q_i^{noK}p'^{noK}(\cdot)(q_i'^{noK}(\cdot)+q_j'^{noK}(\cdot))\Big)}_{Marginal\ Cost} \\
&=0\ for\ i,j=1,2\ (j\neq i)
\end{aligned} \tag{20}$$

[39] We do not calculate the optimal positions (which are negative) in this case as it is primarily our interest to show that they are not positive. Due to repetition, if generators have incentive to take long positions, such a system would not function effectively.

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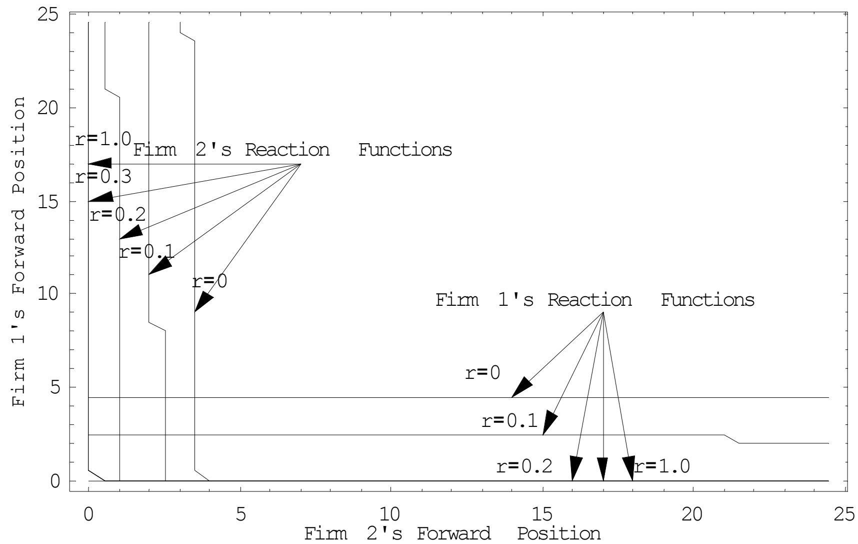

Figure 12. Reaction Functions in the Forward Market for Case D2a for various Probabilities of Congestion, r.

Case D2b.

Spot Market: The incentives in the spot market are the same as in Case D2a.

Forward Market: The corrected incentives in the forward market result in a more balanced schedule. Thus, there is a smaller flow on line 1–2 considering only the forward market schedule. Firm 1's optimal forward position is now *decreasing* in the probability of congestion, for a given forward position of Firm 2.

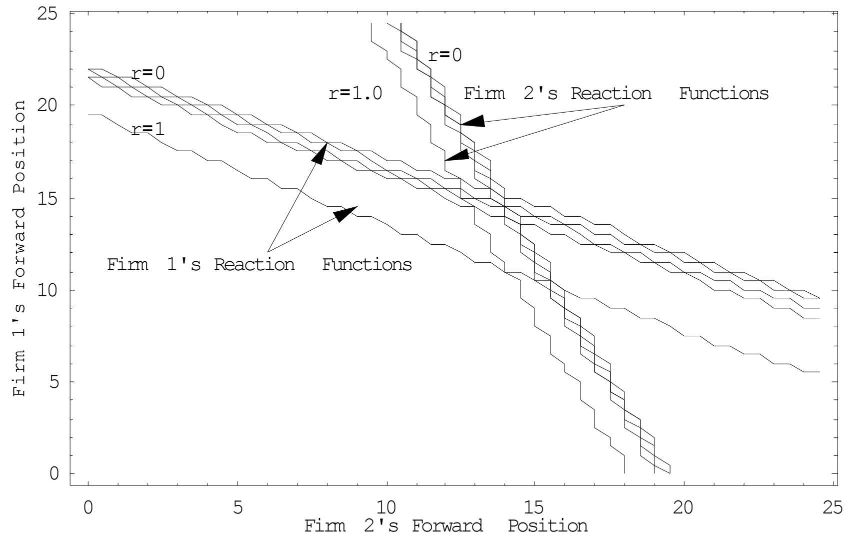

Figure 13. Reaction Functions in the Forward Market for Case D2b
for various Probabilities of Congestion, r.

One observation that can be made at this point is that forward coverage decreases as the probability of congestion increases. This seems to point to a spillover effect, in that there seems to be an indirect value to a more reliable network in terms of its ability to reduce market power. Even though congestion is rare, the possibility that a line may be congested produces incentives to reduce forward coverage, and thus, reduces the ability of the forward market to mitigate market power in the normal, i.e. uncongested state.

