Multi-settlement Systems for Electricity Markets: Zonal Aggregation under Network Uncertainty and Market Power[1]

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Abstract

We analyze alternative market designs for a multi-settlement system for electricity in which the resolution of the transmission network model is increased as time approaches real-time, and uncertainty about congestion patterns is resolved. Variations of such systems are implemented or have been proposed in California and other parts of the U.S. We aim to compare welfare implications of such market designs against more centralized single-settlement systems, such as those implemented in the Northeastern control areas of the U.S. We model the multi-settlement system as a two-period game and compute subgame perfect Cournot-Nash equilibria for the various market designs.

1. Introduction

Over the past decade, wholesale electricity markets have gone through fundamental changes in the U.S. and around the world. 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 2000 prompted several proposal 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 reforms 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 York, and New England. In this design, an independent system operator runs real-time as well as day-ahead markets with centralized dispatch. Bilateral trades are allowed in such system and are charged a congestion fee that equals to the locational price differences between the injection and withdrawal points in the real-time market. Congestion charges can be hedged through some type of transmission congestion contracts, which are defined as financial instruments that guarantee the holder the price differential between locations specified in the contract.

The second design relies on a more decentralized approach, at least in the day-ahead energy market. The version, which 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. The version implemented in Texas relies on bilateral

[1] The work described in this paper was coordinated by the Consortium for Electric Reliability Technology Solutions on Behalf of the Department of Energy. The work was also supported by the University of California Energy Institute and by PSERC.

Proceedings of the 35th Annual Hawaii International Conference on System Sciences (HICSS-35'02)
0-7695-1435-9/02 $17.00 © 2002 IEEE

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 concerns the extent to which the costs of correcting infeasible schedules should be directly assigned to the causers 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 multi-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. As a benchmark for comparison we use a single-settlement nodal model.[2] The remainder of the paper is as follows. The next section provides a review of the relevant literature on spot market modeling, and modeling interactions between spot and contract markets. Section 3 presents our 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. Section 5 provides some concluding remarks and addresses future work.

2. Literature Review

We review literature on electricity market modeling with 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.

2.1. Electricity Market Models

Schweppe et al. [15] describe the theory of competitive electricity markets. Given costs of all generators on the network, demand, and network topology, locational prices can be calculated using 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 are just differences in equilibrium marginal costs at various locations, and can be used to set transmission charges for bilateral contracts (Hogan [11]). Studies modeling electricity spot markets in the literature, however, have focused on a non-competitive view of the spot market. Equilibria with two conjectural variations, supply function equilibria in models without transmission constraints (see Green and Newbery [9]; Bolle [3]), and Cournot-Nash equilibria in models with transmission constraints have been examined. We will focus on models with transmission constraints.

An important modeling choice is the assumption on whether agents will game transmission markets. Assuming that agents will game the market, leads to non-convex problems with possibly multiple equilibria (see Oren [13]; Cardell, Hitt and Hogan [6] among others).[3] On the other hand, if the main purpose of the model is to consider 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 [10]; Smeers and Wei [16]). In such models, first order conditions for all the generators can be aggregated along with those of transmission owners, and the equilibrium can be solved as a complementarity problem. Smeers and Wei [16] 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 [4] use a grid search algorithm to iteratively converge to a Cournot model with data on the California market. Hobbs [10] uses linearly

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

[3] See Luo, Pang and Ralph [12] for a comprehensive analysis of such problems.

decreasing demand and constant marginal cost functions, which result in linear mixed complementarity problems, to solve for such Cournot 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 [16]. 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 power market.

2.2. Contract Markets

Work in this area has focused on the welfare enhancing properties of forward markets. Theoretical studies have shown that for certain conjectural variations, forward markets increase economic efficiency through a prisoners' dilemma type of effect (see Allaz [1], and Allaz and Vila [2])[4].

The basic model in Allaz [1] 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. An arbitrage relation between forward and spot prices decides the forward 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 [5]. In the spot market, producers consider a particular producer's production as a strategic substitute.[5] The availability of the forward market makes a particular producer more aggressive in the spot market. This produces a marginal negative effect on other producers' production, and improves the profitability of the particular producer under consideration.[6] 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 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 [2] 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 if 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.

von der Fehr and Harbord [17] and Powell [14] 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 [17] focus on price competition in the spot market with capacity constraints and multiple demand scenarios. They find that contracts tend to put a downward pressure on spot prices. Although, this provides disincentive for 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 to its full capacity in more demand scenarios. They find asymmetric equilibria for variable demand scenarios where such a commitment is useful. Powell [14] explicitly models the effect of reconstructing 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 they 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.

