The Competitive Effects of Transmission Infrastructure in the Indian Electricity Market*

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Abstract

The integration of markets may improve efficiency by lowering costs or reducing local market power. India, seeking to reduce electricity shortages, set up a new power market, in which transmission constraints sharply limit trade between regions. During congested hours, measures of market competitiveness fall and firms raise bid prices. I use confidential bidding data to estimate the costs of power supply and simulate market outcomes with more transmission capacity. Counterfactual simulations show that transmission expansion increases market surplus by 17 percent, enough to justify the investment, because low-cost sellers increase supply in response to a more integrated grid.

I Introduction

The returns to public investments that reduce costs and integrate markets, such as large transportation and energy infrastructure projects, depend on market structure. Empirical studies in development and trade, for example, have started to estimate how imperfect competition may mediate the gains from falling trade costs.[1] The strategic response to infrastructure, in terms of entry, investment, pricing and other firm conduct, will in such cases determine the return on a public investment.

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[1] Faber (2014) finds that the expansion of China's highway network reduced growth in peripheral counties, which is consistent with lower transport costs, in the presence of scale economies and imperfect competition, causing production to agglomerate in nearby cities. Atkin and Donaldson (2015) use data on consumer prices across space to project that oligopolistic traders, not consumers, would capture most of the gains from a fall in the cost of world trade.

The power sector is an important empirical laboratory for how market conduct shapes the returns to infrastructure. China and India are investing furiously in transmission and distribution networks to serve growing energy demand (International Energy Agency, 2017). The World Bank estimates that developing countries need to invest $37 billion per year to increase new grid connections and achieve their electrification goals, including connecting the more than 1 billion people without power, by 2030 (Independent Evaluation Group, World Bank, 2015). The returns to these large public investments will depend on how private firms respond, since many developing countries have partway liberalized power sectors, with a mix of public and private suppliers (Besant-Jones, 2006; Joskow, 2008).

The power sector in India shows an especially stark contrast between investment in power infrastructure and the outcomes for customers downstream. Roughly 300 million Indian citizens, one-quarter of the population, are not connected to the electric grid, and for those on the grid, the government conservatively estimates supply to be ten percent short of demand (International Energy Agency, 2011; Central Electricity Authority, 2011*b*).[2] In the face of rationing, we might expect plants to be running non-stop, but the utilization of generators is rather low (Malik et al., 2011). Nor has the rapid addition of generating capacity lessened shortages over time (Bhattacharya and Patel, 2008).[3] India recently began to address these problems by adopting market-oriented reforms in the power sector to increase private investment and intra-national trade (Thakur et al., 2005).[4]

This paper studies the effect of transmission constraints on the competitiveness of a new wholesale power market in India, which was created by the recent reforms. Several aspects of this market make it ideal to study the competitive effects of infrastructure. First, I use confidential data on electricity market bids and can therefore observe the entire demand and supply curves in the market. The assumptions needed to estimate firm production costs are therefore weaker than in a trade setting, where data would cover at best equilibrium market outcomes. Second, transmission affects trade costs in a known way, with a zero marginal cost of trade up to the limit of how much the grid can carry and practically infinite cost beyond

[2]The real costs of this shortage are starting to be documented, for example in terms of foregone manufacturing output (Economist, 2012; Allcott, Collard-Wexler and O'Connell, 2016). Many customers without grid power run their own costly generators instead (Nag, 2010).

[3]Peak demand exceeded supply by 18 percent in 1996, 13 percent in 2002 and 13 percent in 2011 (Central Electricity Authority, 2011*b*).

[4]The Electricity Act of 2003 delicensed power generation, allowed open access to the power grid and established power exchanges to encourage trade. An important precursor to this Act was the Electricity Regulatory Commissions Act of 1998, which established state regulators to oversee tariff setting.

that. Third, the way that transmission contraints are applied in clearing the power market in India, to broad zones rather than individual nodes of the power grid, makes it tractable to model how these contraints affect bidding and counterfactual outcomes.

The empirical approach is in two parts. First, I present reduced-form evidence that transmission constraints provide firms the opportunity and incentive to exercise market power. I also show that firms do in fact raise bid prices in response to congestion. Second, I use a structural model of optimal bidding in the presence of congestion to recover firm costs of supply and counterfactually simulate market outcomes in a grid with greater transmission capacity. Both parts of the analysis use confidential data on hourly bids, offers and transmission constraints in the day-ahead market that are new to researchers.

Congestion gives many opportunities to exercise market power in the Indian day-ahead market. The grid is congested 46 percent of the time, meaning more power cannot physically flow between regions. When the grid is congested, suppliers may be able to raise prices in the thinner, regional markets that are broken off by transmission constraints. In the frequently constrained North region, conditional on an import constraint binding, prices are 39 percent higher than in the rest of the grid. This gap could be due to regional differences in cost or the exercise of market power.

I present reduced-form evidence that binding transmission constraints create the incentive to exercise market power, by greatly increasing market concentration and decreasing the magnitude of the elasticity of residual demand faced by sellers in constrained regions. The market concentration of the North Region, as measured by the Herfindahl index in terms of the effective number of equally-sized firms, falls from 5 to 10 firms if constraints were relaxed to 2 to 3 firms when constraints bind. The median elasticity of demand faced by a large seller falls by roughly two-thirds when transmission constraints bind.

Sellers do in fact raise bid prices in response to congestion. A main empirical obstacle is that congestion may be endogenous to bid prices or a third factor, like an unobservable demand shock, correlated with bids. I use both a regression control strategy and an instrumental variables strategy based on high-frequency variation in the allocation of transmission capacity to short-term markets to estimate the firm response to congestion. I find that firms raise bids by about ten percent of the mean bid price in congested, relative to non-congested, hours. This effect on bid prices is large given that I later estimate mean mark-ups around twenty percent across all hours.

The reduced-form evidence argues for a competitive effect of congestion but cannot measure the effect of large, counterfactual changes in transmission on market outcomes. I therefore build a structural model of supplier bidding in a constrained power grid. I calculate conditions for profit-maximizing supply offers given the competition that strategic sellers face over the grid, and then use these conditions as moments to estimate the marginal costs of electricity supply. Because transmission congestion curtails power flows and thus competition across regions, I innovate by constructing the moment conditions for each seller to reflect the competing offers, and hence the residual demand, they face *within* their own region of the grid. This local residual demand depends on the distribution of others' bids as well as the transmission constraints those bids cause to bind.

With the structural estimates of costs, I simulate counterfactual outcomes to see how market outcomes would change if more transmission capacity was built. The first counterfactual method is to calculate how optimal bid prices would change if the grid expanded and firms responded to the new residual demand curve they expect to face. This method has the advantage of using the same strategy space as the original bids, price-quantity functions, but the limitation of being only a partial equilibrium response, since firms do not account for other firms' also updating their bids in response to de-congestion. I find that, during congested hours, the optimal bid price for strategic firms decreases by roughly twenty percent of marginal cost, for an expansion of the grid into either of the constrained North or South regions. The predicted optimal response to a North region expansion, a decrease in bid prices of USD 5 per MWh, is somewhat smaller than the response to congestion estimated in the reduced form, an increase of USD 9 per MWh during congested hours, as we would expect given that the optimal response is a partial equilibrium prediction.

To solve a full equilibrium counterfactual of the market response to transmission investments, I use a constrained Cournot model. In this model firms use quantity strategies, instead of supply functions, which allows for stable equilibrium solutions in the constrained grid.[5] Market surplus in this scenario may change due to regional differences in cost and demand, but may additionally change because sellers, facing greater competition in a more integrated grid, offer more supply.

[5]The full supply function model, in price-quantity functions, yields multiple and unstable equilibria that are highly sensitive to modeling (Baldick and Hogan, 2004; Allcott, 2012).

The main finding of the paper is that the surplus gains from simulated transmission expansions are large and justify further transmission investment. In the full counterfactual model, counterfactual increases in import capacity to the North and South regions, large enough to nearly eliminate congestion, produce estimated gains of 17 percent of the total baseline market surplus. Depending on where it is built, more transmission capacity induces strategic sellers to increase their offered volume by up to 16 percent. Most of the surplus gains from new transmission accrue to sellers in exporting regions, who are able to supply more and at higher prices. Importing regions have modest or no net gains in surplus because undercutting sellers' market power, hence surplus, offsets gains to the buy side from lower prices and greater quantity.

These counterfactual investments in transmission are worth the cost. I compare the social benefits, or increased surplus, from transmission expansion to the costs of building the needed infrastructure. Because transmission investment is subject to cost-plus regulation, good data on the costs of existing transmission system elements is available from regulatory rulings. I apply this cost data to proposed grid expansion plans, in order to estimate the investment needed to relieve congestion at the margin. Under strategic Cournot conduct, expansions of transmission capacity into the North and South regions have estimated benefit-cost ratios of 1.85 and 2.74, respectively, indicating that greater transmission capacity between regions would increase social surplus.

The analysis treats the day-ahead market in isolation, though it is only one segment of the market and comprises a small share of trade. In particular, market participants may have sold power through physical contracts before bidding in the day-ahead market. I take these contract positions as exogenous in estimation and counterfactuals. I argue that, under this assumption, the surplus gains from transmission in the day-ahead market are a lower bound on the overall surplus gains in the whole power sector, and often a tight lower bound, since the day-ahead market is more exposed to congestion than other segments. Two pieces of evidence support this assumption. First, there are no financial contracts tied to day-ahead prices, so contract positions are sunk and only affect bidding behavior by shifting a firm's position on its cost curve. Therefore, my cost estimates recover the incremental cost of increasing supply beyond a firm's (unobserved) contract position. Second, I collect data on short-term contracts and show that there is no significant relationship between the volume of short-term contracts and congestion in the day-ahead market. This suggests that, at least at high frequency, short-term contract positions do not respond to congestion, so the counterfactuals capture the short-term response to transmission expansions in the whole market.

There is a burgeoning literature in development economics on the effects of market integration due to many types of public infrastructure, from railroads to mobile phone towers, of which transmission can be taken as an example (Jensen, 2007; Donaldson, 2018; Banerjee, Duflo and Qian, 2012; Donaldson and Hornbeck, 2016; Faber, 2014). Electricity distribution networks in particular have been found to increase labor supply, labor productivity and housing values (Lipscomb, Mobarak and Barham, 2013; Dinkleman, 2011). Most of this literature considers competitive markets like agriculture, whereas I focus empirically on the effects of infrastructure specific to imperfectly competitive markets like electricity generation. In such markets, the gains from economic integration may come as much through reductions in market power as through changes in production cost.

This paper contributes to the literature on the determinants of market power in electricity markets. Several influential studies compare market outcomes to observed data on costs and find significant exercise of market power in restructured markets (Wolfram, 1999; Borenstein, Bushnell and Wolak, 2002; Puller, 2007). The degree of market power has been found to depend on vertical contracting (Bushnell, Mansur and Saravia, 2008), market organization Mansur and White (2012), the form of bidding (Reguant, 2014) and arbitrage across market segments (Ito and Reguant, 2016). In theory, market power also depends critically on transmission infrastructure, which determines the extent of competition on the grid (Borenstein, Bushnell and Stoft, 2000; Joskow and Tirole, 2000). The role of transmission in mitigating market power has been less studied empiricallyDavis and Hausman (2014); Wolak (2015).[6] This paper extends the literature by using the structure of the transmission grid in the estimation of marginal costs. Knowledge of the grid structure and transmission constraints allow me to estimate costs and structural counterfactual outcomes that account for congestion.

The setting of the study is also novel, in an economically meaningful way, because the Indian power market has some features that differ sharply from the norm in markets in

[6] A related literature on congestion in operations research has focused on solution concepts for complex transmission networks (Neuhoff et al., 2005; Benjaming F. Hobbs and Pang, 2000; Xu and Baldick, 2007). A range of other empirical papers on electricity markets have noted the importance of congestion in the markets under study without analyzing it explicitly (Hortaçsu and Puller, 2008; Bushnell, Mansur and Saravia, 2008; Allcott, 2012; Reguant, 2014).

developed countries, such as a lack of financial contracting and elastic demand from electricity distribution companies (i.e., distribution companies that allow blackouts rather than pay a high price for power). I believe this paper is the first study of a power market in a developing country to use micro-level bidding data.[7] Empirical evidence on market power in this setting is therefore important, because it is not clear *a priori* whether, for example, more elastic wholesale demand due to the use of retail-level rationing might reduce the ability of wholesale suppliers to raise prices.

The rest of the paper runs as follows. Section II describes the Indian power sector and the nature of transmission congestion. Section III introduces the data and gives reduced-form evidence on congestion. Section IV introduces a model of supplier bidding and a related counterfactual model of supply and Section V describes the estimation strategy. Section VI presents estimated firm costs. Section VII presents the estimated benefits and costs of counterfactual transmission expansions and Section VIII concludes.

II The Indian electricity sector

This section places the day-ahead electricity market in the larger context of the Indian electricity sector and argues that the day-ahead market is the best market segment in which to study the costs of transmission congestion.

Electricity generation in India was dominated by the state and central governments until opening to private actors in the liberalization of the 1990s. Private investment remained low given that the most prominent buyers, distribution companies, were bankrupt monopsonists in their respective states (Bhattacharya and Patel, 2008). The Electricity Act of 2003 was a major reform intended to create a larger role for market forces in the power sector. This reform touched on nearly every aspect of electricity generation, transmission and distribution but was particularly meant to foster competition and private supply by opening access to the power grid across the country (Thakur et al., 2005).

[7]Several papers survey the experience of developing and transition countries with different stages of electricity liberalization (Bacon and Besant-Jones, 2001; Jamasb, 2005; Williams and Ghanadan, 2006). Other studies, such as Zhang, Parker and Kirkpatrick (2008), estimate cross-country regressions to evaluate electricity reform in a structure-conduct-performance paradigm.

II.A. Generation and Ownership

India's power sector is small for a country of its size. The peak generation in India of 110 GW on capacity of 187 GW in 2010, serving about 900 million grid-connected customers of a population of 1.2 billion, is comparable to the 127 GW peak on 167 GW of capacity in the Pennsylvania-New Jersey-Maryland (PJM) market, which serves 51 million people (Central Electricity Authority, 2011*b*, 2012*b*; International Energy Agency, 2011). Thermal plants generate the bulk of electricity: in 2010-11, coal plants generated 69 percent of the country's electricity, gas 12 percent, and hydroelectric 14 percent, with the balance from nuclear and imports (Central Electricity Authority, 2011*c*). Outside the formal power sector, India also has about 13% of grid capacity in captive generating units (Nag, 2010).

Electricity generation remains dominated by state actors but the role of the private sector has grown rapidly in the last decade. In 2003, the year the Electricity Act was passed, the private sector held 10 percent of total generation capacity, but that increased to 18 percent in 2010 and leapt up to 31 percent by 2013 (Central Electricity Authority, 2011*a*). This tripling of capacity share represents a six-fold increase in private-sector megawatts against a backdrop of overall capacity roughly doubling. The short-term electricity markets, described in detail below, have private sector participation above the private share in capacity overall. Large state producers sell most of their capacity through long-term physical contracts well in advance of delivery, whereas private plants wait to sell until closer to delivery. Thus, in the day-ahead market, state utilities provided 20 percent of cleared sell volumes in 2009 and a mere 7 percent in 2010 (author's calculation). Aside from private firms devoted to selling power, industrial plants in other businesses commonly buy and sell power in the wholesale market from their captive capacity.

II.B. The Day-Ahead Electricity Market

The Electricity Act of 2003 sanctioned wholesale markets for electricity and in 2008 a day-ahead market, which gets its name for hosting trade one day ahead of when the power is delivered, opened. The day-ahead market is the best channel through which to study the role of congestion in the Indian market, since it is the only market segment where market prices are calculated to account for transmission constraints.

The market is run as a double-sided auction conducted every day for each of 24 hourly blocks the following day.[8] Bidders can submit both single bids, which are functions from price to quantity for a single hour, and block bids, which specify the maximum willingness-to-pay of a buyer or minimum willingness-to-accept of a seller on average over a continuous block of hours. The unconstrained market clearance, assuming that transmission constraints do not bind, is typical of a double-sided auction.

Figure 2, Panel A shows the market clearance for an example hour (January 26th, 2010, 16:00-17:00). The clearing price is the least price at which supply and demand intersect. The clearing volume is the lesser of the supply and demand volume at the clearing price. In this hour and many others, demand is strikingly elastic in the area around USD 80/MWh (INR 4000/MWh).[9] The large, flat steps in the demand curve are bids of electricity distribution companies, which, though not willing to procure power above this price, may simultaneously be shedding load. The supply and demand curves have been shifted out by the volume of cleared block bids.[10]

The unconstrained market clearing solution may not be feasible, since power to be traded must flow through the electricity grid. The high-voltage, long-distance transmission lines that carry power between regions have physical limits on how much power they can carry. The system operator, here the National Load Dispatch Centre (NLDC), determines the capacity of the grid accounting for physical limits, externalities in the power grid and leaving some reliability margin. The transmission capacity set between regions is then allocated in an administrative manner prioritizing first long-term trade, then short-term contracts and lastly the day-ahead market (Central Electricity Regulatory Commission, 2008*a*, see Appendix A for details). The effect of the allocation process is that the day-ahead market becomes the residual claimant on transmission capacity across the whole system.

The transmission capacity availabile for the short-term markets, including the day-ahead market, is called Short-Term Open Access (STOA). Even though the physical capacity of

[8] The market is actually run on two separate power exchanges, the Indian Energy Exchange (IEX) and Power Exchange India Limited (PXI). Arbitrage between the two exchanges is easy and the correlation between day-ahead prices on the IEX, from which this paper uses data, and the PXI, the other day-ahead exchange, is 0.92 at hourly frequency and 0.98 at weekly frequency. As IEX has over 90 percent market share, among the two exchanges, I study bidding on this exchange alone throughout the paper. This focus will somewhat understate the costs of congestion.

[9] All bids in the market are originally in Indian rupees (INR). The paper uses a round exchange rate of USD 1 per INR 50, which is slightly stronger than that which prevailed on average in the study period (USD 1 per INR 46).

[10] Block bids are cleared by an iterative algorithm described in the Appendix. Blocks are a relatively small part of the Indian market and, while I incorporate blocks in the market clearance throughout, I will take them as exogenous in the counterfactual simulations.

the grid changes slowly, this quantity of declared transmission capacity changes from day to day and hour to hour because (a) different volumes of long-term contracts have been signed between regions, (b) the NLDC changes the reliability margin (buffer beyond calculated capacity), (c) there are physical externalities in the power grid and the capacity of a given line therefore depends on the expected flows on the grid and thus net demand in each region and (d) lines are taken down for maintenance or unplanned outages.