4.3. A Numerical Example

In this section, we present some numerical results for the two node network in Figure 1 (see Table 1 for parameter values). The probability of congestion is assumed to be 0.05 (see the Appendix for results). The optimal dispatch results in welfare levels of $2250 per hour and $2106 per hour in the unconstrained and constrained state, respectively (see column 6 of Table 4 for welfare levels). The single-settlement centralized dispatch results in welfare levels that are lower than the optimal dispatch in the amount of 7.8 percent and 5.1 percent, in the unconstrained and constrained state, respectively. Two-settlement systems are generally known to lead to more aggressive behavior on part of generators in the spot market, and it is expected that the two-settlement systems will make up some of the welfare loss due to market power. We observe that for this level of congestion, two-settlement systems continue to be welfare enhancing, reflecting the no congestion (AV) case. For the 'no-arbitrage' cases, consumers benefit because of the higher spot production to the detriment of generators, as in previous literature (see column 5 of Table 4 for consumer surplus levels, and columns 2 and 3 of Table 4 for generator profits). Profits for the generators show the prisoner's dilemma effect at work. Specifically, the combined profit of the generators drops from $1387 per hour for case B to $1365 per hour for Case D2a. The 'market clearing' cases have higher welfare increases due to larger coverage in forward contracts, however, consumer surplus is lower as compared to the 'no-arbitrage' cases because of the market clearing assumption used to set the forward price. Producers are able to extract as much as 26.7 percent of consumer surplus in case D1b (residual market with centralized dispatch) as compared to case D1a (in the unconstrained state).

In the optimal dispatch, price is $50 per MWh in the unconstrained state (see Table 5 for prices in the spot and forward market). In the constrained state, spot price at node 1 is $42 per MWh, while at node 2 it is$66 per MWh. In comparison, the price in the unconstrained state for case B is $63 per MWh, while it is $58 per MWh and $70 per MWh at nodes 1 and 2, respectively in the constrained state. In the 'no-arbitrage' two-settlement cases, prices in the unconstrained state are about $1 lower, while they are $6 lower in the 'market clearing' two-settlement cases than in case B. These results are also driven primarily by the amount of forward coverage which is much larger in the 'market clearing' cases. Forward prices in the 'market clearing' cases average $71 per MWh, with expected spot prices averaging $57 per.[40] While this difference seems quite large, and almost unsustainable in a repeated market, price differentials of a few dollars have been observed in the first year of the day-ahead and real-time California markets (Borenstein et al., 2001).[41]

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[40] The magnitude of the difference in forward and spot prices in the 'market clearing' case is related to our assumptions regarding the slope (elasticity) of the demand functions. In our three-node example, price differentials are smaller.

[41] Borenstein et al. calculate differentials between spot and day-ahead prices, so if day-ahead prices are higher their differentials are negative. This differential can also be interpreted as a risk premium. Interestingly, they also report positive price differentials of a few dollars in the Fall of the first year; these are not statistically significant in the second year. They also point out to inefficiencies that can come about in the system due to predictable congestion

The generation market in the example is asymmetric with 80 percent of spot market production at the exporting node for the optimal dispatch (see columns 8 and 9 of Table 6 for generation levels; Table 6 also shows sales and transmission flow levels). Demand in the constrained state is 8 percent lower as compared to the unconstrained state (this is the sum of columns 1 and 2). The generator at the exporting node is primarily responsible for exerting market power, reducing production by 33 percent for the single-settlement case. An interesting result for the two-settlement cases is that the generator at the importing node produces at higher levels than in the optimal dispatch case, because of its commitment in the forward market. This implies that though generators have incentives to be more aggressive in a two-settlement system some of the aggression is misplaced, and less efficient generators may be producing at higher levels than is socially optimal.