3. Formulation

We analyze the problem with the help of several illustrative examples on a simple two-node network.

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

[5] A producer considers another producer's production quantity as a strategic substitute if an increase in the other producer's quantity has a negative effect on its own marginal profitability. This is seen by negatively sloping reaction functions in Cournot markets.

[6] Bulow, Geneakoplos and Klemperer [5] warn, however, that assumptions of linearity on the demand often produces strategic substitutes, but that this may no longer be true if the demand function exhibits constant elasticity or is nonlinear.

For the multi-settlement cases, we formulate the problem as a two period game. In period 2, we model a spot market (production game) where generators use a Cournot conjectural variation. We assume that generators take transmission prices as given and do not try to game the transmission system (Hobbs [10], and Smeers and Wei [16] make such an assumption). In all our examples, the spot market is organized at a nodal level.[7] 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 (forward game) in which this transmission constraint is ignored, and the nodes are aggregated into a single zone over which the price is uniform. Generators can enter into contracts in this period, which are settled in period 2. We analyze the following cases (a detailed description of each case follows):

Case A. *Optimal Dispatch*
Case B. *Single-settlement – Centralized Market.*
Case C. *Single-settlement – Separated Markets.*
Case D. *Multi-settlement System for Electricity* (Zonal Forward Market).
- *D1. Residual Centralized Spot Market.*
- *D2. Centralized Spot Market and Transmission Charge for Congestion Causation.*
- *D3. Residual Separated Spot Market*
- D4. *Separated Spot Market and Transmission Charge for Congestion Causation.*

In a multi-settlement system it becomes necessary to accurately describe the commodity, or the commodity price in case of financial contracts, for which forward transactions are being entered into. In the centralized market designs there is a single price in the forward market as transmission constraints are ignored in this market. In a residual market, spot transactions are settled at nodal prices. This means that there will be fewer forward prices than spot prices, and forward prices for different nodes will be equal. This will lead to arbitrage possibilities if the direction of congestion can be easily predicted. We consider two sets of cases. For one set of cases (reported as D1a and D2a 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, 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.[8] There seems to be ample empirical evidence, however, that generators cover a 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. In an attempt to explain that reality we examine a second set of cases (reported as D1b and D2b in the results). Specifically, 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.[9] This essentially relaxes the no arbitrage condition, and provides generators with the opportunity to extract a strategic premium in the forward market.

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 now describe the cases in more detail.

Case A. This is the welfare-maximizing[10] outcome and will be the solution to:

$$p_i^A = MC(q_i) \quad \textit{for all nodes with generation}, i$$
$$p_j^A = p_j(D_j) \quad \textit{for all demand nodes}, j$$
$$\sum_i q_i = \sum_j D_j$$
$$\sum_i \beta_{1-2,i}^c q_i = \bar{f}_{1-2}^c \ \textit{if transmission line constrained}$$
$$p_j = p_i + \beta_{1-2,i}\lambda^c \quad \textit{for all nodes i and hub } j\ (i \neq j)$$

[7] Another interpretation is that congestion at the intra-zonal level is also considered and priced if there is a zonal forward market.

[8] This may change, although to a small extent, with the introduction of risk-aversion in the model.
[9] This also assumes that demand behaves non-strategically.
[10] We use the sum of consumer and producer surpluses as a welfare measure.

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, λ^c is the multiplier associated with link 1–2 in state c, $c \in \{1, 2\}$ an index set of states, $\beta_{1\text{-}2,i}$ 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 $\bar{f}^c_{1-2}$ is the capacity of this link in state c.