If the unconstrained market clearance implies that, for example, one region of the grid is a large net exporter, but the transmission capacity is not great enough to carry these exports, then the market is transmission constrained or "congested." To clear the market in the presence of congestion, the day-ahead market designates bids as coming from one of ten subregions, as shown in Figure 1, Panel A. I group these ten subregions into the six regions for which transmission constraints ever bind—North, East, Northeast, West, South 1 and South 2—shown in Figure 1, Panel B.[11] The physical grid is more complex than shown in Figure 1, Panel B, but this structure represents the binding links in the system well and is therefore used by the system operator to designate available transmission capacity, check for binding constraints and report these constraints to the power exchange.

Market clearance in the day-ahead market accounts for transmission congestion by splitting off areas that are constrained and clearing them separately.[12] Market splitting is done through an iterative algorithm to separate areas with binding constraints and clear them separately at region-specific prices. The idea is that prices in regions importing (exporting) at the unconstrained solution are raised (lowered) until the equilibrium imports (exports) are no more than the available transmission capacity. Appendix B describes the algorithm and gives an example of how market-splitting works, for the hour for which Figure 2 illustrated the unconstrained market clearance.

Market-splitting can produce large differences in electricity prices across regions, but the direct charges for the use of transmission capacity are small. In the Indian market, transmission charges are flat per MWh "postage stamp" charges that apply to use of the grid and transmission across regions, regardless of the available capacity at the time of use.[13] I neglect

[11]Two of these, South 1 and South 2, are technically subregions of the South but I will call them regions.

[12]Market-splitting is a zonal pricing method similar to that used in ERCOT (Texas) until 2010 and still used in the Nordpool market in Europe.

[13]During the period of study, for bilateral contracts, the selling party was responsible for a charge of USD 1.6/MWh for connecting to the national grid and an additional USD 1.6/MWh for each region through which the power traded is to flow, up to USD 4.8/MWh (Central Electricity Regulatory Commission, 2008*a*). On

these transmission charges in the analysis below as they are small, about four percent of the mean energy price, and would not change in any counterfactual scenario.

Institutional evidence suggests that participants in the day-ahead market should be treated as strategic profit-maximizers and not competitive price-takers. Many of the bidders are private, independent power producers. The Central Electricity Regulatory Commission serves as a market monitor and is concerned about the exercise of market power, to the degree that it imposed a binding price cap (of USD 160/MWh) in parts of September and early October, 2009. I will also treat public-sector firms as profit-maximizing. State firms may have other social objectives in selling power, such as keeping the power within their state, or reaching low-income consumers. However, these objectives are served by the supply of power on long-term contracts between state buyers and sellers. State actors in the short-term markets tend to be utilities from power-surplus states that are trying to profitably utilize excess capacity (Indian Energy Exchange, 2014).

II.C. Segments of the Wholesale Electricity Market

The model and analysis focuses on the day-ahead market, which is one of several ways to trade wholesale electricity during the sample period. This subsection discusses the other market segments with a view to clarifying how these segments may affect day-ahead market bidding.

There are three ways to trade wholesale electricity in India: bilateral contracts between buyers and sellers, the day-ahead market and a real-time balancing mechanism called unscheduled interchange. These segments differ in when electricity is traded relative to the date of delivery, how prices are set and regulatory limits on trade. Most trade happens through bilateral contracts set more than one year in advance of delivery, which are called long-term.[14] The remaining trade, less than one year in advance of delivery, is called short-term. Bilateral contracts set less than one year in advance of delivery, called short-term contracts, comprise a further 5 percent of generation. These contracts are brokered by power traders and most often apply to monthly or daily blocks covering all hours in a day. The last opportunity for *scheduled* power trade is the day-ahead market, which handles 2 percent of generation.

the power exchange, transactions are subject to comparable transmission charges of USD 2/MWh separately for the buyer and seller.

[14] In fiscal 2010, 90 percent of total electricity generation (809.45 terawatt-hours) was traded on long-term contracts, often between state-owned generators and state-owned distribution companies for a large share of a generator's output (Central Electricity Regulatory Commission, 2011).

Scheduled power is reported to the system operator before delivery. The balance of about 3 percent of generation is not scheduled, but demanded and supplied in real time in regulated quantities and at administered prices through a mechanism called unscheduled interchange (UI) (described in Appendix A).

Market conditions on the day-ahead market appear representative of the short-term part of the market. Each market segment is settled separately and there are limits to arbitrage across different market segments (Appendix A.1). However, prices in different short-term market segments remain highly correlated (Appendix Table A1).

A concern with studying the day-ahead market in isolation is that prices and quantities in other market segments, in particular the contract market, will affect day-ahead bidding. The approach of this paper is to treat contract positions as exogenous and fixed for the purposes of estimation and counterfactual analysis. This approach is necessary, since it is not possible to link de-identified day-ahead bidders to their contract positions. Taking contract positions as exogenous will affect the interpretation of marginal cost estimates and counterfactuals, but still yields a reliable short-term estimate of the gains from transmission expansion in the whole electricity sector. Several points argue for this approach.

First, for the purposes of estimating marginal costs from day-ahead bidding, physical contract positions are sunk. These positions therefore only affect bidding by shifting firms out along their marginal cost curves, such that the relevant cost in the day-ahead market is the incremental cost of supply beyond the (unobserved) contract position (See Section B.5 for the derivation).[15] With contract positions assumed fixed, these "day-ahead" marginal costs are the right costs to run counterfactuals in which suppliers change their day-ahead offers.

Second, data on the contract market suggests that taking contract positions as fixed is the right counterfactual assumption over the short- and perhaps medium-term. As noted above, most contracts are greater than one year, and therefore do not respond to market conditions at high frequency. Among short-term contracts, of less than one year, 81% of volume is in contracts of a month or more (Table A2). Thus the stock of contracts turns over slowly. To

[15] In other electricity markets, spot bidding would also be affected by forward financial positions. In the PJM (United States), NEM1 (Australia) and Spanish markets, 90 percent, 88 percent and 91 percent of physical output has been covered by financial contracts by the time power is traded in the spot market, meaning that the supplier offering power is not exposed to the spot market price (Allcott, 2012; Reguant, 2014). In India, due to restrictive financial regulation, there is no forward financial contracting tied to electricity spot prices (Sharma and Vashishtha, 2007). Thus suppliers in the Indian market day-ahead market earn the day-ahead price on their entire cleared quantity

test whether contract positions respond to congestion at high frequency, Section A.4 regresses contract volume in a given hour on congestion in that hour in the day-ahead market. In a regression with three years of hourly data, I find a small and statistically insignificant relationship between contract volume and realized congestion in an hour, suggesting that congestion is either not predictable or not a driver of contract positions in the short-term.

Third, if contract positions were endogenous we may expect that the updating of contract positions would make transmission expansions more pro-competitive. The ability to commit to forward positions increases the supply of oligopolist competitors (Allaz and Vila, 1993; Bushnell, Mansur and Saravia, 2008; Ito and Reguant, 2016). Increases in transmission capacity that increase residual demand elasticity, and therefore quantity supplied, may therefore have pro-competitive effects through the endogenous updating of physical contracts.

III Reduced-form Evidence on Congestion and Competition

This section introduces the data and presents reduced-form evidence that congestion has large effects on the competitiveness of the power market. The analysis covers the prevalence of congestion, the effect of congestion on market concentration and the incentive to exercise market power, and finally how congestion changes bid prices.

III.A. Data

The analysis uses confidential data on bids and transmission constraints from the Indian Energy Exchange (IEX) and the system operator (NLDC), respectively.

From the exchange, I use the bids and offers from participants in the day-ahead market. Bids are step functions from price to quantity with up to 32 allowed steps from the price floor of USD 0/MWh to the ceiling of USD 400/MWh.[16] From the system operator, I use transmission constraints as supplied to the exchange on the afternoon of the day of bidding. These constraints include, for every hourly block, both margin constraints on the maximum exports and imports permissible for each regional node and path constraints on the maximum

[16] The Indian Energy Exchange allows piecewise-linear bids that are strict functions from price to quantity between up to 64 points. In practice, bidders almost always use these functions to closely approximate step functions (strictly correspondences) with constant quantities for a range of prices and then discrete increases in quantity over a single price tick. The difference between step functions and the linear interpolation of the exchange makes a trivial difference in clearing prices. I therefore assume bids have a step-function structure and apply the share-auction framework for modeling bids in terms of incremental quantities at each step (Wilson, 1979) (see Appendix A for details).

flows over each inter-regional path in each direction.[17] I limit the sample of hourly auctions to the inclusive six-month period from November, 2009 through April, 2010 to study the bidding response to congestion within a constant regulatory framework.[18]

Table 1 presents summary statistics on bidding over the sample period that describe an active and unconcentrated market. The average unconstrained clearing price across auctions (Panel A) is USD 87.06/MWh, with a standard deviation of USD 48.52/MWh (Cf. the average price in the PJM market of USD 66.72/MWh for 2010 (Monitoring Analytics, 2011)). Auctions have wide participation, with an average of 19 buy bids and 25 sell bids in each auction (column 1), and as many as 48 and 54 bids in some auctions (column 5). Most bidders use few steps (Panel B), with sellers offering a bid on average with only 1.84 steps and the modal offer having a single step.[19] Steps offer an average quantity of 34 MW at an average price of USD 67/MWh, but sellers offer steps of up to 1000 MW at prices of up to USD 300/MWh.

III.B. Prevalence of Congestion

During the sample period congestion is frequent and has a large impact on market prices. Table 2 summarizes the prevalence of congestion during the sample period by comparing the prices for each pair of regions, which differ only if the regions are separated by constrained links. Panel A shows the percentage of the hours over the sample period during which the price in the row region is higher than the price in the column region. The most common patterns of congestion are for the North region or some combination of the South 1 and South 2 regions to be import constrained with respect to a central core made up of the East and West regions. The North region is constrained away from the Northeast, East and West regions over 18 percent of the time during this period. The South 1 region is import constrained with respect to this core 23 percent of the time and the South 2 region 26 percent of the time, as the link between the South 1 and South 2 regions also occasionally binds. Because constraints into the North and South tend to bind at different times, overall some constraint binds in 46

[17]During the study period, the system operator declared what the constraints were over the course of the day only if congestion occurred in any hour of the day in the unconstrained solution. On seven of 181 days in the sample, no congestion occurred, so the bootstrap simulations and counterfactual will assume that the market was unconstrained on these seven days.

[18]The price cap was lifted in October, 2009. Such a binding cap would invalidate the first-order approach to bidding optimality used in the estimation below. In May, 2010, the schedule of administrative prices for Unscheduled Interchange was revised. As the UI price schedule may influence the opportunity cost of buying and selling power in the day-ahead market, I truncate the sample before this regulatory change.

[19]This limited use of a complex strategy space occurs in other markets (Hortaçsu and Puller, 2008).

percent of the hours in the data (not shown in the table).

These binding constraints create large differences in market prices across regions. Table 2, Panel B shows the row region price less the column region price, conditional on the row region price exceeding the column region price. The average price difference between the North and East regions is USD 33.8/MWh, and between the South 1 and East regions USD 33.1/MWh, each about 38 percent of the mean unconstrained market-clearing price of USD 87.1/MWh. Appendix A.3 additionally shows that the amount of power flowing between regions is negatively correlated with differences in regional prices. Overall, it is clear that transmission congestion has very large effects on market prices in different regions of the grid.

III.C. Effect of Congestion on Market Concentration

The fact that transmission constraints open up large differences in regional prices is consistent with either a competitive or an oligopolistic market. In a competitive market, transmission constraints increase price differences by preventing least-cost dispatch across the whole grid, so that areas with high costs see high prices. In an oligopolistic market, additionally, suppliers will change their bids in response to transmission constraints, which may exacerbate regional price differences relative to differences in cost.

This subsection presents reduced-form evidence, from market concentration and residual demand elasticities, that suppliers indeed face incentives to change their bidding behavior when transmission constraints bind. Figure 3 shows how the distribution of the Herfindahl-Hirschman Index (HHI) of market concentration changes when transmission constraints bind. The HHI is based on sellers' offered volumes. The sample is restricted to hours in which the North Region is constrained from the rest of the grid (Panels A and C), or in which the South Region is constrained from the rest of the grid (Panels B and D). The HHI is then computed, using the same offered volumes, either only in the constrained region (North in Panel A, South in Panel B), or within the grid as a whole. Because this exercise uses micro-data on bids and constraints, the comparison is not between hours when the grid was constrained and hours when it was not, but between concentration when the grid was constrained and what concentration would have been, in the same hours with the same bids, had the grid not been constrained (i.e., if more transmission capacity was built).

The figure shows large increases in concentration when constraints bind. In the North

Region, the modal HHI without constraints, in Panel A, is between 0.1 and 0.2, and with constraints, in Panel C, is between 0.4 and 0.5. Thus binding constraints cut the number of effective (equally-sized) firms from 5 to 10 to 2 to 3.[20] There are a number of hours with very high concentrations, above 0.5, which are never observed when transmission constraints do not bind. The difference in concentration caused by transmission constraints in the South Region, comparing Panels B and D, is even greater, because the supply side in the South is very thin with relatively few participants.

The effect of market concentration, alone, on the incentive to exercise market power is ambiguous in this setting. In more concentrated markets, there are fewer bidders and therefore, at a given price, the slope of the residual demand curve of a supplier must be flatter. This slope effect tends to decrease the elasticity of residual demand and increase the incentive to raise prices. However, when the market is constrained, the residual demand curve shifts inwards by the quantity of imports or outward by the quantity of exports. The local market will clear at a different price point on the residual demand curve, at which quantity-price pair the residual demand may have a higher or lower elasticity. Because congestion induces both rotations and shifts of the residual demand curve, a seller in a constrained region does not necessarily face a lower elasticity of residual demand for the same bid.

Table 3 explores these effects for sellers in the North (Panel A) and South (Panel B) Regions facing import constraints. The table compares the elasticity of residual demand faced by the largest seller in each region, if they offered the same quantity (ninety percent of their capacity), with transmission constraints either not binding (column 1) or binding (column 2). As with Figure 3, the sample for each panel is limited to hours in which the constraint actually did bind, so that the column 1 statistics are counterfactuals, without constraints, holding bids fixed. Each panel reports the median of three statistics: the HHI discussed above, the slope of the residual demand curve at the offered quantity, and the elasticity of the residual demand curve at the offered quantity. As noted above, the HHI increases by a factor of two or more when constraints bind, compared to the same hours unconstrained. The slope of residual demand also falls in magnitude, for example from -22 MWh/USD to -15 MWh/USD in the North. This change in slope, and the shifts in residual demand from imports, combine to cut the residual demand elasticity from -8.60 to -3.15, roughly a third the

[20] An HHI of 1 indicates monopoly, 0.5 two equally sized firms, 0.20 five equal firms, etc.

magnitude. Using a simple Lerner pricing rule, the mark-up over cost implied by an elasticity of -9 is 12.5%, whereas that implied by an elasticity of -3 is 50%, suggesting that constraints have a large effect on the incentive to exercise market power in the North Region.[21] The South Region also sees falls in the magnitude of the slope and elasticity of residual demand when constraints bind. However, sellers in the South are small to begin with, with modest inframarginal quantities, and residual demand remains relatively elastic for the largest South seller even when the South Region is import constrained ($\varepsilon_{Q,P} = -12$).

III.D. Effect of Congestion on Bid Prices

Comparing market structures and residual demand, it is clear that sellers have much stronger incentives to exercise market power when transmission constraints bind. This section presents evidence on how transmission congestion affects prices actually bid.

The main empirical concern is the endogeneity of congestion to bid prices or unobservables correlated with bid prices. Bids may have a direct effect on congestion; if a seller in an importing region bids a high price, then the net demand of that region at lower prices will increase, tending to induce congestion. Bid prices may also respond to demand shocks that increase the likelihood of congestion. In this case congestion would be correlated with higher bids even if bidders did not directly respond to congestion.

The empirical approach is twofold. First, a regression control approach that uses high frequency variation in congestion and controls for the determinants of demand (temperature, hour) to reduce concern about unobservable demand shocks. Second, an instrumental variables approach using variation in the availability of transmission capacity, short-term open access (STOA), to instrument for congestion. The identification assumption (exclusion restriction) is that STOA, conditional on date, time and other controls, will affect bid prices only through congestion. The instrument, as described in Section II.B., varies both with long-term contracting decisions and with short-term shocks to transmission capacity. The exclusion restriction would thus be violated if long-term contracts anticipated congestion at high frequency. The facts that contracts are signed well in advance of delivery and for long durations (Section A.4) provide support for the identification assumption.

Table 4 presents specifications regressing prices bid by sellers in the North region on

[21] $L = (P - C)/C = -\frac{1}{\varepsilon} = -\frac{1}{3} \Rightarrow P = (3/2)C.$

congestion. We use the North region sample because it is the only one of two frequently congested regions with indigenous strategic sellers. The regression is at the bid-tick by hour level (a bid may have multiple steps) and the dependent variable is the price of a bid tick in USD per MWh. Observations are weighted by bid quantity so that the coefficients represent the effect per MWh bid. Congestion is a dummy for whether the North region price is different than (nearly always, higher than) the West region price. Columns 1 through 3 give OLS specifications and column 4 the 2SLS specification, for which the corresponding first stage is given in column 5.

The coefficient in column 1 shows that prices bid are 7.86 USD per MWh higher in congested hours, relative to a mean of 95.56 USD per MWh in the sample as a whole (including both congested and uncongested hours), conditional on month fixed effects, a quartic polynomial in hour of day and dummy variables for each decile of temperature, an important determinant of demand. Column 2 moves from month to date fixed effects and column 3 further adds bidder fixed effects and separate quadratic controls for quantity offered by each bidder. The coefficients with both sets of finer controls are similar to that in column 1. In the column 3 specification, with bidder fixed effects, the same bidders bid prices 6.38 USD per MWh (standard error 0.63) higher in congested hours than they bid in uncongested hours for the same quantity.