As mentioned above, a striking result is that in the 'no-arbitrage' cases, having one forward period yields on an average less than 15 percent contract coverage (see Table 7 for forward sales). The 'market clearing' cases, on the other hand, have contract coverage of around 68 percent. This points to the fact that in the presence of market power, the strategic incentives that generators have to contract in short-term forward markets play a big role in the outcome of these markets, perhaps dominating the risk-sharing aspects of these markets. The addition of the spot transmission charge has the desired result of reducing net flow on the transmission line in the forward market. One other significant result is that in case D3a, the generator at node 2 is long in the forward market at node1. This means that it prefers to be less aggressive as compared to the single-settlement case at this node. Increasing the probability of congestion seems to make this behavior more acute with both firms wanting to take long positions in the forward market. Welfare levels are usually reduced to levels lower than the single-settlement cases in such cases. This also has a considerable impact on the grid owner's revenue, which drops substantially

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across an inter-zonal interface (inter-zonal congestion is priced in the day-ahead market and an outcome of no congestion in the day-ahead market is a reflection of expectations of market participants, whereas in our model intra-zonal congestion is ignored as part of the market design).

between the residual and spot transmission charge cases. Long forward positions may mean that the grid owner may run a deficit in a residual market.

5. A Three-node Example

Electricity systems usually have networks with loop flow which often have different externality characteristics than radial networks. We now consider a three-node example representing of a simplified electricity system with loop flow (see Figure 14).

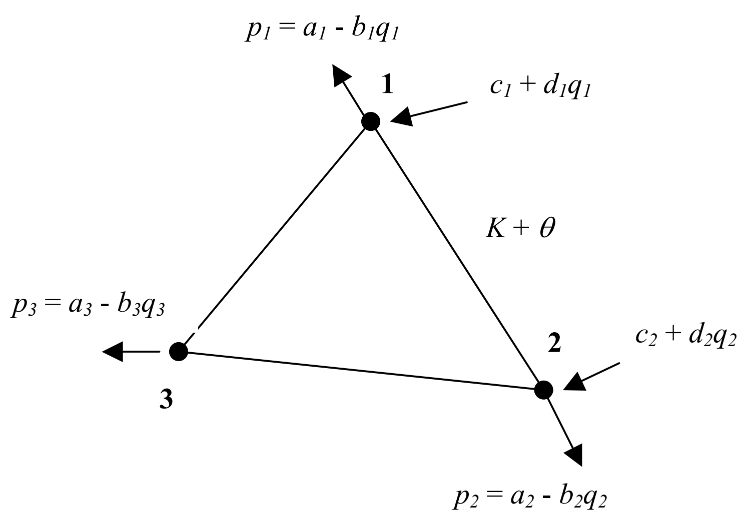

Figure 14. A Three-node Example

Table 3. Parameter Values for Three-node Example.

Demand Data		Supply Data		Other Data	
Parameters	Value	Parameter	Value	Parameter	Value
a_1	40	c_1	5	K	25
a_2	40	c_2	10	r	0.05
a_3	32	d_1	0.05		
b_1	0.08	d_2	0.10		

b_2	0.08
b_3	0.0516

5.1. Numerical Results

The three-node results mirror those obtained for the two-node case. As before, we find that forward markets are welfare enhancing for this level of congestion. Due to the assumed slopes of the demand functions in this case, differentials between forward and spot prices are smaller in this case as compared to the two-node case. Interestingly, long forward positions are again seen in some cases, and in Case D3a (separated residual market) this produces a deficit for the grid owner (see Table 8 to Table 11 in the Appendix).

6. Concluding Remarks and Future Work

In this paper, we model and analyze several electricity market designs currently adopted or proposed in the U.S., in the presence of network uncertainty and market power. Using the centralized dispatch single-settlement system as a benchmark, we analyze and compare the introduction of a two-settlement system with aggregation of nodes in the forward market. We find that when spot markets are residual markets (cases D1 and D3), welfare impacts of zonal aggregation are highly sensitive to the probability that a network contingency reduces the transmission capacity of an important line in the network. Using a duopoly model over simple two- and three-node networks, we show that this sensitivity comes from three factors affecting the incentives of generators participating in the forward market. The first effect is due to the fact that generators delivering electricity at different locations in the network trade at one price in the forward market, while residual trading is at nodal prices. This produces an asymmetric effect on the two firms with the firm at the exporting node receiving a premium by trading in the forward market, and vice versa for the firm at the importing. The second effect, which is also asymmetric, is due to the presence of transmission constraints. Price cost margins are lower at the exporting node in the constrained state as compared to the unconstrained state, and vice versa for the importing node. The third effect is a combination of the fact that markets are segregated in the constrained state and the lack of the ‘strategic substitutes effect' (see Bulow, Geneakoplos and Klemperer, 1985) in that state. The combined effect of these factors is that for even small probabilities of congestion, forward trading may be substantially reduced, and the market power mitigating effect of forward markets (as shown in Allaz and Vila, 1993) may be nullified to a great extent. We find that the imposition of a delivery requirement for the forward contract alleviates some of the incentive problems associated with zonal aggregation (cases D2 and D4). Essentially, as electricity traded in the forward market is delivered at different locations in the network, this amounts to imposing an ex-post spot transmission charge on forward transactions if there is congestion in the spot market. Though, this resolves the asymmetry in the treatment of forward transactions across a possibly congested line, we find that some reduction in forward trading persists due to the segregation of the markets in the constrained state and the absence of the 'strategic substitutes effect'. This points to an indirect value to a more reliable (lower probability of congestion or increased capacity) network in terms of its ability to reduce market power. Even though congestion is rare, the possibility that a line may be congested produces incentives to reduce forward coverage, and thus, reduces the ability of the forward market to mitigate market power in the normal, i.e. uncongested state.