Case B. In this case, we simulate a centralized market outcome with generators behaving à la Cournot (see Hobbs [10]). 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 non-cost differences in energy prices 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.

$$\underset{q_i}{Max}\,\Pi_i = p_i q_i - C(q_i)$$
$$p_j = p_i + \beta^c_{1-2,i}\lambda^c \quad \forall\, i \text{ and hub } j\,(i \neq j)$$
$$\sum_i q_i = \sum_j D_j$$

Though we model an equilibrium in quantities, this optimization problem is more easily modeled in prices, and the first order necessary conditions (FONCs) for this problem can be obtained after substituting the constraints into the objective function, and making p_i the decision variable. The two FONCs along with the constraints of the problem, and the flow constraint, 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 [16]). 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:

$$\underset{s_{ij}}{Max}\,\Pi_i = \sum_j (p_j(s_{ij} + \sum_{k \neq i} s_{kj}) - w^c_j) s_{ij} - C(q_i) + w^c_i q_i$$
$$(\theta_i): \sum_j s_{ij} = q_i$$

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, assuming that it cannot affect transmission prices, w^c_j in turn solves a linear program of the following form:

$$\underset{y_j}{Max}\,R^c_S = \sum_j w^c_j y^c_j$$
$$(\lambda^c): \sum_j -\beta^c_{1-2,j} y^c_j \leq \bar{f}^c_{1-2}$$

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:

$$y^c_j = \sum_i s_{ij} - q_j \quad \text{for all nodes } j$$

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:

$$\underset{q_i}{Max}\,\Pi_i = p^f f_i + p_i(q_i - f_i) - C(q_i)$$
$$p_j = p_i + \beta^c_{1-2,i}\lambda^c \quad \text{for all nodes } i \text{ and hub } j\,(i \neq j)$$
$$\sum_i q_i = \sum_j D_j$$

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 complimentary 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 multi-settlement system, we employ the notion of a sub-game perfect Nash equilibrium (SPNE) (see Fudenberg and Tirole [8]). 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.[11] 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 all transactions that are dispatched in the spot market are charged the spot transmission charge (see Chao et al. [7]). This means that any forward transactions made in the zonal market, and not reversed in the spot market, will be subject to a spot transmission charge. 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. In a centralized market, it becomes necessary to decide on a 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:

$$\underset{q_i}{Max}\,\Pi_i = p^f f_i + p_i(q_i - f_i) - C(q_i) - f_i(p_{hub} - p_i)$$

$$p_j = p_i + \beta^c_{1-2,i}\lambda^c \quad \textit{for all nodes } i \textit{ and hub } j\,(i \neq j)$$

$$\sum_i q_i = \sum_j D_j$$

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

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.

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):

$$\underset{s_{ij}}{Max}\,\Pi_i = p^f(\sum_j s^f_{ij}) + \sum_j (p_j(s_{ij} + \sum_{k\neq i} s_{kj}) - w^k_j)(s_{ij} - s^f_{ij})$$
$$- C(q_i) + w_i q$$

$$(\theta_{i_i}):\ \sum_j s_{ij} = q_i$$

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.

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:

$$\underset{s_{ij}}{Max}\,\Pi_i = p^f(\sum_j s^f_{ij}) + \sum_j (p_j(s_{ij} + \sum_{k\neq i} s_{kj}) - w^k_j)(s_{ij} - s^f_{ij})$$
$$- C(q_i) + w_i q_i - \sum_j (-w_i + w_j)s^f_{ij}$$

$$(\theta_i):\ \sum_j s_{ij} = q_i$$

The grid owner's 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.

4. A Numerical Example

Consider the example in Figure 1 with a single generator at each node of a simple two-node network. 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 would 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).

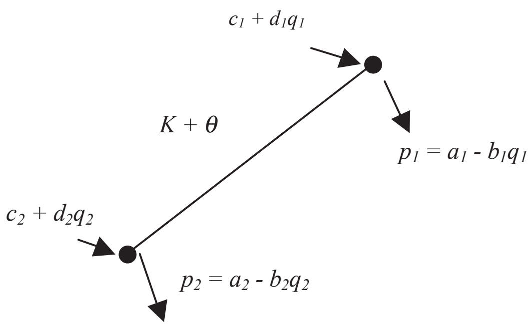

Figure 1. A Simple two-node network

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	0.05

We use the single-settlement centralized dispatch results as our benchmark (see the Appendix for results). This market design has 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 states, respectively. A general observation is that for this level of congestion, multi-settlement systems continue to be welfare enhancing, reflecting the literature on contract markets without transmission constraints. For the 'no arbitrage' cases, consumers benefit because of the higher spot production to the detriment of at least one producer, as in previous literature. The 'market clearing' cases have even higher welfare increases due to larger coverage in forward contracts; however, consumer surplus is lower as compared to the other 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 (unconstrained state).