As discussed above, it may be that congestion is in part due to the higher prices offered. Column 5 shows the first stage of the instrumental variables specification, retaining the controls of the OLS specification in column 3. As congestion is binary this is a linear probability model. For each 100 MW of additional transmission capacity (STOA) into the North region, the probability of congestion decreases by 3.4 percent (standard error 0.46 percent). In column 4 we instrument for congestion using STOA and find a coefficient of price bid on congestion of 8.94 USD per MWh (standard error 2.19). While the point estimate is larger, I cannot reject that this estimate is the same as the OLS estimate in column 3. Both of these estimates suggest congestion has a meaningful effect on bid prices. The IV estimate is nearly ten percent of the mean price bid. Section VI below will estimate mark-ups of roughly twenty percent on average. This estimate implies that the estimated change in bid prices due to congestion is equal to perhaps 12 percent of cost or 60 percent of mean mark-ups.

The reduced-form evidence shows that transmission congestion is common, has large effects on market concentration and the incentive to exercise market power, and that in fact bidders do bid higher prices in response to congestion. The next section will lay out a model of supplier bidding to answer two further questions beyond the scope of a reduced-form empirical approach, in particular, what would be the overall change in market surplus due to a counterfactual expansion in transmission capacity.

IV Model of Supplier Bidding with Transmission Constraints

To measure how transmission constraints affect market outcomes, I estimate firm costs and compute counterfactual market outcomes with different levels of transmission capacity. Under strategic conduct, firm costs are estimated from supply bid functions using a first-order approach accounting for the effect of transmission constraints on residual demand.[22] The innovation in the methodology for cost estimation here is to account for the effect of transmission constraints on optimal bids.

IV.A. Model of Optimal Bidding

The model assumes that strategic firms submit supply functions to maximize expected profits. Firms face uncertainty over the bids of other firms and demand and submit their bids to the market one day ahead for each hour of the following day.

The offered supply of firm i in region g and time period t in the day-ahead market is represented by a supply function $q_{it}(p)$.[23] The firm submits a supply function to maximize profits given the expected distribution of other firms' bids and demand, accounting for transmission constraints. The firm's problem is:

$$max_{\mathbf{b_{it}},\mathbf{q_{it}}} \mathbb{E}_{\sigma_{-it}} \left[q_{it}(p)p - C_i(q_{it}(p)) \right],$$

where the supply function $q_{it}(p)$ depends on the price b_{itk} and incremental quantity q_{itk} of each bid tick k and $C_i(\cdot)$ is i's cost of incremental production in the day-ahead market.

[22] This estimation approach, pioneered by Guerre, Perrigne and Vuong (2000), was adapted for electricity markets by Wolak (2003) and has been used by Reguant (2014) to study complex bidding in the Spanish market and Allcott (2012) to study real-time pricing in the PJM market.

[23] This supply function is a continuous approximation to the step supply correspondence $\hat{q}_{it}(p) = \sum_k q_{itk}\mathbf{1}\{b_{itk} < p\} + \alpha q_{itj}\mathbf{1}\{b_{itj} = p\}$ for $\alpha \in [0, 1]$. The firm supplies the incremental quantity q_{itk} at all prices strictly above b_{itk} and may offer any part α of an incremental quantity when the market price exactly equals the price of the bid tick, with the exact quantity supplied determined by market clearing.

The market clearing condition is that quantity supplied equal residual demand at the market-clearing price, $q_{it}(p) = D^{rg}_{it}(p|\sigma_{-it}, \mathcal{L}_t)$, where $D^{rg}_{it}(p|\sigma_{-it}, \mathcal{L}_t)$ is the residual demand facing firm i in region g, σ_{-it} are the strategies of bidders other than i, including demand bids and the competitive fringe, and $\mathcal{L}_t$ the set of transmission constraints.

Taking the derivative with respect to each bid-tick price, a necessary first-order condition for profit maximization is

$$\mathbb{E}_{\sigma_{-it}}\left[\frac{\partial p}{\partial b_{itk}}\left(q_{it}(p) + \frac{\partial D^{rg}_{it}(p|\sigma_{-it}, \mathcal{L}_t)}{\partial p}(p - C'_i(q_{it}(p)))\right)\right]\Bigg|_{p=b_{itk}} = 0, \tag{1}$$

after substituting using both the market-clearing condition and the implicit function theorem. This is a Lerner pricing rule whereby the firm sets prices at marginal cost plus a markup given by quantity over a weighted expectation of the slope of residual demand. The weights $\partial p/\partial b_{itk}$ are the slope of the market price in the bid tick price and have an economic interpretation as the probability that a given bid tick sets the market price, since with no smoothing this derivative is equal to one if a bid tick is marginal and zero otherwise. A greater slope of residual demand $\partial D^{rg}_{it}/\partial p$ reduces the optimal markup at each quantity supplied.

The profit expression and first-order condition as written do not depend on the forward contract position of the firm, either a forward financial position or physical position. There are no forward financial positions in the Indian context since there are no financial contracts tied to day-ahead market prices. Firms may have forward physical positions, which are settled in contract markets prior to the day-ahead market. I take these positions as exogenous. In this case the only affect of forward positions on day-ahead bidding is that the marginal cost $C'_i(q_{it}(p))$ gives the incremental cost for supplying a unit of power beyond the (unobserved) forward contract position; firms that have sold power forward will be on a different part of their cost curve (See Appendix B for the first-order condition with a forward position).

The residual demand faced by each firm will depend on both the bids of other firms and the amount of transmission capacity. The residual demand facing firm i in region g is

$$D^{rg}_i(p|\sigma_{-it}, \mathcal{L}_t) = \sum_{j \neq i, j \in \mathcal{A}_g(p|\mathcal{L}_t)} q_j(p, \sigma_j) - \mathcal{F}(\mathcal{A}_g|p, \mathcal{L}_t).$$

The residual demand that a bidder faces in their own region consists of demand and competing supply bids $q_j(p, \sigma_j)$ within the same constrained area, which are sensitive to price, and the fixed quantity that the region is importing, which is not sensitive to price at the margin, conditional on the set of binding constraints. I designate by $\mathcal{A}_g(p|\mathcal{L}_t)$ the set of regions to which region g is connected by unconstrained transmission lines at a price p and given line capacities $\mathcal{L}_t$, and call such a group of regions an area. These connections may be direct or indirect, through another region; all regions connected by any unconstrained path form an unconstrained area. As the price in g rises, the region will tend to import more (attract net supply from other regions), which will induce transmission constraints to bind and tend to isolate g in an area. (The area will also depend on the bids and prices in other regions, and thereby the net demands of those regions; I suppress this dependence in the area notation). This constrained area $\mathcal{A}_g(p|\mathcal{L}_t)$ is determined using the market-splitting algorithm described in Section II. Let $\mathcal{F}(\mathcal{A}_g|p, \mathcal{L}_t)$ be the net constrained flows into area $\mathcal{A}_g$ at price p and line capacities $\mathcal{L}_t$. This function gives the net supply of other regions, truncated by the available transmission capacity.

The derivative of the residual demand for this firm with respect to price is

$$\frac{\partial D_{it}^{rg}(p)}{\partial p} = \sum_{j \neq i, j \in \mathcal{A}_g(p|\mathcal{L}_t)} \frac{\partial q_{jt}(p, \sigma_j)}{\partial p},$$

assuming that the constraints are not exactly binding, so that a small change in price does not change $\mathcal{A}_g(p|\mathcal{L}_t)$. Using this area assumes that bidders solve forward the congested area to which they will belong for possible realizations of other bids, but do not change their bids to manipulate this area. (The assumption that constraints do not exactly bind for a given realization of demand and supply bids is innocuous, because the empirics will simulate uncertainty over others' bids, so that all strategic bids are a best response to some probability of constraints binding.) If the set of binding constraints does not change, then constrained flows $\mathcal{F}(\cdot)$ are also fixed, so the second term in residual demand has a derivative of zero. The smaller is the constrained region $\mathcal{A}_g(p|\mathcal{L}_t)$, the weakly less negative is the residual demand slope bidder i faces, as all bids outside of $\mathcal{A}_g$ contribute a fixed amount of imports or exports. The slope of residual demand for each bidder, for a given realization of demand and other supply bids, comes from only those bids with an open link to that bidder's region.

The overall effect of transmission constraints on supply bids will depend on the exact shape of the residual demand curve. Although the residual demand slope at a given price unambiguously falls when a region is constrained, the distribution of equilibrium prices in a region will change as constraints bind more often. A bidder may therefore expect bid ticks higher (lower) in the price distribution to be marginal if its region is import (export) constrained and will set markups based on the slope of residual demand in that range of prices, instead of in the range of prices anticipated without congestion. For example, a supplier in an import-constrained region may face more elastic demand at the high area-clearing prices expected to be marginal when constrained, inducing an expansion of quantity supplied. Conversely, a supplier in an import-constrained region gaining market share and serving greater inframarginal quantity would tend to increase markups.

IV.B. Cournot Counterfactual

In the counterfactual simulations I consider both competitive conduct, wherein bids are taken as cost and held fixed, and a Cournot model, wherein strategic bidders offer fixed quantities.

The Cournot model is a simplification of the strategy space since the day-ahead market allows for bidding of not only quantities but price-quantity functions. Equilibria in supply functions, however, even without transmission constraints, are typically numerous and unstable (Allcott, 2012; Holmberg, 2009; Baldick and Hogan, 2004, 2002), and there are additional computational difficulties in a constrained network (Wilson, 2008). Klemperer and Meyer (1989) show that the supply-function equilibria lie between competitive equilibrium and Cournot, wherein strategic sellers offer fixed quantities (i.e. inelastic supply functions).

Cournot models are therefore very widely used in empirical analysis of restructured electricity markets (Ito and Reguant, 2016; Bushnell, Mansur and Saravia, 2008; Puller, 2007; Neuhoff et al., 2005; Willems, 2002; Cardell, Hitt and Hogan, 1997). The Cournot model may be an especially good fit to the Indian market for two reasons. First, since firms use a small part of the strategy space in practice, with most bids having a single step, limiting firm strategies is preferable to limiting the number of firms, as a way of simplifying the model solution. Second, a relatively elastic demand side at the wholesale level leads to reliable price discovery in the model (as opposed to the common case of both electricity demand and supply being nearly inelastic, where the market price can vary wildly).

In the simulations I take all sellers in the North and West regions with greater than a one-percent share of total offered sell volume to be strategic and treat the other bidders as a competitive fringe. The market is not very concentrated overall; this set of 13 strategic firms covers 71 percent of all offered sell volume in the sample. I consider only strategic suppliers in the North and West regions because these regions are important in themselves, as large load and supply centers, respectively, and form relatively liquid markets when constrained, enabling a smooth approximation to the residual demand curve in each region. Not allowing other sellers, outside these thirteen, to adjust their bid functions will tend to understate the effect of transmission congestion on conduct and market outcomes.

A Cournot equlibrium is a set of quantities for strategic firms i such that they cannot profitably change quantity given their marginal costs γ_i, capacity constraints $\overline{q}_i$ and residual demand, where residual demand is composed of demand bids less the supply bids of fringe firms. Appendix B gives necessary and sufficient conditions for an equilibrium set of quantities and describes the solution algorithm.

An example of the solution to the model, unconstrained, is shown in Figure 2, Panel B, which shows the Cournot model simulation for the same hour for which Panel A, previously discussed, shows actual market clearance. In Panel B the increasing solid curve represents the marginal cost curve for strategic suppliers (author's estimates). The decreasing solid curve is the residual demand curve, composed of demand bids and fringe supply bids, and the dashed-and-dotted line is a smoothed representation of the inverse residual demand. The vertical line is the equilibrium strategic quantity offered by the strategic suppliers, at which the equilibrium conditions are satisfied with respect to the smoothed inverse residual demand, as further expansion of quantity would steeply push down the market price. The market-clearing price for the simulation is the intersection of the strategic quantity with the actual, not smoothed, residual demand curve, and in this case matches exactly the actual clearing price in Panel A.

The above equilibrium applies to the realized residual demand curve faced by each seller within their own constrained area. The solution algorithm mimics the market splitting algorithm in order to determine what constrained area each seller is bidding within, first solving for the unconstrained solution with endogenous bids and then breaking off constrained areas and solving within each constrained area separately, shifting residual demand by the constrained level of imports or exports. The equilibrium in this model is not necessarily unique in theory, due to transmission constraints and the fact that I have not restricted the functional form of inverse residual demand to be concave. I explore this concern with counterfactual simulations in Appendix B and do not find multiple equilibria in practice.[24]

V Estimation

I apply the generalized method of moments (GMM) to the first-order conditions for optimal bids to estimate the marginal cost of electricity supply for firms over the quantity they offer in the day-ahead market.

To approximate the uncertainty faced by suppliers I resample demand bids and the supply functions offered by other firms. Bids from all other bidders are drawn in complete days at the region-by-bidder-type level, where regions are the six regions in Figure 1, Panel B and the bidder types are State Generating Companies, Private Generating Companies, Distribution Companies and Industrial Firms.[25] This resampling method is a block bootstrap which allows for arbitrary correlation among bids within region-bidder-day blocks. When there is a single bidder of a given type in a given region, this procedure maintains that bidder's identity, while when there are many bidders, such as industrial consumers on the demand side, it replicates the uncertainty caused by such firms dropping in and out of the market.

The estimation moments are the empirical analogue of the first-order condition (1):

$$m_{ikh}(\gamma_i) = \frac{1}{|H(h)|S} \sum_{t \in H(h)} \sum_{s=1}^{S} \frac{\partial \tilde{p}^s}{\partial b_{itk}} \left(\tilde{q}_{it}(b_{itk}) + \frac{\partial \tilde{D}_{it}^{rgs}(p^s | \sigma_{-i}^s, \mathcal{L}_t)}{\partial p} (b_{itk} - C_i'(q_i(b_{itk}))) \right), \quad (2)$$

where $s \in \{1, \ldots, S\}$ are bootstrap iterations, $H(h)$ is the set of times with hour equal to h, and a tilde indicates a smoothed function. I take $S = 100$. Every bootstrap draw of bids σ_{-i}^s generates a residual demand curve that may differ both in its component parts and in the regions over which it is aggregated, depending on what transmission constraints the bids drawn induce to bind. The moments reflect uncertainty over the composition of one's own constrained area as well as others' bids. As bids are represented discretely, the derivative of residual demand, a key determinant of mark-ups, equals zero at almost all prices. I therefore smooth the residual demand function over prices with a normal kernel to approximate this derivative and the probability that a bid tick sets the market price (see Appendix B).

[24]The main reason is that the pattern of congestion for regions in the Indian grid is very one-sided: regions that are typically import constrained may not have the supply capacity, let alone the incentive, to congest the line going outwards, which might allow a different equilibrium.

[25]Other bidder-days are drawn with weights in proportion to a triweight kernel in number of days from the day for which uncertainty is being simulated, with a bandwidth of 14 days.

The parameters of interest are the marginal cost functions for each bidder. I specify $C_i(q) = \gamma_{i0} + \gamma_i q$ so that marginal costs are constant at γ_i. Empirical papers on electricity markets have used a range of specifications for marginal cost suited to the question at hand.[26] The assumption is that marginal cost is constant over the quantity offered in the day-ahead market. In support of this idea, the average sell bid described in Table 1 has less than two bid steps and only three strategic sellers average over three steps per offer. This means sellers do not bid as if their marginal costs have much slope and, practically, means there is little variation available in bids to estimate any changes in marginal cost with quantity.

I also estimate a capacity constraint for each seller in each month as the maximum quantity offered by that seller in that month. I choose one month because most contracts, which would determine the residual capacity sellers can offer in the short-term market, are of monthly duration or longer (Section A.4). I will report as a robustness check estimates with capacity constraints as the maximum offer over the whole sample. Sellers sometimes offering at their capacities in quantity does not invalidate the first-order conditions used in estimation, as the first-order conditions are with respect to price. All bid ticks are below the ceiling price, so bidders can always raise the price of their last unit of quantity, even if they cannot offer more quantity. The smoothing of residual demand using a normal kernel also ensures that all firms will have some non-zero demand elasticity, and therefore informative first-order conditions.

I estimate the marginal cost parameter γ_i for each strategic seller by summing moments $\overline{m}_{iko}(\gamma_i) = \sum_{h \in o} m_{iko}(\gamma_i)$ over four equal hourly blocks o and solving for the GMM estimator that minimizes the inner product of these moments

$$\hat{\gamma}_i = \arg\min_{\gamma} \overline{m}_{iko}(\gamma_i)' \overline{m}_{iko}(\gamma_i).$$

One concern with this estimation strategy is that the residual demand a bidder faces may be endogenous with respect to econometric errors in their bid. For example, suppose a bidder has a positive cost shock for a given hour and this forces an offer at a high price, making a bidder marginal in a less elastic region of the demand curve. The estimation moment will infer from the low elasticity of demand that the bidder has a high mark-up and thus low cost, whereas the bidder actually was high cost because causality ran from bid to elasticity, and not

[26] Papers on vertical integration and transmission have used constant or piecewise constant marginal costs (Neuhoff et al., 2005), whereas Reguant (2014) estimates linear marginal costs and adjustment costs to capture dynamic firm decision-making important for the study of complex bids.

vice versa. I therefore use temperature at the region-by-hour level from the day of bidding to instrument for the estimation moments in the main estimates.

Standard errors are bootstrapped to account for both statistical and simulation error. I bootstrap 100 samples, where each sample draws with replacement both days from the observed sample and simulated market outcomes, for each sampled day, from a set of 100 simulations of daily market outcomes.

VI Results

VI.A. Estimated Marginal Costs

The characteristics and estimated marginal costs of strategic sellers are shown Table 5. There are four strategic sellers in the North and nine in the West. They are a heterogeneous lot, representing all of the four bidder types that bid on the exchange: state utilities, distribution companies (discoms), private generating companies and industrial plants. Column 3 of the table reports the market share of each strategic seller by their share of offered volume. The largest two sellers, including the largest single seller by a wide margin, at 23 percent market share, are state utilities in the Western region.[27] Industrial plants have small shares of overall market volume but offer significant volume of up to 250 MW in some hours.[28] The largest suppliers in the North region are distribution companies, which the Electricity Act of 2003 permitted to vertically integrate into generation (Thakur et al., 2005).

The estimated marginal costs of these suppliers are presented in column 6. By seller type, the mean cost estimates in ascending order are USD 40.1/MWh for private generating companies, USD 61.5/MWh for industrial plants, USD 67.4/MWh for state utilities and USD 75.5/MWh for distribution companies. The range of cost estimates across sellers is broad. The estimated costs for individual sellers range from a low of USD 14.3/MWh up to a high of USD 121.1/MWh, with both extremes coming from industrial plants. The opportunity cost of supply in the day-ahead market may be different from the pure technological cost of generation for industrial plants, which can alternately use the power themselves. Larger discoms and state utilities have estimated marginal costs in the narrower USD 50/MWh to

[27]There are 151 sellers that offer some quantity during the sample period, and the Herfindahl index for unconstrained offered volume by all sellers is 0.092.