In our analysis, we find that the standard assumption of 'no-arbitrage' across forward and spot markets leads to very little contract coverage even in the no congestion case. This seems to be at odds with empirical evidence that there is substantial contract coverage in electricity markets. In providing an alternative view of the market, we explore the implications of relaxing the 'no-arbitrage' assumptions, and for a set of two-settlement cases, assume that all of the demand shows up in the forward market and is aggregated to determine the forward price using a 'market clearing' condition. This essentially gives the generators an extra degree of freedom to extract surplus from consumers. This also re-establishes the incentives for generators to take short positions in the forward market, and we find higher levels of contract coverage in these cases.

In our examples, we considered a single-zone system and therefore ignored the impact of transmission contracts in the market outcomes. As the design of transmission contracts has been a topic of active debate over the past few years, and the impact of network uncertainty is an important component of the debate, extending our model to a multi-zonal system with pricing of inter-zonal congestion in the forward market seems to be a fruitful area for future research. Another direction that can be explored is the effect of repetition. Electricity auctions are repeated on a daily basis, and this may give generators a opportunity to participate in complex strategic moves that may lead to a much larger set of possible equilibria. Identifying what may be the range of reasonable outcomes may be another extension that should be explored.

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APPENDIX

Table 4. Welfare measures

State	Profit ($/hr) Gen. 1	Profit ($/hr) Gen. 2	Grid Owner Rev. ($/hr)	Consumer Surplus ($/hr)	Social Welfare ($/hr)
Unconstrained					
Single-settlement					
Opt. Dispatch (A)	800.0	200.0	0.0	1250.0	2250.0
Centralized (B)	1051.0	336.3	0.0	686.7	2074.0
Separated (C)	1051.0	336.3	0.0	686.7	2074.0
Two-settlement					
No Arbitrage					
Cen. Residual (D1a)	1052.3	320.0	0.0	738.9	2111.2
Cen. Tr. Charges (D2a)	1040.5	324.5	0.0	738.8	2103.8
Sep. Residual (D3a)	1057.1	317.1	0.0	741.4	2115.6
Sep. Tr. Charges (D4a)	1041.7	325.3	0.0	735.8	2102.8
Market Clearing					
Cen. Residual (D1b)	1189.6	468.3	0.0	519.8	2177.8
Cen. Tr. Charges (D2b)	1183.7	472.0	0.0	520.2	2175.8
Sep. Residual (D3b)	1191.7	466.9	0.0	519.9	2178.5
Sep. Tr. Charges (D4b)	1183.7	475.5	0.0	515.1	2174.3
Constrained					
Single-settlement					
Opt. Dispatch (A)	512.0	392.0	72.0	1130.0	2106.0
Centralized (B)	864.0	432.0	36.0	666.0	1998.0
Separated (C)	825.7	464.5	45.1	650.9	1986.3
Two-settlement					
No Arbitrage					
Cen. Residual (D1a)	860.0	427.0	20.4	716.5	2023.9
Cen. Tr. Charges (D2a)	841.6	426.1	38.6	715.4	2021.8
Sep. Residual (D3a)	819.5	489.4	9.6	692.9	2011.4
Sep. Tr. Charges (D4a)	806.9	416.1	48.1	739.1	2010.2
Market Clearing					
Cen. Residual (D1b)	1052.0	461.2	34.5	532.1	2079.8
Cen. Tr. Charges (D2b)	953.9	589.6	46.1	487.6	2077.2
Sep. Residual (D3b)	1035.0	473.6	19.9	539.7	2068.2
Sep. Tr. Charges (D4b)	889.8	608.4	57.3	511.2	2066.7

Table 5. Prices in the Spot and Forward Markets.