In the 'no arbitrage' cases, spot prices average around \$62 per MWh (this is about the level they achieve in the unconstrained state; In the constrained state, spot price at node 1 is around \$56 per MWh, while at node 2 it is \$69 per MWh). On the other hand, forward prices in the market clearing case are around \$71 per MWh, with expected spot prices in this case averaging \$57 per MWh (spot prices are lower in the 'market clearing' case due to higher contract coverage). 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.

As mentioned above, a striking result is that in the 'no arbitrage' cases, having one forward period yields on average less than 15 percent contract coverage. 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. In the 'market clearing' case, firm 1 has a smaller forward position, while firm 2 has a larger forward position reducing net flow on the line.

One other significant result is that in case D3a, the generator at node 2 is “long” in the forward market at node 1. This means that it prefers to be less aggressive as compared to the single-settlement case at this node. This also has a considerable impact on the grid owner's revenue, which drops substantially 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. Concluding Remarks

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. We compare the two major approaches in market design that have emerged in the restructuring process, the centralized dispatch paradigm, and the multi-settlement system paradigm with aggregation of nodes in the forward market. We find that in the presence of market power, 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 a simple two-node network, we show that for small probabilities of congestion, multi-settlement systems are found to be welfare enhancing, mirroring results in a large body of literature that model electricity as if it is deliverable at a single location. These results seem to be driven by the incentives for generators to be more aggressive in the spot market to the detriment of its competitors. When both generators undertake such commitments a prisoner's dilemma type of effect lowers their profitability, benefits consumers and leads to higher overall welfare levels. Of course, care should be taken when interpreting results from a simple model such as ours. However, examples of severe gaming in the California market suggests that zonal aggregation should be such that congestion is rare inside each zone.

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 multi-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.

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APPENDIX

Table 2. Welfare Measures

State	Profit ($/hr)		G. O. Rev. ($/hr)	C. S. ($/hr)	S. W. ($/hr)	Spot Market Prices			Forward Market Prices	
	Gen. 1	Gen. 2				1	2	1-2	1	2
Unconstrained										
Single-settlement										
Opt. Dispatch (A)	800.0	200.0	0.0	1250.0	2250.0	50.0	50.0	0.0	-	-
Centralized (B)	1051.0	336.3	0.0	686.7	2074.0	62.9	62.9	0.0	-	-
Separated (C)	1051.0	336.3	0.0	686.7	2074.0	62.9	62.9	0.0	-	-
Multi-settlement										
No Arbitrage										
Cen. Residual (D1a)	1052.3	320.0	0.0	738.9	2111.2	61.6	61.6	0.0	61.6	61.6
Cen. Tr. Charge (D2a)	1040.5	324.5	0.0	738.8	2103.8	61.6	61.6	0.0	61.6	61.6
Sep. Residual (D3a)	1057.1	317.1	0.0	741.4	2115.6	62.0	61.0	0.0	61.8	61.4
Sep. Tr. Charges (D4a)	1041.7	325.3	0.0	735.8	2102.8	61.5	61.7	0.0	61.3	62.1
Market Clearing										
Cen. Residual (D1b)	1189.6	468.3	0.0	519.8	2177.8	56.8	56.8	0.0	71.1	71.1
Cen. Tr. Charge (D2b)	1183.7	472.0	0.0	520.2	2175.8	56.9	56.9	0.0	71.0	71.0
Sep. Residual (D3b)	1191.7	466.9	0.0	519.9	2178.5	56.8	56.8	0.0	71.1	71.0
Sep. Tr. Charge (D4b)	1183.7	475.5	0.0	515.1	2174.3	56.8	57.1	0.0	70.9	71.6
Constrained										
Single-settlement										
Opt. Dispatch (A)	512.0	392.0	72.0	1130.0	2106.0	42.0	66.0	24.0	-	-
Centralized (B)	864.0	432.0	36.0	666.0	1998.0	58.0	70.0	12.0	-	-
Separated (C)	825.7	464.5	45.1	650.9	1986.3	59.3	69.3	15.0	-	-
Multi-settlement										
No Arbitrage										
Cen. Residual (D1a)	860.0	427.0	20.4	716.5	2023.9	55.8	69.9	14.1	61.6	61.6
Cen. Tr. Charge (D2a)	841.6	426.1	38.6	715.4	2021.8	56.3	69.2	12.9	61.6	61.6
Sep. Residual (D3a)	819.5	489.4	9.6	692.9	2011.4	57.3	69.0	19.2	61.8	61.4
Sep. Tr. Charge (D4a)	806.9	416.1	48.1	739.1	2010.2	57.6	68.5	16.0	61.3	62.1
Market Clearing										
Cen. Residual (D1b)	1052.0	461.2	34.5	532.1	2079.8	50.4	66.1	15.7	71.1	71.1
Cen. Tr. Charge (D2b)	953.9	589.6	46.1	487.6	2077.2	50.8	66.1	15.4	71.0	71.0
Sep. Residual (D3b)	1035.0	473.6	19.9	539.7	2068.2	52.0	65.2	19.9	71.1	71.0
Sep. Tr. Charge (D4b)	889.8	608.4	57.3	511.2	2066.7	52.2	65.1	19.1	70.9	71.6