[28]Capacity of 200 MW or more is high, but not unheard of, for a captive generation facility: India had 19 captive plants with above 100 MW of capacity in 2004 (Central Electricity Authority, 2005).

USD 85/MWh range.[29]

Column (5) shows the mean quantity-weighted tick price of bids offered by each bidder, i.e. the average price at which a megawatt is offered. Comparing this column to the estimated costs implies that the average quantity-weighted markup of offered sell ticks is USD 8.5/MWh or 20 percent of marginal cost. Private generating companies have similar absolute markups to other sellers, at USD 11/MWh, but lower costs and therefore larger markups in percentage terms. The estimated marginal costs reflect variation in underlying bids more than in margins (the correlation of estimated costs and weighted mean bid tick prices is 0.91).[30]

These cost estimates are consistent with the available information on generating costs in India. A limitation of the data is that the bidders are anonymous. The generation technology used by each seller is thus unknown and a precise comparison of estimated costs to physical costs is not possible. I therefore benchmark the cost estimates against public data on prices paid for power in the state sector (Central Electricity Regulatory Commission, 2011). The mean energy charges, meant to capture marginal costs, paid to state generating stations under long-term power purchase agreements in 2010, were USD 43.8/MWh for coal stations not at the pit-head, USD 43.9/MWh for natural gas units and USD 93.4/MWh for liquefied natural gas units. These are consistent with the costs I estimate, but for most fuels slightly lower, as the average estimated marginal cost across sellers is USD 63.3/MWh. It makes sense that incremental marginal costs in the short-term market should be slightly higher than these benchmarks, since the state sector costs are for contracts of much greater quantities and longer durations and may rely on low-marginal-cost baseload plants.

From the estimation of marginal costs, a very high cost structure does not appear necessary to rationalize high market prices. Market prices have a mean of USD 87/MWh and a standard deviation of 49/MWh, and transmission constraints routinely create regional differences in price of USD 40/MWh or more. Yet these conditions do not imply, through the model estimates, that costs of supply are unreasonably high overall or in the constrained regions in

[29]Table B7 in Appendix B compares these estimates, which use lagged temperature as an instrument, to estimates that use GMM without correcting for endogeneity. There are generally small differences in estimated costs by methodology. The remainder of the paper, including all counterfactuals, uses these Table 5 instrumental variable estimates.

[30]Note it is possible to estimate costs above weighted mean offered tick price. For example, an industrial plant has bids averaging USD 37/MWh and costs of USD 45/MWh. This seller's average offers are only about half of the market-clearing price. The estimation weights ticks closer to the marginal price, which are more likely to be marginal, more highly, and therefore this seller's cost estimates are higher than its average bid, because the seller's higher bids are much more likely to be marginal.

particular. Cost estimates in this market are in line with energy charges paid to regulated public-sector plants. This leaves market structure, in the form of congestion changing market power, as a leading factor that may account for high prices in the short-term market.

VI.B. Counterfactual Model Fit

Before turning to counterfactual outcomes it is important to understand the fit of the constrained Cournot model in the baseline case without any change in transmission capacity. I briefly describe the model fit here and discuss in more detail in Appendix C.

The model matches market outcomes very well, including the prevalence of transmission constraints and their effects on regional prices (See Appendix Table C8). The North region is import constrained with respect to the West region 17 percent of hours in the model, as against 18 percent of hours in reality. The price difference between these regions conditional on the North price being greater is USD 28.2/MWh in the model and USD 33.7/MWh in the actual market clearance. The North region and West region have similar net demands in the model as in the actual clearance, and these net demands are similarly variable. The fit in the South 1 region is also very good; for example, the difference between South 1 and West prices conditional on congestion is USD 32.9/MWh in fact and USD 39.5/MWh in the model.

VII Counterfactual Transmission Expansions

This section studies counterfactual investments in new transmission capacity into the two most frequently constrained regions, the North and the South. The counterfactuals increase the transmission capacity to each of the North and South 1 regions by up to 1200 MW.

The first part considers the optimal one-step response to these investments in a partial equilibrium model where strategic bidders best respond to the transmission expansion, holding all other bids fixed. This method has the advantage of using the same strategy space as the bids that are offered, but does not allow full equilibrium analysis. The second part considers a full equilibrium response to the transmission expansion using the constrained Cournot model.

VII.A. Optimal One-step Bid Response to Congestion

Here I present a partial equilibrium counterfactual closely related to the optimal bidding condition used in estimation. In the empirical first-order condition (2), bidders set their mark-ups $b_{itk} - C_i'(q_i(b_{itk})) = b_{itk} - \gamma_i$ based on residual demand curves. In this counterfactual, I calculate how the expected residual demand curve for each bidder changes under a particular transmission expansion, holding other bids fixed. I then use the estimated marginal cost $\hat{\gamma}_i$, from Table 5, and modify the first-order condition by adding an additional parameter Δ_{it} so that the mark-up becomes $b_{itk} + \Delta_{it} - \hat{\gamma}_i$. The parameter Δ_{it} is the change in mark-up that sets the moment condition to zero given the change in residual demand induced by the transmission expansion; i.e., the optimal one-step change in bid price. I estimate either a fixed $\Delta_{it} = \Delta_i$ across all hours or $\Delta_{it} = \mathbf{1}\{t \text{ congested}\}\Delta_i$, where the change in bid price only applies during hours that were initially congested. (Initially congested is defined with respect to the region for which the transmission expansion is being done).

Table 6 shows the estimated one-step optimal changes in bid prices for 400 MW transmission expansions into the North region (columns 5 and 6) and the South region (columns 7 and 8). I express the parameter Δ_i as a fraction of the estimated marginal cost for each seller. The first three columns of the table give the characteristics of strategic sellers and column 4 gives the estimated seller marginal costs, all from Table 5. The column 5 and 6 estimates consider Δ_i that is constant and applies in all hours, and the column 6 and 8 estimates Δ_{it} that applies for each bidder only in initially congested hours. The bottom row of the table gives the volume-weighted change in optimal bids.

The main finding in the table is that optimal bid prices decrease significantly under 400 MW transmission expansions. In column 5, if the import capacity to the North region were increased, and bidders were constrained to a single adjustment in all hours, most bidders would decrease their bid prices but by a very small share of cost. The optimal change in bids during congested hours alone, shown in column 6, is much larger, a decrease of 18 percent of marginal cost on average (column 6, last entry). This average decrease comes from four out of the five largest sellers decreasing their bid prices, by 24%, 27%, 45% and 95% of marginal cost (in the case of a low-cost private seller with high initial mark-ups), while only one increases bid prices. These changes in bid prices are statistically different from zero for all these large sellers individually.

A similar pattern of large decreases in optimal bid prices obtains for expansions of transmission capacity into the South region. We see somewhat larger drops in optimal bids when bidders are constrained to a single adjustment in all hours, of negative four percent of marginal cost (column 7). When bidders can adjust separately for constrained hours, they decrease bid prices by twenty percent of marginal cost on average, with the large decrease again due to four of the largest strategic sellers (column 8).

These changes in optimal bids are large and can be benchmarked against both the structural and reduced-form results. The structural estimates are that the average bid mark-up is twenty percent of cost; therefore, the change in optimal bid prices in congested hours due to a 400 MW transmission expansion into either congested region is as large as the average mark-up across the sample. With respect to the reduced-form results, Section III showed that residual demand is less elastic when the grid is congested and that bidders respond to congestion by increasing their bids by USD 8.94 per MWh, about ten percent of the average bid. The one-step counterfactual estimate in Table 6 is -4.84 USD per MWh in the North region (column 6). This structural estimate is somewhat smaller than the reduced-form estimate, as we would expect, because (a) the structural estimate is for a 400 MW expansion of the grid, which will not remove all congestion, (b) the structural estimate is a one-step estimate that does not allow bidders to respond to more elastic bids of other strategic suppliers. Both of these forces will tend to make the optimal changes in bids here smaller than the true optimal change in equilibrium.

The optimal one-step response to transmission expansions therefore confirms the reduced-form evidence that transmission expansions are pro-competitive and produces a point estimate for the optimal change in bid prices which is consistent with the reduced-form evidence.

VII.B. Equilibrium Response to Transmission Expansion

This part considers full equilibrium counterfactuals in response to expanded transmission capacity. Table 7 displays market outcomes with expanded transmission capacity in the Cournot model where the columns show different scenarios for transmission expansion and the groups of rows in the table shows how market prices, quantities and surplus change with the transmission expansion.

Column 2 shows the response of the entire market to a marginal (400 MW) transmission expansion into the North region. This expansion reduces the share of constrained hours by approximately half, from 17 percent to 8 percent. The difference in prices across regions conditional on congestion also falls, and the North region increases its regional net demand by drawing more power from the West. Strategic sellers expand the mean capacity they offer by three percent and market surplus increases by four percent. A 1200 MW expansion into the North region (column 3) nearly eliminates congestion, with the North being constrained only one percent of hours, for a surplus gain of 6.5 percent. Strategic sellers further increase their volume as the West region increasingly sells into the North.

The gains from expansions are greater for transmission expansions into the South region. A 400 MW expansion into the South cuts congestion in half, as in the North, and achieves a 7.4% increase in market surplus, as strategic sellers boost supply by ten percent and sell to higher-value buyers in the South region. Thus the gross return on a marginal 400 MW investment is roughly twice as high into the South. The relaxation of transmission constraints changes the South from a net seller to an importer. A 1200 MW investment into the South is enough to practically eliminate congestion, as in the North, and produces a sixteen percent surge in strategic seller's volume and an eleven percent increase in market surplus, or about USD 7 thousand per hour (column 5 less column 1). In total, the 1200 MW expansions into the North and South regions would increase market surplus by seventeen percent. The estimated gains in surplus are very similar under an alternate set of capacity constraints set at the maximum capacity offered by a firm in the whole sample (Appendix C.4).

Who gains from these investments? Figure 4 divides the gains in surplus across importing and exporting regions and the buy and sell sides of the market. Panel A shows surplus gains from a 400 MW transmission expansion into the North region and Panel B a like expansion into the South region. In each panel, the three bars grouped on the left represent changes in surplus for buyers (grey), sellers (light grey) and both sides together (black) in the importing region, while the three bars on the right represent changes for the exporting region. In the North region, in Panel A, the losses to sellers (light grey, left group), who lose market power as import capacity grows, outweigh the gains to buyers from lower prices (grey bar, left group), so the net surplus change in the region is slightly negative. That is, the highly import-constrained North region would in sum prefer that the constraint not be relaxed. This small net loss in surplus is offset by large gains to sellers in the exporting regions, which benefit from higher prices and quantity after they are integrated with the high-demand North (light grey, right group). The pattern of gains for an import expansion into the South region, in Panel B, is similar, though in this case the gains to buyers within the South (4.9 percent of baseline surplus) outweigh the losses to sellers from being undercut (2.2 percent).

Thus most of the surplus gains from new transmission accrue to sellers in exporting regions, who are able to supply more and at higher prices. This observation is consistent with the earlier partial equilibrium finding from Table 6 that the greatest cuts in optimal bid prices were for high-volume strategic sellers in the West region. Overall, importing regions have modest net gains in surplus because undercutting sellers' market power and hence surplus offsets gains to the buy side from lower prices and greater quantity.

VII.C. Costs of Infrastructure for Transmission Expansion

The above estimate of social benefits, or increased surplus, from transmission expansion does not account for the costs of building the needed infrastructure. To estimate the net change in surplus from transmission expansion I therefore develop a measure of the costs of marginal transmission capacity to compare to the above measure of benefits.

The method of estimating marginal expansion costs has three steps. First, I identify the physical lines that form binding constraints on inter-regional flow during my study period. Second, I use planning documents to ascertain what more would have had to be built to relieve these constraints. Because elements of the grid such as transmission lines and substations are interdependent, the marginal investment required to relieve constraints is above the replacement cost of the constrained grid links. Third, I use regulatory rulings on the costs of existing grid elements to estimate the cost of the marginal expansion proposed. The transmission system is regulated under a cost-plus regulatory regime so the regulator commonly rules on the cost of grid elements similar to those needed for the expansion.[31]

Table 8, using this method, summarizes the annualized costs and benefits of marginal (400

[31] The estimation of costs can be illustrated with the example of an expansion of the capacity from the East Region to the North Region. The system operator stated, in monthly reports on available transmission capacity, that a transmission link between Farakka and Malda was the constraint on congestion across these regions (Power Grid Corporation of India Limited, 2009). The system operator has developed a plan to circumvent this constraint by building an additional high-voltage line from Rajarhat, near Kolkata, to Purnea along with associated infrastructure (National Load Dispatch Centre, 2012). I take the cost of the planned grid elements from recent regulatory filings for comparable expansions and apply the costs of these elements to the expansion plan (Central Electricity Regulatory Commission, 2012*a*). Costs include depreciation, interest and operations and maintenance expenses and are presented on an annual, amortized basis. I exclude the regulated return on equity, which is not a social cost, from cost calculations.

MW) expansions in transmission capacity on the East-to-North and East-to-South links.[32] The table shows the annual cost of constructing the needed grid elements to expand transmission capacity between regions and the ratio of the gains in market surplus to those costs. I find that marginal transmission expansion on these links would have benefit-cost ratios of 1.85 and 2.74, respectively, both well above one, the ex post break-even level of social returns. These proposed marginal investments have a much higher social return than the 16 percent private return on equity, i.e. a benefit-cost ratio of 1.16, allowed by the regulator for investment in transmission capacity. Moreover, as the marginal benefits for transmission expansion to the South region flatten out only gradually, additional expansion of this link would also yield benefits exceeding costs by a large amount.

VII.D. Interpretation of Net Surplus Gains

The comparisons above rely on several broad assumptions that, on balance, probably understate the benefits of transmission investment.

First, I do not model the contract market and omit any potential gains from trade in that market from my counterfactuals. The first-come, first-serve rule for allocating transmission capacity across segments implies that there is transmission capacity available in the overall electricity market if and only if there is capacity available in the day-ahead market. Therefore, a marginal expansion of transmission capacity for the day-ahead market is the same as an expansion for the whole sector, unless the expansion is great enough to relax constraints that had bound in segments cleared before the day-ahead market. In 22 percent of constrained hours into the South and 37 percent into the North, no transmission capacity (0 MW) is available for the day-ahead market. When capacity runs out, this implies that all the capacity has been booked in the earlier contract market, which would also have been constrained and may then have directly benefited from transmission expansions. Moreover, if relaxing transmission constraints caused buyers and sellers to shift trade out of the bilateral contract market, which is currently favored in the transmission allocation process, and into the day-ahead market, there may be further gains from increased market liquidity and efficiency (Mansur and White, 2012).

Second, surplus is based on wholesale bids including bids from distribution companies.

[32] Transmission capacity is typically measured in units of potential (kilovolts); I assume 1 kV of line can transmit 1.25 MW of energy to express capacities in energy terms instead.

These distribution companies are state agents bidding on behalf of retail customers, and I take the valuations in their wholesale bids as the social value of that electricity. Given the distorted state of retail supply in India, this assumption could either overstate or understate surplus depending on what customers are being rationed at the margin. Urban consumers cut-off by discoms often run generators at a marginal cost of supply 50 percent or 100 percent above the wholesale market price, yet rural and agricultural consumers face marginal prices far below cost or no marginal price at all. Thus, observing only the wholesale bidding data and not *who* receives the power, it is not possible to say whether wholesale valuations are too high or too low, relative to retail valuations.

Third, I treat only a subset of thirteen large sellers as strategic and hold the bids of all non-strategic sellers fixed. This assumption tends to understate the changes in market outcomes under transmission expansion, to the extent that fringe sellers would also have changed their behavior in an unconstrained market.

Fourth, gains during the sample period and investment costs are annualized and assumed constant over time. The benefits of capacity expansion assume no growth in the day-ahead market and no long-term benefits from transmission expansion in terms of better locational choices of new power plants, on the supply side, or industrial plants, on the demand side. There may be substantial long-term benefits from transmission lowering generation costs if it reduces the need for supply to co-locate with demand. Transmission also increases grid reliability, which is a high policy priority in India since transmission constraints have caused vast power outages.[33]

VIII Conclusion

I study the potential benefits of greater integration in the Indian electricity market. I provide a progression of evidence on the competitive effects of grid congestion on firm behavior and market outcomes. First, common grid congestion gives suppliers the opportunity and incentive to raise prices. Second, sellers do in fact raise prices during congested hours, of a magnitude

[33] India experienced the largest blackout in history, in late July 2012, which brought down the Northern Indian grid for two days, cutting off power to states with a population of 670 million. This collapse was not due to excessive demand, as widely reported in the press (Yardley and Harris, July 31, 2012), but a transmission problem. Suppliers in the export-constrained West region of the grid were supplying too *much* power, despite a transmission corridor being down for maintenance, causing power flows to exceed the line capacity and trigger a cascading series of failures in the entire Northern-Eastern-Western grid (Central Electricity Regulatory Commission, 2012*b*).

somewhat larger than what a partial equilibrium model would predict. Third, the main finding of the paper, counterfactual increases of transmission capacity into the most congested regions of the grid increase market surplus by 17 percent in equilibrium. This gain in surplus is large enough to cover the costs of investment and due in part to the competitive effects of such transmission on the supply offered by strategic firms.

A natural question is why these lines, with positive social returns, have not already been built. One answer is that, given the rapid change in the Indian electricity sector, it is hard to anticipate the value of infrastructure in a new power market. In this view, the congestion here is a costly but temporary disequilibrium to be remedied as the government continues to expand transmission capacity (Central Electricity Authority, 2012*a*). This answer does not seem entirely satisfying, since the patterns of transmission constraints studied here are fairly long-lived; for example, the North Region and South Region are import constrained as or more frequently in data from 2014 as in the study sample four years earlier. Another answer is that transmission planners are not accounting for the competitive effects of transmission. The returns to transmission investment are set by cost-plus regulation, so merchant transmission projects earn a fixed rate of return on investments deemed useful, which does not vary based on the potential gains from trade or price differences across the regions a project will connect. They do not account, in particular, for whether a line may be critical to inter-regional competition.