State	SPOT MARKET			FORWARD MARKET	
	Delivered Price ($/MWh)		Trans. Price ($/MWh)	Forward Price ($/MWh)	
	Node 1	Node 2	Link 1–2	Node 1	Node 2
Unconstrained					
Single-settlement					
Opt. Dispatch (A)	50.0	50.0	0.0	-	-
Centralized (B)	62.9	62.9	0.0	-	-
Separated (C)	62.9	62.9	0.0	-	-
Two-settlement					
No Arbitrage					
Cen. Residual (D1a)	61.6	61.6	0.0	61.6	61.6
Cen. Tr. Charges (D2a)	61.6	61.6	0.0	61.6	61.6
Sep. Residual (D3a)	62.0	61.0	0.0	61.8	61.4
Sep. Tr. Charges (D4a)	61.5	61.7	0.0	61.3	62.1
Market Clearing					
Cen. Residual (D1b)	56.8	56.8	0.0	71.1	71.1
Cen. Tr. Charges (D2b)	56.9	56.9	0.0	71.0	71.0
Sep. Residual (D3b)	56.8	56.8	0.0	71.1	71.0
Sep. Tr. Charges (D4b)	56.8	57.1	0.0	70.9	71.6
Constrained					
Single-settlement					
Opt. Dispatch (A)	42.0	66.0	24.0	-	-
Centralized (B)	58.0	70.0	12.0	-	-
Separated (C)	59.3	69.3	15.0	-	-
Two-settlement					
No Arbitrage					
Cen. Residual (D1a)	55.8	69.9	14.1	61.6	61.6
Cen. Tr. Charges (D2a)	56.3	69.2	12.9	61.6	61.6
Sep. Residual (D3a)	57.3	69.0	19.2	61.8	61.4
Sep. Tr. Charges (D4a)	57.6	68.5	16.0	61.3	62.1
Market Clearing					
Cen. Residual (D1b)	50.4	66.1	15.7	71.1	71.1
Cen. Tr. Charges (D2b)	50.8	66.1	15.4	71.0	71.0
Sep. Residual (D3b)	52.0	65.2	19.9	71.1	71.0
Sep. Tr. Charges (D4b)	52.2	65.1	19.1	70.9	71.6

Table 6. Generation, Sales and Transmission.

State	Quantity Demanded		Sales by Firm 1		Sales by Firm 2		Generation		Flow
	Node 1	Node 2	Node 1	Node 2	Node 1	Node 2	Firm 1	Firm 2	1–2
Unconstrained									
Single-settlement									
Opt. Dispatch (A)	25.0	25.0	40.0	0.0	0.0	10.0	40.0	10.0	15.0
Centralized (B)	18.5	18.5	26.5	0.0	0.0	10.6	26.5	10.6	7.9
Separated (C)	18.5	18.5	13.2	13.2	5.3	5.3	26.5	10.6	7.9
Two-settlement									
No Arbitrage									
Cen. Residual (D1a)	19.2	19.2	28.0	0.0	0.0	10.4	28.0	10.4	8.8
Cen. Tr. Charges (D2a)	19.2	19.2	27.5	0.0	0.0	10.9	27.5	10.9	8.3
Sep. Residual (D3a)	19.0	19.5	14.4	13.9	4.6	5.6	28.3	10.2	9.3
Sep. Tr. Charges (D4a)	19.2	19.1	14.2	13.3	5.0	5.8	27.5	10.9	8.3
Market Clearing									
Cen. Residual (D1b)	21.6	21.6	31.1	0.0	0.0	12.1	31.1	12.1	9.5
Cen. Tr. Charges (D2b)	21.6	21.6	30.9	0.0	0.0	12.2	30.9	12.2	9.4
Sep. Residual (D3b)	21.6	21.6	15.6	15.5	6.0	6.1	31.1	12.1	9.5
Sep. Tr. Charges (D4b)	21.6	21.5	15.6	15.3	6.0	6.2	30.9	12.2	9.3
Constrained									
Single-settlement									
Opt. Dispatch (A)	29.0	17.0	32.0	0.0	0.0	14.0	32.0	14.0	3.0
Centralized (B)	21.0	15.0	24.0	0.0	0.0	12.0	24.0	12.0	3.0
Separated (C)	20.4	15.4	12.9	10.4	7.4	4.9	23.4	12.4	3.0
Two-settlement									
No Arbitrage									
Cen. Residual (D1a)	22.1	15.1	25.1	0.0	0.0	12.1	25.1	12.1	3.0
Cen. Tr. Charges (D2a)	21.8	15.4	24.8	0.0	0.0	12.4	24.8	12.4	3.0
Sep. Residual (D3a)	21.4	15.5	14.0	10.3	7.3	5.2	24.4	12.5	3.0
Sep. Tr. Charges (D4a)	21.2	15.8	13.9	10.3	7.3	5.4	24.2	12.8	3.0
Market Clearing									
Cen. Residual (D1b)	24.8	17.0	27.8	0.0	0.0	14.0	27.8	14.0	3.0
Cen. Tr. Charges (D2b)	24.6	16.9	27.6	0.0	0.0	13.9	27.6	13.9	3.0
Sep. Residual (D3b)	24.0	17.4	15.2	11.8	8.8	5.6	27.0	14.4	3.0
Sep. Tr. Charges (D4b)	23.9	17.4	15.2	11.7	8.7	5.7	26.9	14.4	3.0