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Table 3. Generation, Sales and Transmission.

State	Forward Market				Spot Market								
	Sales by Firm 1		Sales by Firm 2		Quantity Demanded		Sales by Firm 1		Sales by Firm 2		Generation		Flow
	Node 1	Node 2	Node 1	Node 2	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
Multi-settlement													
No Arbitrage													
Cen. Residual (D1a)	4.5	0.0	0.0	0.5	19.2	19.2	28.0	0.0	0.0	10.4	28.0	10.4	8.8
Cen. Tr. Charge (D2a)	3.5	0.0	0.0	3.0	19.2	19.2	27.5	0.0	0.0	10.9	27.5	10.9	8.3
Sep. Residual (D3a)	2.6	2.6	-1.0	0.6	19.0	19.5	14.4	13.9	4.6	5.6	28.3	10.2	9.3
Sep. Tr. Charge (D4a)	2.2	1.2	1.0	1.7	19.2	19.1	14.2	13.3	5.0	5.8	27.5	10.9	8.3
Market Clearing													
Cen. Residual (D1b)	15.3	0.0	0.0	13.7	21.6	21.6	31.1	0.0	0.0	12.1	31.1	12.1	9.5
Cen. Tr. Charge (D2b)	15.0	0.0	0.0	14.0	21.6	21.6	30.9	0.0	0.0	12.2	30.9	12.2	9.4
Sep. Residual (D3b)	7.7	7.7	6.7	6.8	21.6	21.6	15.6	15.5	6.0	6.1	31.1	12.1	9.5
Sep. Tr. Charge (D4b)	7.6	7.1	6.9	7.0	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
Multi-settlement													
No Arbitrage													
Cen. Residual (D1a)	4.5	0.0	0.0	0.5	22.1	15.1	25.1	0.0	0.0	12.1	25.1	12.1	3.0
Cen. Tr. Charge (D2a)	3.5	0.0	0.0	3.0	21.8	15.4	24.8	0.0	0.0	12.4	24.8	12.4	3.0
Sep. Residual (D3a)	2.6	2.6	-1.0	0.6	21.4	15.5	14.0	10.3	7.3	5.2	24.4	12.5	3.0
Sep. Tr. Charge (D4a)	2.2	1.2	1.0	1.7	21.2	15.8	13.9	10.3	7.3	5.4	24.2	12.8	3.0
Market Clearing													
Cen. Residual (D1b)	15.3	0.0	0.0	13.7	24.8	17.0	27.8	0.0	0.0	14.0	27.8	14.0	3.0
Cen. Tr. Charge (D2b)	15.0	0.0	0.0	14.0	24.6	16.9	27.6	0.0	0.0	13.9	27.6	13.9	3.0
Sep. Residual (D3b)	7.7	7.7	6.7	6.8	24.0	17.4	15.2	11.8	8.8	5.6	27.0	14.4	3.0
Sep. Tr. Charge (D4b)	7.6	7.1	6.9	7.0	23.9	17.4	15.2	11.7	8.7	5.7	26.9	14.4	3.0

Proceedings of the 35th Hawaii International Conference on System Sciences - 2002

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