To my knowledge this is the first econometric study of power market conduct in a developing country. In deregulated electricity markets in developed countries, the exercise of market power affects productive efficiency, but not allocative efficiency (Joskow, 2008). When a generator withholds capacity that would be competitive to operate, in order to raise prices, less efficient plants are called to make up the gap, and consumers are served in any case. Market power is less studied but potentially more important for welfare in developing countries. In India's market, where the demand side at the wholesale level is often rationing power at the retail level, withholding power may instead increase demand not met, from any source. This rationing of power reduces the productivity of firms (Allcott, Collard-Wexler and O'Connell, 2016; Fisher-Vanden, Mansur and Wang, 2012) and surely harms consumers as well. An important direction for research is therefore to understand the pass-through of wholesale market outcomes to the people and firms that need reliable power.

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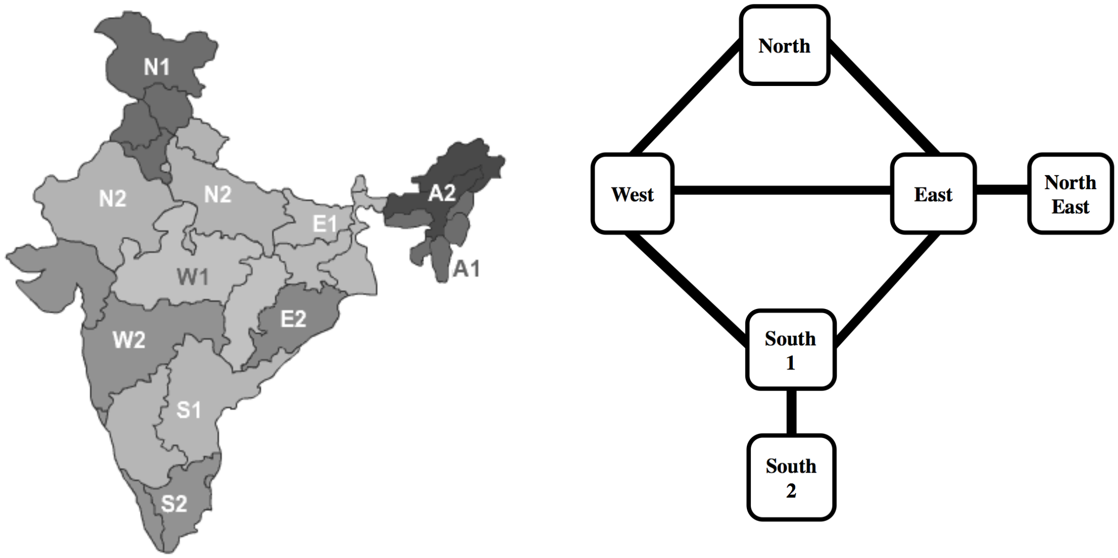
IX Figures

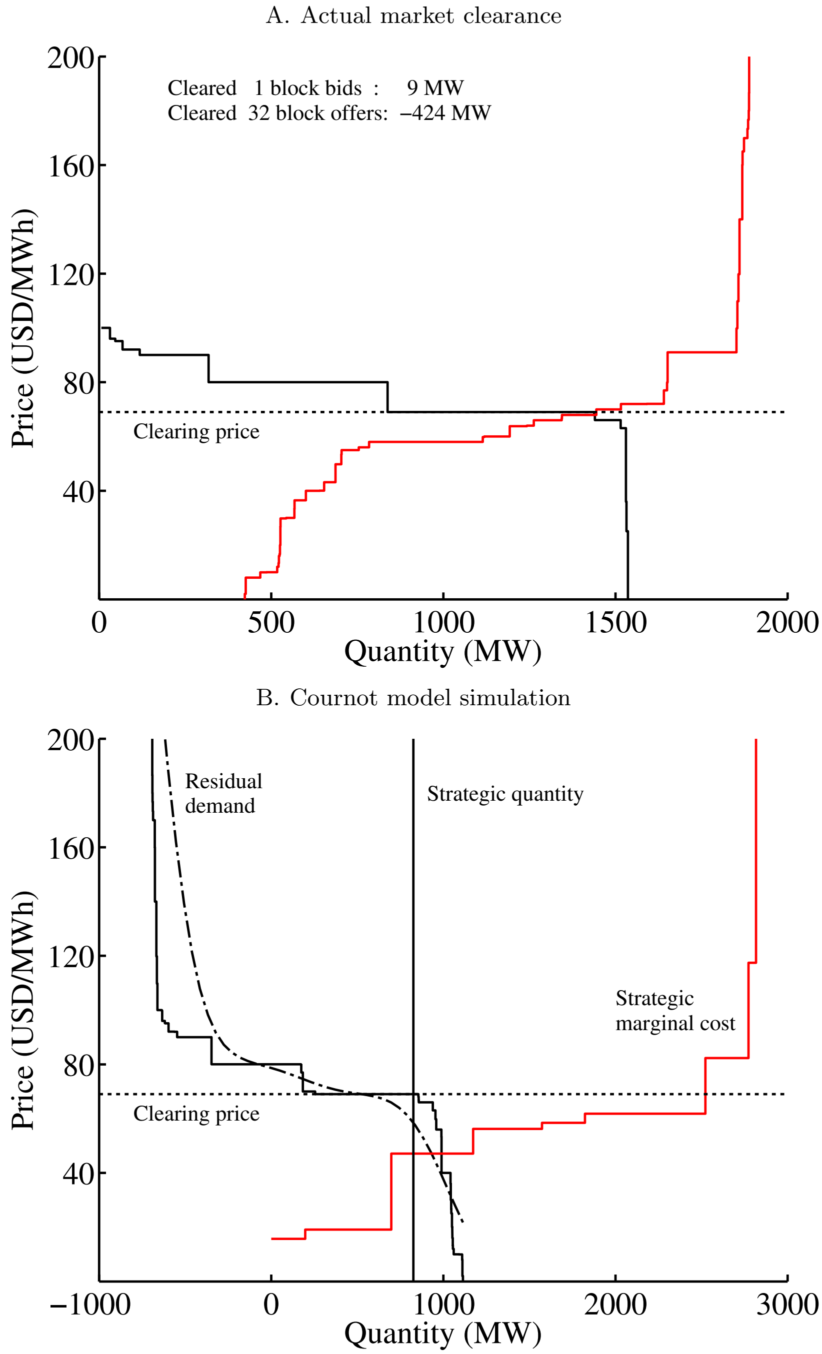
Figure 1: Indian Power Grid

A. Power Exchange Bidding Areas B. Schematic of Ever-constrained Regions



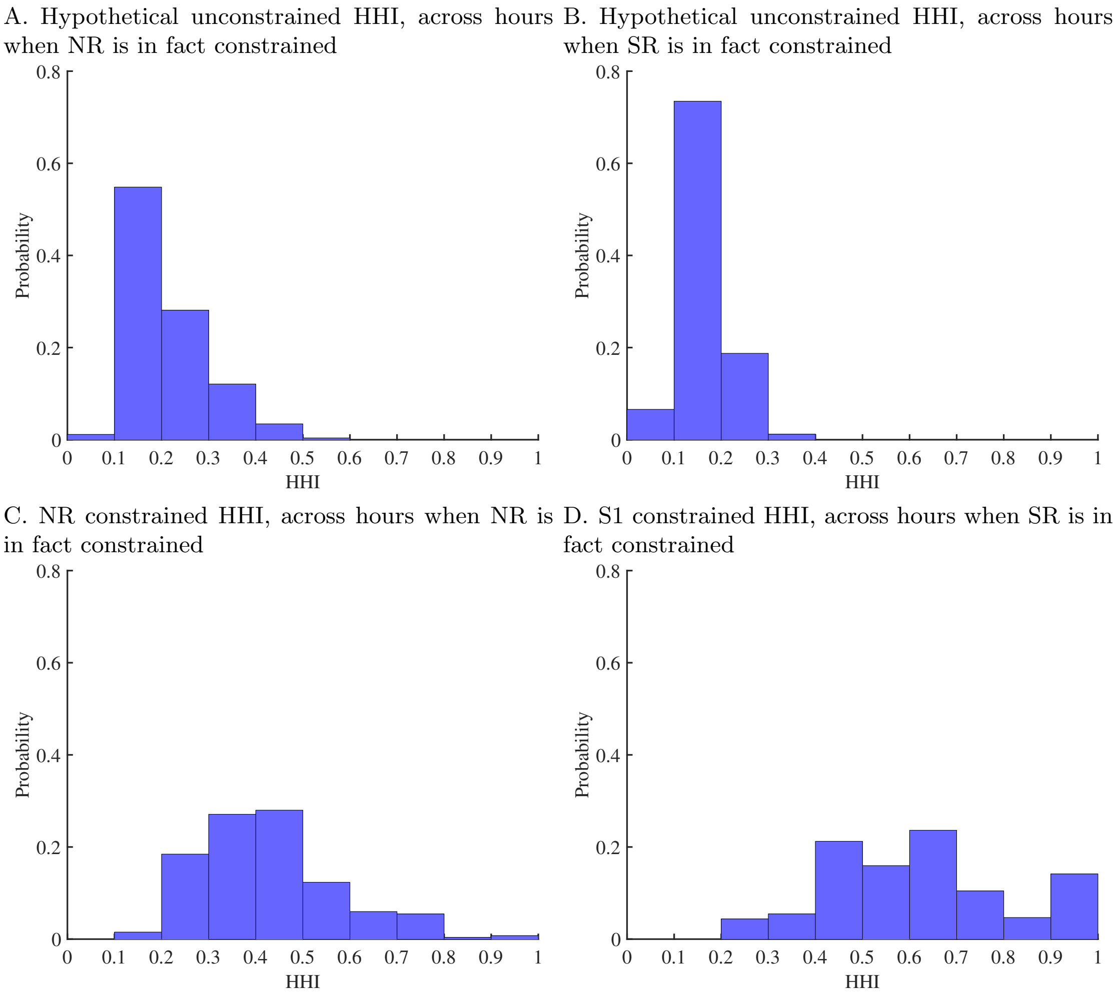
The figure shows geographic and schematic representations of the bidding areas in the Indian day-ahead power market. Panel A represents the ten subregions in which bids are submitted, formed from five regions with two subregions apiece. Panel B represents the six functionally distinct regions that are ever separated by constrained transmission links and the structure of interregional transmission links amongst them.

Figure 2: Unconstrained Market Clearance
January 26th, 2010, hour 17



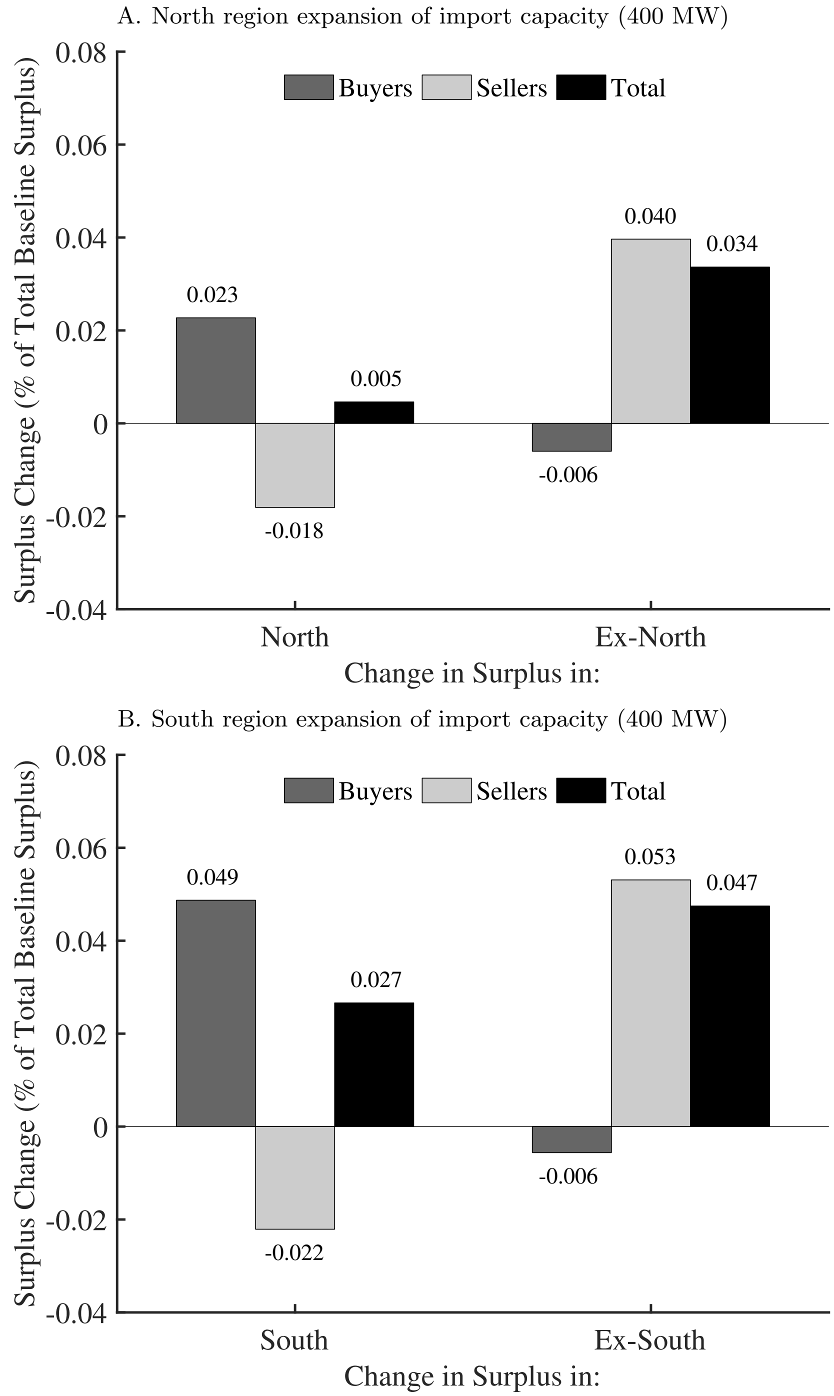
The figure shows the unconstrained market clearance on the Indian Energy Exchange during January 26th, 2010, hour 17. Panel A shows the actual market-clearing price as determined by the intersection of the downward-sloping demand curve and upward-sloping supply curve, where each curve has been shifted relative to the vertical axis by the volume of cleared buy and sell block bids, respectively. Panel B shows the determination of the simulated market-clearing price. The downward-sloping solid line is the residual demand curve consisting of demand and fringe supply bids and the dashed-and-dotted line a kernel-smoothed representation of this curve. The upward sloping solid line is the aggregate marginal cost curve of the strategic suppliers. The vertical line is the aggregate quantity offered by the strategic suppliers in equilibrium. The equilibrium is determined by the slope of the smoothed residual demand curve but the clearing price, which in this case is the same as the actual clearing price, is determined by the intersection of the strategic quantity with the true residual demand curve.

Figure 3: Market Concentration by Transmission Constraint Status



The figure shows the distribution of the Herfindahl-Hirschman Index (HHI) of market concentration when transmission constraints do not bind (top row) and bind (bottom row). The HHI is based on sellers' offered volumes. The sample is restricted to hours in which the North Region is constrained from the rest of the grid (Panels A and C), or in which the South Region is constrained from the rest of the grid (Panels B and D). The HHI is then computed, using the same offered volumes, either only in the constrained region (North in Panel A, South in Panel B), or within the grid as a whole (Panels C and D). The comparison is not between hours when the grid was constrained and hours when it was not, but between concentration in hours when the grid was constrained and concentration, in the same sample of hours and with the same bids, had the grid not been constrained (i.e., if more transmission capacity was built).

Figure 4: Counterfactual Surplus by Region and Side of Market



The figure shows the division of changes in surplus for counterfactual increases of transmission capacity across regions and sides of the market under strategic Cournot conduct, where bids respond to the expansion of transmission. Panel A shows expansions of 400 MW capacity into the North region and Panel B into the South region. In each panel, the three bars grouped on the left represent changes in surplus for buyers (blue), sellers (red) and both sides together (black) in the importing region, while the three bars on the right represent changes for the exporting region. Each surplus measure is scaled by subtracting the baseline surplus for each group and dividing by the total surplus. Each 0.05 share of total surplus represents an annual change of USD 27 million (INR 1.36 billion).

X Tables

Table 1: Market and Bid Summary Statistics

	Mean (1)	Std. Dev. (2)	Min. (3)	Median (4)	Max. (5)	Obs. (6)
Panel A. Summary Over Hourly Auctions						
Unconstrained price (USD/MWh)	87.06	48.52	1.99	79.99	278.01	4344
Buy bids (number/auction)	19.25	8.61	4.00	18.00	48.00	4344
Sell bids (number/auction)	24.70	6.04	12.00	25.00	54.00	4344
Panel B. Summary Over Sell Bids						
Sell bid ticks (number/bid)	1.84	2.09	1.00	1.00	22.00	107304
Sell bid tick prices (USD/MWh)	67.46	45.27	0.51	60.00	300.00	107304
Sell bid tick quantities (MW)	33.73	67.47	0.25	9.10	1000.00	107304

Summary statistics for bidding in the day-ahead market from November, 2009 through April, 2010. Panel A shows summary statistics for auction outcomes and participation, averaged over all hourly auctions in the sample period. Panel B shows summary statistics for sell bids over all sell bids offered in these auctions. Bids are step functions and tick quantities are incremental quantities for each step alone.

Table 2: Prevalence of Congestion

	Northeast (1)	East (2)	North (3)	South 1 (4)	South 2 (5)	West (6)
Panel A. Row Price Higher than Column (%)						
Northeast		0.2	0.2	0.1		0.5
East	0.4					0.3
North	18.5	18.1		17.8	17.4	18.2
South 1	23.5	23.1	23.0			23.3
South 2	26.7	26.3	26.2	7.1		26.4
West	0.4					
Panel B. Row Price less Column Price, Conditional on Being Higher						
Northeast		14.9	7.7	5.6	2.0	12.4
East	107.0					10.3
North	35.4	33.8		34.1	34.7	33.7
South 1	34.3	33.1	33.0			32.9
South 2	37.1	36.2	36.1	26.2		36.1
West	107.0					

Summary statistics for congestion on the day-ahead market from November, 2009 through April, 2010. Panel A shows the percentage of hours during this period when the region labeling the row had a price greater than the price of the column region. Panel B shows the row region price less than column region price conditional on the row region price being greater. The mean unconstrained market-clearing price, a point of reference, is USD 87.06/MWh over the sample period.