Table 7. Forward Sales.

State	Forward Quantity Demanded		Forward Sales by Firm 1		Forward Sales by Firm 2	
Two-settlement						
No Arbitrage						
Cen. Residual (D1a)	-	-	4.5	0.0	0.0	0.5
Cen. Tr. Charges (D2a)	-	-	3.5	0.0	0.0	3.0
Sep. Residual (D3a)	-	-	2.6	2.6	-1.0	0.6
Sep. Tr. Charges (D4a)	-	-	2.2	1.2	1.0	1.7
Market Clearing						
Cen. Residual (D1b)	14.5	14.5	15.3	0.0	0.0	13.7
Cen. Tr. Charges (D2b)	14.5	14.5	15.0	0.0	0.0	14.0
Sep. Residual (D3b)	14.4	14.5	7.7	7.7	6.7	6.8
Sep. Tr. Charges (D4b)	14.5	14.2	7.6	7.1	6.9	7.0

Table 8. Welfare Measures

State	Profit ($/hr) Gen. 1	Profit ($/hr) Gen. 2	Grid Owner Rev. ($/hr)	Consumer Surplus ($/hr)	Social Welfare ($/hr)
Unconstrained					
Single-settlement					
Opt. Dispatch (A)	3791.2	1047.1	0.0	3563.6	8401.9
Centralized (B)	4253.0	1346.7	0.0	2485.0	8084.6
Separated (C)	4330.6	1424.3	0.0	2290.9	8045.8
Two-settlement					
No Arbitrage					
Cen. Residual (D1a)	4277.4	1306.8	0.0	2567.4	8151.6
Cen. Tr. Charges (D2a)	4218.5	1314.1	0.0	2601.2	8133.8
Sep. Residual (D3a)	4348.7	1352.1	0.0	2445.1	8145.9
Sep. Tr. Charges (D4a)	4319.1	1381.3	0.0	2408.0	8108.4
Market Clearing					
Cen. Residual (D1b)	4675.5	1768.8	0.0	1857.1	8301.5
Cen. Tr. Charges (D2b)	4661.1	1787.1	0.0	1848.1	8296.3
Sep. Residual (D3b)	4776.3	1859.7	0.0	1660.7	8296.7
Sep. Tr. Charges (D4b)	4760.7	1883.1	0.0	1645.6	8289.5
Constrained					
Single-settlement					
Opt. Dispatch (A)	2800.1	1630.7	237.2	3465.5	8133.5
Centralized (B)	3601.6	1697.9	141.8	2460.4	7901.7
Separated (C)	3558.9	1872.4	172.8	2236.1	7840.2
Two-settlement					
No Arbitrage					
Cen. Residual (D1a)	3603.0	1769.2	24.7	2547.0	7943.9
Cen. Tr. Charges (D2a)	3541.8	1681.6	148.3	2571.5	7943.2
Sep. Residual (D3a)	3528.4	2052.6	-50.3	2376.7	7907.4
Sep. Tr. Charges (D4a)	3517.2	1889.0	182.2	2307.9	7896.3
Market Clearing					
Cen. Residual (D1b)	4268.4	1792.9	137.4	1890.9	8089.6
Cen. Tr. Charges (D2b)	3929.3	2197.6	165.9	1791.9	8084.7
Sep. Residual (D3b)	4312.1	1922.5	161.2	1666.7	8062.6
Sep. Tr. Charges (D4b)	3860.3	2356.7	199.8	1643.9	8060.7

Table 9. Prices in the Spot and Forward Markets

State	SPOT MARKET							FORWARD MARKET		
	Delivered Price ($/MWh)			Trans. Price ($/MWh)			Dual Price ($/hr)	Forward Price ($/MWh)		
	1	2	3	1	2	3	1–2	1	2	3
Unconstrained										
Single-settlement										
Opt. Dispatch (A)	24.5	24.5	24.5	0.0	0.0	0.0	0.0	-	-	-
Centralized (B)	26.7	26.7	26.7	0.0	0.0	0.0	0.0	-	-	-
Separated (C)	27.9	27.9	25.2	0.0	0.0	0.0	0.0	-	-	-
Two-settlement										
No Arbitrage										
Cen. Residual (D1a)	26.5	26.5	26.5	0.0	0.0	0.0	0.0	26.5	26.5	26.5
Cen. Tr. Charges (D2a)	26.5	26.5	26.5	0.0	0.0	0.0	0.0	26.0	26.0	26.0
Sep. Residual (D3a)	27.4	27.0	25.6	0.0	0.0	0.0	0.0	27.3	27.1	25.6
Sep. Tr. Charges (D4a)	27.2	27.4	25.6	0.0	0.0	0.0	0.0	37.8	38.5	33.1
Market Clearing										
Cen. Residual (D1b)	25.5	25.5	25.5	0.0	0.0	0.0	0.0	29.1	29.1	29.1
Cen. Tr. Charges (D2b)	25.5	25.5	25.5	0.0	0.0	0.0	0.0	29.2	29.2	29.2
Sep. Residual (D3b)	25.9	25.9	24.9	0.0	0.0	0.0	0.0	30.5	30.5	27.4
Sep. Tr. Charges (D4b)	25.9	26.0	24.9	0.0	0.0	0.0	0.0	30.4	30.7	27.4
Constrained										
Single-settlement										
Opt. Dispatch (A)	21.7	28.1	24.9	-3.2	3.2	0.0	9.5	-	-	-
Centralized (B)	25.0	28.7	26.9	-1.9	1.9	0.0	5.7	-	-	-
Separated (C)	26.5	29.6	25.4	-2.3	2.3	0.0	6.9	-	-	-
Two-settlement										
No Arbitrage										
Cen. Residual (D1a)	24.4	29.0	26.7	-2.3	2.3	0.0	6.8	26.5	26.5	26.5
Cen. Tr. Charges (D2a)	24.7	28.6	26.7	-2.0	2.0	0.0	5.9	26.0	26.0	26.0
Sep. Residual (D3a)	25.6	29.3	25.9	-3.0	3.0	0.0	-9.0	27.3	27.1	25.6
Sep. Tr. Charges (D4a)	25.8	29.2	25.8	-2.4	2.4	0.0	-7.3	37.8	38.5	33.1
Market Clearing										
Cen. Residual (D1b)	23.4	27.9	25.7	-2.3	2.3	0.0	6.8	29.1	29.1	29.1
Cen. Tr. Charges (D2b)	23.5	27.9	25.7	-2.2	2.2	0.0	6.6	29.2	29.2	29.2
Sep. Residual (D3b)	24.3	28.0	25.1	-2.8	2.8	0.0	8.3	30.5	30.5	27.4
Sep. Tr. Charges (D4b)	24.3	28.0	25.1	-2.7	2.7	0.0	8.0	30.4	30.7	27.4