Table 3: Transmission Constraints and Market Competitiveness

	Median when region in panel is:	
	Unconstrained	Constrained
	(1)	(2)
Panel A. North Region		
HHI in connected area	0.19	0.41
Slope of residual demand (MWh/USD)	-22.01	-15.03
Elasticity of residual demand (%)	-8.60	-3.15
Panel B. South Region		
HHI in connected area	0.16	0.63
Slope of residual demand (MWh/USD)	-25.13	-10.95
Elasticity of residual demand (%)	-36.61	-12.47

The table shows summary statistics on market concentration by whether transmission constraints bind, for the North Region (Panel A) and South Region (Panel B), respectively. The sample for each panel consists of hours in which, at the actual market clearance, the panel region was constrained from (i.e., had higher prices than) the rest of the grid. The two columns of the table show statistics on market concentration calculated under these constraints (column 2) and ignoring these constraints (column 1); column 1 is therefore counterfactual in that constraints actually did bind in these hours. The three rows of each panel each show the median of a statistic on market concentration. The first row shows the Herfindahl-Hirschman Index (HHI) of offered sell volumes amongst all sellers in the grid (column 1) or within the constrained region (column 2). The second row shows the slope of residual demand faced by the largest seller in the region, evaluated at a fixed offered quantity (ninety percent of that seller's capacity) in both unconstrained and constrained scenarios. The third row shows the corresponding elasticity of residual demand evaluated at the same point. Block bids are cleared at either unconstrained or constrained market prices, for each column, and the residual demand in the constrained scenario is shifted in by the import capacity of the constrained region.

Table 4: Bid Prices and Congestion

Dependent variable:	Price bid				Congestion
	OLS	OLS	OLS	2SLS	First Stage
	(1)	(2)	(3)	(4)	(5)
North region congested (=1)	7.86***	8.15***	6.38***	8.94***	
	(1.07)	(1.43)	(0.63)	(2.19)	
North import capacity (100 MW)					-0.034***
					(0.0046)
Month effects	Yes				
Date effects		Yes	Yes	Yes	Yes
Hour quartic	Yes	Yes	Yes	Yes	Yes
Temperature deciles	Yes	Yes	Yes	Yes	Yes
Bidder effects			Yes	Yes	Yes
Bidder X Quantity quadratic			Yes	Yes	Yes
Mean in uncongested hours	95.56	95.56	95.56	95.56	
Observations	141455	141455	141455	141455	141455

The table shows regressions of bid prices on congestion with observations at the bid-tick level. The sample consists of all supply offers within the North Region for hourly auctions in the period from November, 2009 through April, 2010. The dependent variable is the price of a bid tick in USD per MWh. Observations are weighted by tick quantity so that the coefficients represent the change in the average price of a MWh bid. The explanatory variable of interest is whether the North Region is import constrained in a given hour. The control variables in various specifications include month and date effects, a quartic polynomial in hour of day, dummy variables for deciles of the temperature distribution in the North Region, bidder fixed effects, and bidder-specific linear and quadratic terms in the offered quantity of a bid. Columns 1 through 3 are estimated by ordinary least squares. Column 4 is estimated by two-stage least squares where the instrument for congestion is the transmission capacity available for short-term open access imports into the North Region in MW. Robust standard errors clustered by date are in parentheses with * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 5: Strategic Seller Characteristics and Estimated Marginal Costs

Region	Type	Share of Vol. Off. (%)	Maximum Vol. Off. (MW)	Wtd. Mean Tick Price (USD/MWh)	Estimated Marginal Cost (USD/MWh)	Std. Err. (USD/MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
North	State Utility	2.29	700	93.34	84.42	(6.93)
North	Discom	7.67	1000	60.41	57.47	(2.80)
North	Discom	6.56	500	73.39	68.91	(4.49)
North	Discom	1.07	475	87.54	100.01	(7.61)
West	State Utility	22.73	400	73.20	64.32	(1.55)
West	State Utility	10.90	250	48.46	39.98	(1.14)
West	State Utility	2.52	250	91.32	80.90	(2.02)
West	Private Genco	8.06	480	35.98	20.58	(1.32)
West	Private Genco	3.83	65	66.85	59.68	(1.01)
West	Industrial Plant	1.46	44	109.98	65.64	(3.43)
West	Industrial Plant	1.36	36	132.39	121.05	(3.94)
West	Industrial Plant	1.22	250	36.57	45.06	(0.76)
West	Industrial Plant	1.03	198	14.90	14.32	(2.12)

Statistics for bidding by strategic sellers on the day-ahead market from November, 2009 through April, 2010 and estimated marginal costs. Region is the region in which the seller bids, type is the category of bidder to which the seller belongs, share of total volume offered is the share of offered volume offered by each seller, weighted mean tick price is the quantity-weighted average price of bid ticks offered by the seller, estimated marginal costs are the costs recovered via the estimation described in Section V, using lagged temperature to instrument for the estimation moments. Standard errors are bootstrapped by resampling 100 bootstrap iterations with replacement over both days in the sample and simulated market outcomes. Strategic sellers are those sellers in the North and West region with at least one percent market share as determined by the share of offered volume.

Table 6: Counterfactual One-Step Changes in Optimal Mark-ups

Region	Type	Share of Vol. Off. (%)	Estimated Marginal Cost (USD/MWh)	Transmission expansion to: North		South	
				All hours	Congested	All hours	Congested
				Estimated Change in Optimal Bid (% of marginal cost)			
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
North	State Utility	2.3	84.42	2.17	-1.04	0.80	-5.74
			(6.93)	(11.91)	(8.51)	(11.37)	(8.24)
North	Discom	7.7	57.47	-2.78	-24.01	-5.69	-23.41
			(2.80)	(6.41)	(7.89)	(6.98)	(5.99)
North	Discom	6.6	68.91	-1.04	-27.11	-4.16	-27.10
			(4.49)	(8.60)	(11.52)	(9.39)	(8.62)
North	Discom	1.1	100.01	0.15	8.58	-0.58	7.82
			(7.61)	(10.68)	(10.26)	(11.68)	(8.59)
West	State Utility	22.7	64.32	-1.39	13.15	-5.85	2.30
			(1.55)	(3.25)	(3.85)	(3.33)	(2.96)
West	State Utility	10.9	39.98	0.75	-45.12	0.06	-48.61
			(1.14)	(3.90)	(4.87)	(3.84)	(4.37)
West	State Utility	2.5	80.90	-0.47	8.29	-5.32	6.97
			(2.02)	(3.38)	(5.90)	(3.20)	(6.02)
West	Private Genco	8.1	20.58	-0.25	-95.91	-9.14	-85.47
			(1.32)	(7.88)	(22.11)	(8.67)	(28.48)
West	Private Genco	3.8	59.68	-0.76	1.36	-2.55	-0.20
			(1.01)	(2.22)	(2.24)	(2.63)	(2.48)
West	Industrial Plant	1.5	65.64	-0.87	2.64	-12.84	-0.36
			(3.43)	(6.36)	(27.90)	(7.46)	(26.96)
West	Industrial Plant	1.4	121.05	-0.11	11.21	2.00	7.21
			(3.94)	(4.52)	(4.81)	(4.57)	(4.17)
West	Industrial Plant	1.2	45.06	0.12	-0.50	0.42	-0.68
			(0.76)	(2.53)	(1.88)	(2.60)	(1.90)
West	Industrial Plant	1.0	14.32	-1.67	8.46	-0.88	55.35
			(2.12)	(20.04)	(26.51)	(21.59)	(27.80)
Volume-weighted mean change in optimal bid				-0.78	-17.93	-4.46	-20.45

The table shows estimates of the change in optimal bid prices due to counterfactual transmission expansions. Optimal bids are one-step optimal, in that the optimal bid prices respond to the change in residual demand induced by transmission expansions, but do not iterate to respond to changes in the bids of other strategic sellers in turn. The sample consists of all supply offers within the North Region for hourly auctions in the period from November, 2009 through April, 2010. Columns 1 through 4 are replicated from Table 4, columns 1 through 3 and 6, respectively, and described in the notes for that table. Columns 5 through 8 are the changes in mark-ups, expressed as a percentage of that seller's marginal cost, required for the seller's first-order conditions for optimal bidding to be satisfied under transmission expansions. The counterfactual transmission expansions considered are a 400 MW expansion into the North region (columns 5 and 6) or the South region (columns 7 and 8). In columns 5 and 7 we estimate a single change in mark-ups across all hours; in columns 6 and 8 we estimate a single change in mark-ups across only those hours in which the region undergoing transmission expansion was initially congested. Standard errors in parentheses.

Table 7: Counterfactual Cournot Outcomes with Expanded Transmission Capacity

		North		South	
Transmission expansion	None	400 MW	1200 MW	400 MW	1200 MW
	(1)	(2)	(3)	(4)	(5)
Regional Prices					
North > West (% of hrs)	0.17	0.08	0.01	0.17	0.18
North − West (USD/MWh)	29.92	25.85	28.86	29.21	29.19
South 1 > West (% of hrs)	0.31	0.30	0.30	0.09	0.01
South 1 - West (USD/MWh)	38.91	38.57	38.58	29.07	20.43
Quantity (MW)					
North net demand	325.80	386.81	421.46	278.61	250.54
South 1 net demand	-82.43	-85.83	-86.55	-31.89	12.16
West net demand	-431.24	-478.93	-507.68	-471.67	-489.43
Strategic seller cleared	603.73	619.43	630.27	665.81	699.56
Surplus (USD '000s)					
Market	58.49	60.73	62.29	62.82	65.08
Buyer's	19.70	20.67	22.48	22.22	24.07
Seller's	38.79	40.05	39.81	40.60	41.00

The table shows counterfactual market outcomes under different increases in transmission capacity, using the constrained Cournot model. The counterfactual scenarios, across columns, are (i) no change in transmission (baseline case) (ii) 400 MW expansion to the North region (iii) 1200 MW expansion to the North region (iv) 400 MW expansion to the South region (v) 1200 MW expansion to the North region. The groups of rows in the table show how market prices, quantities and surplus respond in each scenario. The notation North − West (USD/MWh) means the difference in the respective regional prices conditional on congestion.

Table 8: Estimated Cost of Transmission Capacity Expansions into North and South Regions

	Annual Cost/Benefit (USD millions)	Planned Grid Element	Source of Cost Estimate
	Panel A. North region capacity expansion of 400 MW		
Amortized cost	1.70	2 X 500 MVA Substation	Pet. No. 89/2012, Jaipur South
	3.50	2 X 200 kVA Line-in Line-out	Pet. No. 89/2012, Jaipur South
	5.40	450 km 400 kV Line Rajarhat-Purnea	Pet. No. 96/2008, RAPP-Kankroli
	10.60		
Annual surplus	19.62		
Ratio of surplus/cost	1.85		
	Panel B. South region capacity expansion of 400 MW		
Amortized cost	11.28	1600 km HVDC Line and Stations Talcher-Kolar	Pet. No. 84/2005, Talcher-Kolar
	2.58	400 kV DC Talcher-Rourkela	Pet. No. 146/2010, Talcher-Rourkela
	13.86		
Annual surplus	37.93		
Ratio of surplus/cost	2.74		

The table presents a cost-benefit analysis of new transmission investment to relieve congestion from the East to the North Region and the East to the South Region. The grid elements to be constructed in order to relieve congestion are from National Load Dispatch Centre (2012) and Power Grid Corporation of India Limited (2009). The grid elements to relieve congestion into the North Region are part of an explicit plan from the system operator (NLDC) while the grid elements to relieve congestion into the South Region are inferred from the planning and transmission capacity documents. Cost estimates for each grid element are from granted petitions for cost reimbursement for comparable grid elements filed with the Central Electricity Regulatory Commission (CERC), available at www.cercind.gov.in/orders.html. Cost estimates are on an annual, amortized basis and include depreciation, interest and operations & maintenance costs but not return on equity. The length of the Talcher II-Rourkela link is from the petition cited in the table but the cost of building the line is computed at the higher rate given in Pet. No. 96/2008. All costs are scaled to represent a 400 MW capacity expansion. Annual surplus is the total gain in market surplus each year in the day-ahead market from a 400 MW transmission expansion into each region, calculated by assuming the gain in surplus over the sample period of November, 2009 through April, 2010, as in Table 7, would remain constant.

A Appendix: Institutions

A.1 Real-time Balancing through Unscheduled Interchange

The prices for real-time balancing, called unscheduled interchange in the Indian market, depend on the grid frequency, which in turn depends on the balance between demand and supply on the grid. When demand exceeds supply, as is often the case, the grid frequency drops below its nominal frequency of 50 Hz and sellers (buyers) are paid for injecting more (drawing less) power than scheduled. This mechanism takes the place that real-time balancing markets with advance bidding serve in other power systems.

The balancing or UI price is a piecewise linear function of grid frequency. As part of a general effort to prevent buyers and sellers from relying on UI and to improve the balance of demand and supply, which affects grid stability, the relationship between the UI price and the grid frequency has become steeper over time. On April 1st, 2009 the price schedule was increased so that the UI price increased by USD 3.1/MWh (INR 155/MWh) for each 0.02 Hz change in grid frequency and on May 1st, 2010 increased again to USD 4.3/MWh (INR 215/MWh) for each 0.02 Hz change. The net effect of these changes has been to discourage over-demand through UI and push buyers and sellers back into the scheduled markets.

There are also regulatory limitations on the use of UI designed to prevent withholding from the scheduled power markets. The UI charges paid to sellers are capped and the maximum allowable deviation from schedule also capped (Central Electricity Regulatory Commission, 2009) The UI regulation also explicitly threatens sellers that persistently deviate from schedule with regulatory action.

A.2 Arbitrage between short-term market segments

Appendix Table A1 shows the correlations between prices across the different short-term market segments at hourly (Panel A) and weekly (Panel B) frequencies. The sample period is 2009 and 2010. The prices are as follows. For the day-ahead market, the unconstrained hourly clearing prices on the Indian Energy Exchange and the Power Exchange India, the two exchanges that make up all trade. For the balancing market, the unscheduled interchange price, calculated by applying the UI Regulations' administered price schedule to the grid frequency. We take the average of the UI price for the Northern-Eastern-Western (NEW) grid and the Southern grid. For contracts, we take the volume-weighted average price of all single-day short-term contracts (signed between 365 and one day in advance of delivery), across all regions of the grid. The timing of the prices is lined up across markets based on the date of delivery of electricity; therefore, because contracts are signed at various times in advance, the contracts may have been agreed up to one year prior to delivery (though most are agreed within a month before delivery).

Table A1: Price Correlations Across Short-term Market Segments

	IEX (1)	PXI (2)	Balancing (3)	Contracts (4)
Panel A. Hourly Frequency				
Day-ahead price, IEX, unconstrained	1			
Day-ahead price, PXI, unconstrained	0.915^{***}	1		
Balancing price (unscheduled interchange)	0.598^{***}	0.602^{***}	1	
Panel B. Weekly Frequency				
Day-ahead price, IEX, unconstrained	1			
Day-ahead price, PXI, unconstrained	0.978^{***}	1		
Balancing price (unscheduled interchange)	0.808^{***}	0.824^{***}	1	
Short-term contract weighted average price	0.714^{***}	0.774^{***}	0.664^{***}	1

The table shows correlations between market prices on various short-term Indian power markets at hourly (Panel A) and weekly (Panel B) frequencies. The prices are as follows. For the day-ahead market, the unconstrained hourly clearing prices on the Indian Energy Exchange and the Power Exchange India, the two exchanges that make up all trade. For the balancing market, the unscheduled interchange price, calculated by applying the UI Regulations' administered price schedule to the grid frequency. The balancing or UI price is a piecewise linear function of grid frequency. We take the average of the UI price for the North, East and Western grids (NEW) and the Southern grid. For contracts, we take the volume-weighted average price of all single-day short-term contracts (signed between 365 and one day in advance of delivery), across all regions of the grid. The sample period is 2009 and 2010. The symbol * denotes $p < 0.05$, ** $p < 0.01$ and *** $p < 0.001$ for a test of the null that the correlation between the row and column price series is zero.

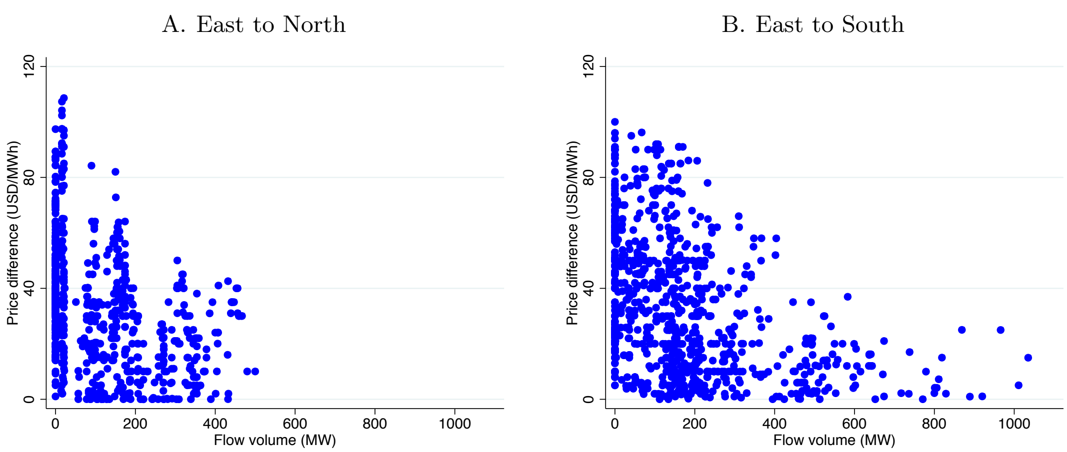
A.3 Transmission allocation and congestion

The transmission capacity limits determined by the NLDC are allocated among the different segments of the power market in an administrative manner. Long-term customers, which are charged for building and maintaining the transmission grid in proportion to their generation capacity, are given first priority (Central Electricity Regulatory Commission, 2008*b*). The allocation of capacity to long-term trade is nearly constant over time. The margin left after long-term use, due to design margins, short-term variation in power flows and spare transmission capacity due to anticipated future load, is left to short-term trade including both contracts and the day-ahead market (Central Electricity Regulatory Commission, 2008*a*).

Short-term contractual buyers may book up the corridor that has been reserved for short-term trade on a first-come, first-served basis before the power exchanges. This reservation of the corridor continues until three days prior to the day of delivery, at which time bookings are frozen and the remaining transmission capacity reserved for use by power exchanges. On average, of the corridor that is available for short-term use, more than half is left over for use by the power exchanges. However, in some hours short-term contracts use up all the corridor for short-term trade, in which case power exchanges must solve for market clearance with zero flows between the regions where corridor has been exhausted.