Table 10. Generation, Sales and Transmission

State	Quantity Demanded			Sales by Firm 1			Sales by Firm 2			Generation		Flow on lines		
	1	2	3	1	2	3	1	2	3	Gen.1	Gen.2	1–2	1–3	2–3
Unconstrained														
Single-settlement														
Opt. Dispatch (A)	194.1	194.1	145.9	389.4	0.0	0.0	0.0	144.7	0.0	389.4	144.7	81.6	113.7	32.2
Centralized (B)	166.3	166.3	102.8	299.1	0.0	0.0	0.0	136.3	0.0	299.1	136.3	54.3	78.5	24.2
Separated (C)	151.7	151.7	131.9	98.8	98.8	101.5	52.9	52.9	30.4	299.1	136.3	54.3	93.1	38.8
Two-settlement														
No Arbitrage														
Cen. Residual (D1a)	168.6	168.6	106.4	312.1	0.0	0.0	0.0	131.6	0.0	312.1	131.6	60.2	83.3	23.1
Cen. Tr. Charges (D2a)	168.8	168.8	106.7	305.7	0.0	0.0	0.0	138.7	0.0	305.7	138.7	55.7	81.2	25.5
Sep. Residual (D3a)	157.9	162.1	124.1	109.3	103.1	102.6	48.7	59.0	21.5	315.0	129.2	63.3	93.7	30.4
Sep. Tr. Charges (D4a)	160.2	157.2	123.4	107.0	101.7	97.0	53.2	55.5	26.4	305.7	135.1	55.9	89.6	33.8
Market Clearing														
Cen. Residual (D1b)	181.7	181.7	126.7	335.2	0.0	0.0	0.0	155.0	0.0	335.2	155.0	60.1	93.4	33.3
Cen. Tr. Charges (D2b)	181.6	181.6	126.5	333.9	0.0	0.0	0.0	155.7	0.0	333.9	155.7	59.4	92.9	33.5
Sep. Residual (D3b)	176.0	176.1	138.2	335.6	0.0	0.0	0.0	154.7	0.0	335.6	154.7	60.3	99.2	38.9
Sep. Tr. Charges (D4b)	176.4	175.0	137.9	113.9	112.7	107.1	62.5	62.3	30.8	333.7	155.7	58.9	98.4	39.5
Constrained														
Single-settlement														
Opt. Dispatch (A)	228.3	149.3	137.7	334.7	0.0	0.0	0.0	180.6	0.0	334.7	180.6	25.0	81.3	56.3
Centralized (B)	187.9	140.7	99.7	275.3	0.0	0.0	0.0	153.0	0.0	275.3	153.0	25.0	62.3	37.3
Separated (C)	168.5	130.1	128.1	100.2	81.0	88.8	68.3	49.1	39.3	270.1	156.7	25.0	76.6	51.6
Two-settlement														
No Arbitrage														
Cen. Residual (D1a)	194.6	137.9	102.7	283.4	0.0	0.0	0.0	151.7	0.0	283.4	151.7	25.0	63.8	38.8
Cen. Tr. Charges (D2a)	191.4	141.9	103.4	280.6	0.0	0.0	0.0	156.1	0.0	280.6	156.1	25.0	64.2	39.2
Sep. Residual (D3a)	179.9	133.8	119.1	111.1	79.8	86.0	68.8	54.0	33.1	276.9	155.9	25.0	72.1	47.1
Sep. Tr. Charges (D4a)	177.8	134.4	119.4	108.5	83.0	83.6	69.4	51.4	35.8	275.0	156.6	25.0	72.2	47.2
Market Clearing														
Cen. Residual (D1b)	207.6	151.0	123.0	306.7	0.0	0.0	0.0	175.0	0.0	306.7	175.0	25.0	74.0	49.0
Cen. Tr. Charges (D2b)	206.5	151.2	122.2	305.1	0.0	0.0	0.0	174.8	0.0	305.1	174.8	25.0	73.6	48.6
Sep. Residual (D3b)	196.2	150.0	133.6	300.5	0.0	0.0	0.0	179.3	0.0	300.5	179.3	25.0	79.3	54.3
Sep. Tr. Charges (D4b)	195.8	150.0	133.6	115.5	92.1	92.4	80.3	57.9	41.1	300.1	179.3	25.0	79.3	54.3

Table 11. Forward Sales

Two-settlement	Forward Quantity Demanded			Forward Sales by Firm 1			Forward Sales by Firm 2		
	1	2	3	1	2	3	1	2	3
No Arbitrage									
Cen. Residual (D1a)	-	-	-	50.0	0.0	0.0	0.0	-17.0	0.0
Cen. Tr. Charges (D2a)	-	-	-	30.0	0.0	0.0	0.0	22.0	0.0
Sep. Residual (D3a)	-	-	-	26.6	24.6	8.7	-6.9	7.7	-30.4
Sep. Tr. Charges (D4a)	-	-	-	20.7	12.5	-6.7	7.2	6.6	-14.7
Market Clearing									
Cen. Residual (D1b)	136.0	136.0	55.8	171.0	0.0	0.0	0.0	156.7	0.0
Cen. Tr. Charges (D2b)	135.5	135.5	55.0	166.0	0.0	0.0	0.0	160.0	0.0
Sep. Residual (D3b)	118.8	119.0	89.9	62.2	61.3	48.6	56.5	57.6	41.3
Sep. Tr. Charges (D4b)	119.9	115.6	89.3	61.4	58.7	45.1	58.6	56.9	44.1