The above transmission allocation process means that, although the amount of physical transmission line does not vary, the amount available for use by the day-ahead market does vary. This variation in available capacity is not exogenous to market conditions, since it depends on how much corridor has been booked up by contract market participants. We may still be interested to see, on this intensive margin, how the severity of transmission constraints is correlated with regional price differences.

Figure A1: Regional Price Differences Against Interregional Flows



The figure plots the price difference between two regions against the power flow between two regions for the East to North and East to South corridors respectively, conditional on a transmission constraint between each pair of regions binding, during the sample period of November, 2009 through April, 2010. The price difference is the South or North price less the East price and the flow the net supply from the East region. A constraint binding implies that the price difference is weakly positive.

Figure A1 charts regional price differences against inter-regional power flows for the East and North regions (Panel A) and the East and South 1 regions (Panel B). The horizontal axis shows the flow between regions, with positive flow indicating the net supply from the East region, and the vertical axis shows the difference between the North or South 1 price and the East price. The panels show only hours when the flow between regions is constrained, causing the constrained areas including each region to be cleared separately and the market-clearing prices in the two regions to differ.[34] As shown in Panel A, power flow being constrained at low levels, below 200 MW, is associated with price differences of USD 100/MWh or above in both regions. These price differences across regions are larger than the average unconstrained clearing price. When more transmission capacity is available, the greater flow between regions eliminates or reduces the price difference, creating the strong negative correlation between price differences and constrained flow in the figure. A similar pattern of price differences decreasing in constrained flow is seen between the South 1 region and the East (Panel B), though a greater flow is needed to close the price gap for this pair.

A.4 Contract positions and congestion in the day-ahead market

The analysis uses data from the day-ahead market and assumes that contract positions are exogenous, from the perspective of a firm bidding in the day-ahead market. This section uses data from the short-term contract market to argue that this assumption is reasonable, over a short time horizon, since contracts are not updated in response to congestion at high frequency.

The contract data were obtained from the CERC under a non-disclosure agreement. The data cover all short-term contracts (less than 365 days) for the three fiscal years running from April 1st, 2009 through March 31st, 2012. This period encompasses the sample period used in the analysis of the day-ahead market. The variables include the dates and hours to which the contract applies, the quantity and price and the region of the buyer and seller. The contract data, like the day-ahead bidding data, are anonymized and therefore cannot be linked to the bidding data to learn the contract positions of individual firms.

[34] Note that the constraints bind at different levels of flow. The available physical capacity of lines varies a small amount from hour to hour, but there is greater variation in the capacity declared for the day-ahead market due to the booking of corridor for the clearance of prior markets. If a line can support 3500 MW and 3000 MW is booked prior to the day-ahead market, then transmission capacity for the day-ahead market is the residual 500 MW.

Most short-term contract volume is traded in contracts that last a month or longer. Table A2 shows the total volume of power traded over this three-year period by the duration of the contract. About 7% of trade is on daily contracts and 81% on contracts of at least 28 days. Since monthly contracts are signed in advance of trade this suggests that the contract positions of firms are largely fixed at high frequencies; a day-ahead bidder would not be changing its contract position much hour-by-hour in response to congestion.

Table A2: Volume of Short-Term Contract Trade by Duration

	Volume (GWh)	Volume (%)
Daily	6086	6.8
Weekly	11309	12.7
Monthly or longer	71897	80.5
Total	89292	

The table shows the volume of short-term contracts by the duration of the contract for all contracts executed through power traders, as reported to CERC. Short-term contracts are by definition less than 365 days. Daily contracts are defined as being for 1 day or less, weekly contracts for more than one day but less than 28 days, and monthly contracts for 28 days or longer.

The estimation strategy assumes that contract positions are fixed and estimates marginal costs as the incremental costs to supply power beyond these contract positions. If contract positions were changing at high frequency in response to day-ahead market conditions, such as congestion, this would imply that the estimated marginal costs would be averaged over different parts of the firm-level cost curve.

To investigate whether contract positions respond to short-term market conditions, here we regress hourly contract volumes, in aggregate, on congestion in the day-ahead market. This test is not definitive: demand for electricity will affect both congestion in the day-ahead market and contract positions in the short-term contract market. Because of this endogeneity, or endogeneity on the supply side, there may be a relationship between congestion and short-term contracts even if firms were not signing contracts in anticipation of future day-ahead congestion. However, there is no clear instrument for congestion in this context, so we present the regression as descriptive evidence.

Table A3 reports the results of this regression. The unit of observation is the hour since this is the time block for clearance of the day-ahead market. In column (1) the regression estimate with no controls is that congestion in an hour is associated with contract volume

Table A3: Contract Volume by Day-Ahead Congestion

	(1) Volume (MWh)	(2) Volume (MWh)
Congestion in day-ahead market (=1)	-237.5	-36.9
	(141.0)	(86.0)
Month-of-year controls	No	Yes
Mean volume (MWh)	3578.85	3578.85
Observations	23909	23909

The table reports regressions of hourly contract volume on day-ahead market transmission congestion. The data set consists of all short-term contracts from electricity traders over the period from April, 2009 through March, 2012. Standard errors are clustered at the month level to account for the persistence of contract positions. The symbol * denotes $p < 0.05$, ** $p < 0.01$ and *** $p < 0.001$.

for that hour being lower by 237.5 MWh (standard error 141.0 MWh), which is statistically insignificant, on a mean contract volume of about 3600 MWh. This correlation may be related to seasonal patterns of demand and congestion. In column (2) we add month-of-year dummies as control variables and the coefficient decreases in magnitude to -39.6 MWh (standard error 86.0 MWh). This estimate is small, at about one percent of overall contract volume, and statistically insignificant.

One interpretation of this null result is that, because congestion occurs at high frequency and is not predictable well in advance, contract positions are not very responsive to day-ahead market conditions over the short term. This interpretation is subject to the caveat, mentioned above, that congestion is endogenous to overall electricity market tightness. Over the medium- and longer-term, such as in response to a permanent expansion of the transmission grid, we expect contract positions would change. The implications of these changes for counterfactuals are discussed in Section VII.

B Appendix: Market-clearing and Estimation

B.1 Discretization of Single Bids

The Indian Energy Exchange allows bids to be piecewise-linear functions from price to quantity defined by up to 64 price-quantity pairs. Most bidders use only a small fraction of the available ticks and, moreover, submit bid functions that approximate step correspondences. For example, using the original currency in which bids are submitted, a seller will submit a bid that is equal to zero up to INR 2499/MWh, that discretely steps up over the minimum allowable INR 1/MWh bidding increment to 50 MW at INR 2500/MWh, and remains constant thereafter.

Table B4 summarizes this behavior for sell bids during the study period of November, 2009 through April, 2010. The percentage of bid segments with any slope is 4.18 for fringe bids and 1.54 for strategic bids. Sloping bid segments do supply a greater quantity than flat segments, at 5.14 and 15.73 percent, respectively, but the share of total quantity offered is still low. Because of the limited use of sloping bid segments, single bids are best represented as discrete step functions. For those bids that do have slope, I approximate sloping segments with discrete steps spaced equally within the price range of the bid segment, at up to USD 5/MWh intervals, such that the average quantity supplied over the segment is the same as in the original bid.

Table B4: Prevalence of Sloping Bid Segments in Sell Bids

	Fringe	Strategic
Bid segment has slope	4.18	1.54
Percentage of quantity with slope	5.14	15.73

The limited use of bid slope observed may be because the losses to discrete bidding are small and/or the fixed costs of optimal bidding are large (Kastl, 2012; Hortaçsu and Puller, 2008).

B.2 Treatment of Block Bids

Single bids are hourly functions from price to quantity that are submitted and cleared indepedently for each hour. Block bids specify the maximum willingness-to-pay of a buyer or minimum willingness-to-accept of a seller on average over a continuous block of hours. Each block is specified by a price and quantity p^b, q^b and a set of hours H^b. Blocks allow bidders to reflect cost complementarities in supplying power in contiguous hours, similarly to complex bids (Reguant, 2014). Unlike complex bids, which impose a minimum revenue requirement on the revenues earned by single bids, block bids do not constrain or change the clearance of single bids, other than through their effect on the market-clearing price.

A bidder offering both single and block bids would consider the effect of single bid tick prices on block bid clearance and costs. Let $\hat{p} = \sum_{h \in H^b} p_h / |H^b|$ be the average hourly price over a block and $G(\cdot|H^b)$ be the cumulative distribution function of this price and let δ^b indicate the event that the block is cleared. In terms of equation 1, the bidder's first-order condition for a single bid tick when also bidding with blocks becomes:

$$\begin{aligned}\mathbb{E}_{\sigma_{-it}} \Bigg[\frac{\partial p}{\partial b_{itk}} \Bigg(& q_{it}(p) + \frac{\partial D_{it}^r}{\partial p} p + \\ & \frac{\partial D_{it}^r}{\partial p} \Big(\delta^b C'(q_{it}(p) + q^b) + (1 - \delta^b) C'(q_{it}(p)) \Big) + \\ & \frac{1}{|H^b|} \Big(q^b + G_{\hat{p}}(p^b|H^b) \Big[C(q_{it}(p) + q^b) - C(q_{it}(p)) \Big] \Big) \Bigg) \Bigg] \Bigg|_{p = b_{itk}} = 0,\end{aligned}$$

The first two revenue terms are the same as in the original condition. The second line is a weighted average of marginal costs over whether a block is included or not, as block clearance shifts a firm along its cost curve. The third line is the change in revenue for the block due to the bid tick changing the average price at which the block is cleared and the non-marginal change in costs from the block being included or not.[35]

Block bids, considered through this modified first-order condition, are not empirically important to the single bids of strategic firms. In the above first-order condition, blocks will matter if block inclusion has a large effect on marginal costs, if the single bid price is likely to change the distribution of average prices faced by the block and if the block volume is large. None of these conditions hold empirically. Given that marginal costs are assumed constant in the estimation, block inclusion does not shift marginal costs and the second line of this condition reduces to the product of residual demand slope and constant marginal cost. The average block bid submitted by a strategic bidder applies to a block of $|H^b| = 11$ hours, which via line three makes it unlikely that a single bid tick from a single hour will have a noticeable effect on the distribution of block prices. Strategic bidders, moreover, offer only 9.1 percent

[35] I neglect any feedback of the block clearance onto single bids during other hours of the day.

of their total offered volume through blocks, summing block volume over all the hours to which a block applies, meaning that the effect of block prices on revenue is then also small as $q^b << q_{it}(p)$. For these reasons I assume in the estimation that strategic bidders do not account for the presence of block bids.

Block bids are still a feature of the market environment and so I replicate the block clearing of the exchange in order to match market outcomes. Auctions with blocks are combinatorial, with the clearance of each block depending on the clearance of the others via market prices, so there is not necessarily a unique set of cleared blocks or cleared market-clearing prices over the day (Meeus, Verhaegen and Belmans, 2009). The set of blocks cleared will rather depend on the algorithm for block clearance. The precise algorithm of the exchange is not publicly available. I use a heuristic algorithm that iteratively drops blocks until a set of hourly market-clearing prices is found:

1. Assume all block bids are cleared.
2. Clear the market for each constrained area in all 24 hours of the day.
3. Calculate the difference between the block price p^b and the average hourly price $\hat{p}$ in the hours to which a block applies, $\Delta p = (1 - 2 \cdot \mathbf{1}\{BuyBlock\})(p^b - \hat{p})$.
    - If $\Delta p > 0$ for any cleared block, designate block with the largest Δp as not cleared and return to (1).
    - Otherwise exit.

I do not generally attempt to reinclude blocks that have been dropped at an earlier stage of clearance but may be cleared at the market-clearing prices of later iterations. In step (3) if any block is on the excess side of the market during an hour with an extremal (floor or ceiling) price, that block is given preference to be dropped regardless of whether it has the largest Δp overall. Similarly if at exit the price is extremal in any hour and any blocks on the anti-excess side of the market were not cleared I reinclude such blocks until they are exhausted or the price is no longer extremal.

B.3 Market-splitting Algorithm

The exact algorithm used by the exchange is not published. I recreate the algorithm here and show in the next section that my recreation matches published area-clearing prices very well. The algorithm runs as follows:

1. Clear the market in the constrained area $\mathcal{A}_g(p|\mathbf{L})$, beginning with the whole market.

2. Calculate regional net demands at the market-clearing price within the constrained area.

3. Calculate constraints from regional net demands

    - Calculate difference between regional net demand and import margin or export margin for each region within the constrained area.
    - Calculate difference between implied interregional flows and total path constraints for each combination of regions within the constrained area.

4. Check constraints

    - If any constraint violated:
        - Update the definition of $\mathcal{A}_g(p|\mathbf{L})$ by partioning the grid on binding constraints.
        - Attribute constrained flows into or out of $\mathcal{A}_g(p|\mathbf{L})$ to appropriate regions.
        - If constraint applies within a previously constrained area relax the outer constraint.
        - Return to (1.) for each constrained area separately.
    - Otherwise exit.

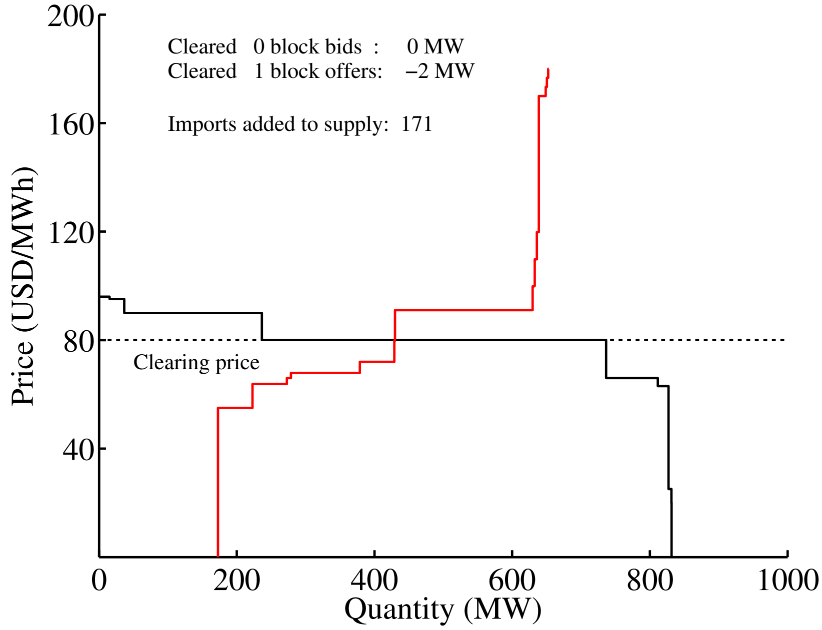
Interregional flows are calculated by minimizing the sum of squared flows subject to meeting the regional net demands (i.e., to Kirchoff's First Law) and respecting binding constraints.

Figure B2 shows the application of the market-splitting algorithm in practice. The unconstrained solution implied a flow to the North region of 571 MW, in excess of its import capacity of 171 MW. The North region was therefore constrained apart from the rest of the grid and these two areas cleared separately, as shown in Figure B2, Panels A and B, with imports added to supply and exports to demand in each area. The importing North region has a clearing price about USD 20/MWh above the other regions and no further constraints bind once these areas are cleared separately. Bidders in each constrained area receive the area-clearing price in that area.[36]

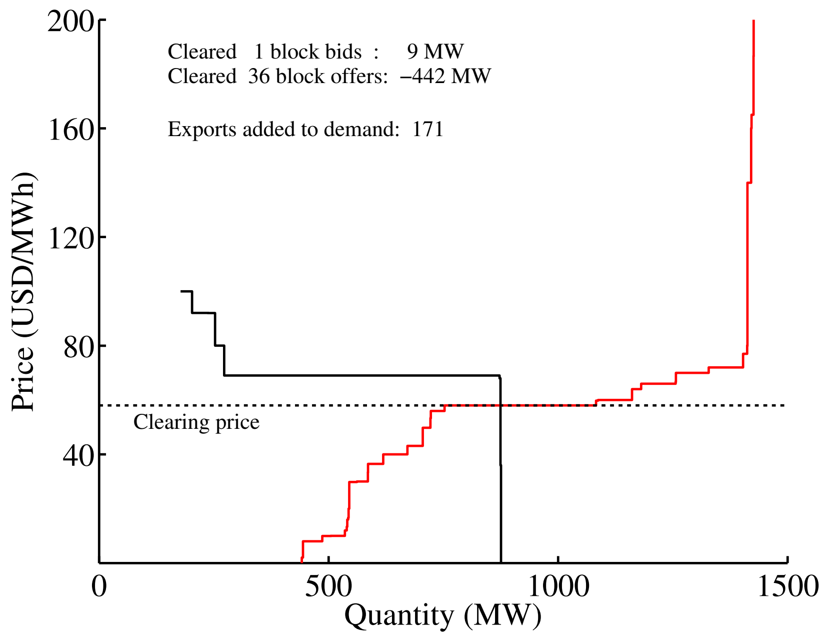
[36]The difference between selling prices in exporting regions and buying prices in importing regions is retained by the system operator, under supervision of the regulator, in a Power System Development Fund. As of March 31, 2011 this fund held USD 91 million (INR 4.57 billion) in congestion revenues.

Figure B2: Constrained Market Clearance
January 26th, 2010, hour 17

A. North region



B. Other regions



The figure shows the constrained market clearance on the Indian Energy Exchange during January 26th, 2010, hour 17. The unconstrained market clearance shown in Figure 2, Panel A implied a flow of 571 MW to North region when only 171 MW of import capacity was available. The market was therefore split into one import constrained area consisting of the North region, shown in Panel A, and one export constrained area consisting of all other regions, shown in Panel B. The imports and exports have been added to the supply and demand curves in each respective panel.

Table B5: Area-Clearing Price Differences

Quarter		Unconstrained Clearance Mean Price	Abs Diff	Pct Diff	Hours	Constrained Clearance Mean Price	Abs Diff	Pct Diff
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
200901	2160	123.99	0.12	0.10	34	120.58	0.06	0.36
200902	2184	155.43	0.30	0.19	776	106.28	0.84	1.44
200903	2208	106.53	0.16	0.15	1192	86.27	1.47	2.40
200904	2208	69.90	0.07	0.10	491	71.53	2.17	3.78
201001	2160	82.16	0.13	0.16	1269	87.36	1.40	2.11
201002	2184	106.02	0.15	0.14	420	119.64	1.01	0.91
201003	2208	61.34	0.08	0.14	174	65.86	0.15	0.23
201004	2208	46.92	0.05	0.11	934	57.22	1.12	1.96
201101	2160	71.29	0.04	0.05	1695	96.98	0.63	0.41

B.4 Accuracy of Market Clearing

The replicated block-clearance and market-splitting algorithms are extremely accurate. I test their accuracy by comparing market prices reported by the IEX to those calculated by clearing the market with the bidding data.

Table B5 reports the results of the market clearance for each quarter from the first quarter of 2009 through the first quarter of 2011. The first four columns show the results for unconstrained clearance in all hours, regardless of whether the hour was constrained or not, as the exchange publishes prices for the unconstrained solution in all hours. The percentage difference betwen exchange prices and calculated prices, all in USD/MWh, is never more than 0.19 percent of the market clearing price in any single quarter and is more often around 0.10 percent. Columns 5 - 8 show the differences between the mean regional price reported and calculated during constraind hours. The errors are somewhat larger, with a maximum of 3.78 percent of the market clearing price across quarters, but still very small on average. The additional error in the constrained relative to the unconstrained price does not necessarily imply error in the market-splitting algorithm. Rather, on inspection, most of the hours when the two prices differ appear to be an interaction of transmission constraints with small changes in block clearance, which affect clearing prices more in relatively illiquid, constrained regions than in the market as a whole.

B.5 Day-ahead bidding with forward contract position

This section slightly extends the firm's problem from Section IV by including forward physical contract positions. Exogenous physical contract positions only affect the firm's problem by moving the firm along its cost curve.

The firm's problem is:

$$max_{\mathbf{b_{it}},\mathbf{q_{it}}} \mathbb{E}_{\sigma_{-it}} \left[q_{it}^{DA}(p^{DA})p^{DA} + q_{it}^{C} p_{it}^{C} - \tilde{C}_i(q_{it}^{DA}(p) + q_{it}^{C}) \right].$$

Where $q_{it}^{DA}(p^{DA})$ is the supply function in the day-ahead market, which depends on the price b_{itk}^{DA} and incremental quantity q_{itk}^{DA} of each bid tick k and $\tilde{C}_i(\cdot)$ is i's total cost of production. The contract quantity q_{it}^{C} and price p_{it}^{C} are taken as exogenous.

We consider a grid without congestion to simplify notation. Taking the derivative with respect to each bid-tick price, a necessary first-order condition for profit maximization is

$$\mathbb{E}_{\sigma_{-it}} \left[\frac{\partial p^{DA}}{\partial b_{itk}} \left(q_{it}^{DA}(p^{DA}) + \frac{\partial D_{it}^{rg}(p^{DA}|\sigma_{-it})}{\partial p^{DA}} (p^{DA} - \tilde{C}_i'(q_{it}^{DA}(p) + q_{it}^{C})) \right) \right] \Bigg|_{p^{DA}=b_{itk}} = 0.$$

The contract price and quantity are irrelevant for the revenue part of this condition since the contracting decision is sunk. The contract quantity affects bidding through the cost function since firms that have contracted now have to produce with higher-cost units, further out on the marginal cost curve. If we define $C_i'(q_{it}^{DA}(p)) = C_i'(q_{it}^{DA}(p)|q_{it}^{C}) \equiv \tilde{C}_i'(q_{it}^{DA}(p) + q_{it}^{C})$, then the first-order condition here is the same as in the text. Thus from ignoring physical contract positions the only affect on bidding, and hence estimation, is that marginal costs must be interpreted as incremental costs beyond firms' (unobserved) forward contract positions.

B.6 Accuracy of Bootstrap Replications

The estimation depends on accurately replicating the uncertainty faced by sellers over market-clearing prices and residual demand. This section briefly reports comparisons between the distribution of actual prices and the distribution of prices under the bootstrap replications of market outcomes for the single largest seller.

Table B6 shows moments of the actual and simulated price distribution for the Unconstrained, North and West prices, respectively. The means and standard deviations of the

Table B6: Accuracy of Prices Simulated by Bootstrap (USD/MWh)

	Unconstrained		North		West	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
Mean	87.06	87.39	86.85	85.91	80.72	79.30
Std	48.52	48.44	48.52	48.36	48.06	48.27
Skewness	0.99	0.97	0.97	0.99	1.30	1.29
Kurtosis	3.90	3.95	3.86	4.04	4.54	4.68
Min	1.99	0.00	1.99	0.00	1.99	0.00
p10	30.03	30.04	30.03	30.02	30.02	30.00
p25	52.01	52.02	50.01	50.02	49.99	49.60
p50	79.99	80.00	80.01	80.00	68.01	65.80
p75	110.03	115.02	110.01	110.04	99.99	100.00
p90	160.01	159.00	160.02	159.96	160.01	156.02
Max	278.01	295.36	278.01	360.02	278.01	400.00

actual and simulated prices are very similar for each distribution. The simulated prices have slightly fatter tails, with floor prices observed in practice, unlike in the actual prices, and somewhat higher maximum prices. The bootstrap of bids at the daily level does not guarantee there will be demand bids in any given hour, hence generating the floor prices. The other, interior quantiles of the distribution match very closely. The right tails of the Unconstrained distribution, which reflects demand in the South region and the North region, and in the North region, are above the right tails in the West region from the median through the 75th percentile. Comparisons for the uncertainty faced by other sellers and in individual hours of the day also show similar distributions of actual and simulated clearing prices.

B.7 Smoothing of Residual Demand

Both the estimation and counterfactual simulations model the residual demand as a smooth curve, rather than a step function. I approximate residual demand and its derivative with kernel-smoothed functions. Let j index bids from both the demand and supply sides, where q_{jk} is the incremental increase in supply or decrease in demand from firm j above price p_{jk}. Let $D^g(0, \sigma_{-it})$ be the total demand in the area of region g at a price of zero and $\mathcal{A}_g$ be short for $\mathcal{A}_g(p|\mathbf{L})$. Then residual demand and its derivative are approximated using a normal kernel as:

$$\tilde{D}^{rg}_{it}(p|\sigma_{-i}, \mathcal{L}_t) = -\sum_{j\neq i, j\in\mathcal{A}_g}\sum_k q_{jk}\Phi\left(\frac{p-p_{jk}}{w}\right)$$
$$\frac{\partial\tilde{D}^{rg}_{it}(p|\sigma^{\mathbf{s}}{}_{-i}, \mathcal{L}_t)}{\partial p} = -\frac{1}{w}\sum_{j\neq i, j\in\mathcal{A}_g}\sum_k q_{jk}\phi\left(\frac{p-p_{jk}}{w}\right).$$

The bandwidth w controls the degree of smoothing, with a larger bandwidth smoothing the curve more. I set w = USD 10/MWh in the estimation, which is 11 percent of the mean unconstrained market-clearing price and 0.21 standard deviations in this price. Own-supply is smoothed in a similar manner. The derivatives of residual demand and own-supply then form the weights of the first-order condition as $\frac{\partial p}{\partial b_{itk}} = \frac{\partial q_{it}(p)}{\partial b_{itk}} / \left(\frac{\partial D^{rg}_{it}(p)}{\partial p} - \frac{\partial q_{it}(p)}{\partial p}\right)$, by the implicit function theorem.

Table B7: Robustness of Estimated Marginal Costs (USD/MWh)

	IV = No, w = 10		IV = No, w = 15		IV = Yes, w = 10	
Wtd. Mean Tick Price	Estimated Marginal Cost	Std. Err.	Estimated Marginal Cost	Std. Err.	Estimated Marginal Cost	Std. Err.
(1)	(2)	(3)	(4)	(5)	(6)	(7)
93.35	75.66	(7.44)	76.36	(5.81)	84.42	(6.93)
60.41	47.18	(1.79)	48.94	(1.94)	57.47	(2.80)
73.39	56.85	(3.20)	57.59	(2.99)	68.91	(4.49)
87.54	82.64	(6.21)	83.27	(7.60)	100.01	(7.61)
73.20	61.68	(1.37)	60.92	(1.58)	64.32	(1.55)
48.46	36.66	(1.09)	36.59	(1.00)	39.98	(1.14)
91.32	80.71	(2.22)	80.22	(2.11)	80.90	(2.02)
35.98	19.17	(1.07)	19.24	(1.08)	20.58	(1.32)
66.86	58.56	(0.79)	58.28	(0.94)	59.68	(1.01)
109.98	62.30	(2.84)	67.32	(2.91)	65.64	(3.43)
132.39	118.86	(3.95)	119.17	(3.56)	121.05	(3.94)
36.57	45.33	(0.52)	44.46	(0.53)	45.06	(0.76)
14.90	14.08	(1.97)	10.53	(1.24)	14.32	(2.12)
			Column Means			
71.10	58.44		58.68		63.25	

The table shows robustness checks for the cost estimates of Table 5. The rows represent strategic sellers ordered as in that table. Strategic sellers are those sellers in the North and West region with at least one percent market share as determined by the share of offered volume. Columns 2 and 3 give the coefficients and standard errors for the estimates without instrumental variables and with a bandwidth of USD 10/MWh for smoothing residual demand. Columns 4 and 5 give estimates using a larger bandwidth of USD 15/MWh. Columns 6 and 7 give the Table 5 estimates at the original bandwidth and using lagged temperature as an instrument for the moment conditions, on the assumption that lagged temperature shifts expected demand but does not affect supply shocks. Standard errors are bootstrapped by resampling 100 bootstrap iterations with replacement from the set of moment conditions.

In Table B7 I test the robustness of the cost estimates to different smoothing parameters and to not instrumenting the moment conditions with lagged temperature.

The main IV estimates of marginal cost are in column 6 and column 2 reports estimates without instruments. The mean marginal cost estimates across all bidders is a modest 8 percent higher in the main IV estimates, reducing bidder margins, and the mean absolute deviation between the baseline and IV estimates is also 8 percent. Endogeneity of bids driven by cost shocks appears a mild concern in this market, perhaps because few supply shocks are realized by the time offers are made, a day ahead of delivery.

In column (4) I present estimates of marginal cost without IV using a smoothing parameter 50 percent larger than in the baseline case (i.e., $w =$ USD 15/MWh instead of USD 10/MWh). Because the smoothing parameter partly determines the elasticity of residual demand, it changes the moment conditions, and one may be concerned that this parameter arbitrarily influences the estimates of marginal cost. The estimates are practically unchanged, with the mean cost estimate higher by 0.42 percent and the mean absolute deviation over all cost estimates only 3.42 percent, relative to column (2). The estimated costs thus do not appear very sensitive to a marginal change in the degree of smoothing.

C Appendix: Counterfactual model equilibrium and robustness

C.1 Cournot model equilibrium conditions and solution method

Consider a set of strategic firms i with marginal costs γ_i facing a residual demand curve $D^g(p|\sigma_{-it}, \mathcal{L}_t)$ with a twice-continuously differentiable inverse residual demand curve $\tilde{P}^g(Q^g|\sigma_{-it}, \mathcal{L}_t)$, where Q^g is aggregate strategic quantity offered in region g by all strategic firms together. For now, take the division of the market into regions g as exogenously given; I will discuss how the regions are determined below.

The derivative of profit with respect to the seller's offered quantity q_{it} is:

$$f_{it}(q_{it}) = \tilde{P}^g(Q^g|\sigma_{-it}, \mathcal{L}_t) + q_{it}\tilde{P}^{g\prime}(Q^g|\sigma_{-it}, \mathcal{L}_t)) - \gamma_i. \tag{3}$$

Necessary and sufficient conditions for an equilibrium set of quantities are that for all strategic sellers i:

$$\begin{aligned} q_{it} \in (0, \overline{q}_i) \quad &\perp \quad f_{it}(q_{it}) \neq 0 \\ q_{it} = 0 \quad &\perp \quad f_{it}(q_{it}) \geq 0 \\ q_{it} = \overline{q}_i \quad &\perp \quad f_{it}(q_{it}) \leq 0. \end{aligned}$$

Here $\overline{q}_i$ is the maximum quantity that a strategic seller can offer, due to capacity constraints. The form of this problem is a mixed-integer complementary problem, since the equilibrium conditions are complementarity conditions between capacity constraints binding and the firm's first-order condition for an interior quantity. If the seller produces an interior quantity, between zero and their constraint, then it must be that the derivative of profits with respect to quantity at that point is zero. Similarly, if the seller produces nothing this derivative must be negative, else they would increase quantity, and if the seller produces at their quantity constraint this derivative must be positive, else they would decrease quantity.

The conditions for profit maximization depend on the first and second derivatives of inverse residual demand with respect to quantity. I represent inverse residual demand function $\tilde{P}^g$ as a set of whole quantities and incremental prices and smooth over quantities, with the same kernel-smoothing method described in , in order to approximate the derivative of inverse residual demand. When smoothing over quantity I use a bandwidth w_q equal to ten percent of the range of quantities spanned by the residual demand curve.

The problem is linear in q_{it} if one neglects the effect of each seller's quantity on the aggregate Q^g. Similarly to Bushnell, Mansur and Saravia (2008), I solve this problem with the sequential linear complementarity problem approach of Kolstad and Mathiesen (1991) using the PATH algorithm on each iteration (Dirkse and Ferris, 1995). This algorithm solves a linear complementarity problem for a vector of q_{it} on each iteration and then sequentially updates Q^g to formulate another linear problem, repeating the process until convergence. Sufficient conditions for the uniqueness of Cournot equilibria generally require pseudoconcavity of profit functions (Kolstad and Mathiesen, 1987). Given constant marginal costs, the profit functions must inherit this property from the demand function.

The regions g into which the grid is divided are determined by nesting the Cournot problem within the market-splitting algorithm, described in Appendix B B.3, which deals with constraints in practice. The treatment of congestion in the counterfactuals is therefore the same as in estimation. That is, the Cournot model is first solved on the unconstrained grid, and the equilibrium prices, quantities and inter-regional flows are calculated. If these flows and the implied regional imports and exports violate any transmission constraints, then those constraints are assumed binding, and a new Cournot equilibrium is solved on the constrained grid divided by these constraints. Iterations continue until an equilibrium is found and no additional constraints bind, as described in the market-splitting algorithm.

The implication of this algorithm for the model is that strategic sellers behave with certainty that the grid constraints will bind as they do in equilibrium, and that strategic sellers account for the effects of inelastic equilibrium imports and exports in their bids. The first-order conditions of strategic sellers are confined to their constrained regions, and will be altered by both the slope and the level effects described in Section II III.C.. Strategic sellers do not, however, 'see through' the iterations of the market-splitting constraint to account for the endogeneity of the constraints with respect to their bids. This assumption strongly simplifies the problem and is realistic given the relative non-concentration of the unconstrained grid.

C.2 Uniqueness of equilibrium

The Cournot model used does not theoretically guarantee a unique equilibrium here, for two reasons. The first reason the equilibrium may not be unique is the presence of transmission constraints. Transmission constraints can produce multiple equilibria, with lines congested in different directions, or leave no pure-strategy equilibria at all. In markets with asymmetric firms and demand across regions, a pure-strategy equilibrium of the Cournot model will virtually always exist: the condition necessary for two regions is only that the two regions have different monopoly prices (Borenstein, Bushnell and Stoft, 2000). The asymmetry in the Indian day-ahead market between a relatively low-priced central core, of the West and North region, and a high-priced periphery, of the North and South, suggests there will be a single pure-strategy equilibrium, as it will not be worthwhile, or even possible, for the suppliers in power-scarce regions to congest the line outwards in order to gain market share from relatively abundant regions.

The second reason that the equilibrium may not be unique is that the residual demand curve here is not always pseudoconcave. Because I smooth inverse residual demand but do not otherwise restrict its shape, it can alternate between concave and convex regions at different quantities, which may, but will not necessarily, admit multiple equilibria at different clearing volumes.

Empirically, I search for multiple equilibria, by starting the equilibrium search at different quantities, but generally find a unique equilibrium for every hour. In the baseline simulation I initialize the search for an equilibrium at the point where all strategic sellers have equal quantities and supply 75 percent of the maximum residual demand. This could in principle lead to selection of local equilibria further out on the demand curve than the actual equilibria selected by firms, in accord with the discussion of Section IV IV.B.. I test for the importance of equilibrium selection by instead allocating strategic sellers 25 percent of the maximum residual demand to start. This produces an average unconstrained market price of USD 73.78/MWh over the sample period, indistinguishable from the price of USD 73.74/MWh in the baseline simulation, indicating that a different equilibrium has been found in at most a handful of hours. The two simulations also match exactly on other dimensions of congestion and market volume.

Therefore, though I cannot rule out multiple equilibria, multiplicity does not appear to be important in practice. I speculate that this is due to the typical shape of the demand curve. In many hours, the demand curve is inelastic at low and high prices and elastic at moderate prices, as in Figure B2, Panel B.[37] In principle, this can create distinct concave portions of residual demand where equilibria might be found. In practice, though, the potential equilibrium higher up the residual demand curve are at very low or even negative quantities, and sellers can increase profits in this part of the curve by selling more, even if it brings prices down.

C.3 Model fit

Table C8, Panel A, compares unconstrained market clearance with the bids actually submitted, in columns 1 and 2, with outcomes for the unconstrained Cournot model, in columns 3 and 4. I present the unconstrained clearance of the submitted bids for reference, but consider it an inappropriate benchmark for whether the model matches market conduct, because

[37] The extreme elasticity at moderate prices comes mainly from industrial consumers that have outside options of purchasing from unscheduled interchange or from state suppliers at prices in this range.

it runs unconstrained clearance using bids that were offered in a constrained environment. The model overpredicts unconstrained quantity, shown in Panel A, and therefore underpredicts unconstrained price by 13 percent (USD 11.5/MWh on a base of USD 87.1/MWh). In reality, when firms bid, they know that they will face regional demand and be paid based on constrained, regional prices. This implies that an 'unconstrained' market, calculated by turning off transmission constraints but not changing bids, should have lower quantities than predicted by the model, as is observed.

Table C8, Panels B through D show that the model matches constrained market outcomes—that is, true market outcomes—extremely well, especially considering the parsimonious specification of costs. The North region is import constrained with respect to the West region 17 percent of hours in the model, as against 18 percent of hours in reality. The price difference between these regions conditional on the North price being greater is USD 28.2/MWh in the model and USD 33.7/MWh in the actual market clearance. The North region and West region have similar average net demands in the model as in the actual clearance, and these net demands are similarly variable. The fit in the South 1 region is also very good; for example, the difference between South 1 and West prices conditional on congestion is USD 32.9/MWh in fact and USD 39.5/MWh in the model.

C.4 Robustness of counterfactuals

The counterfactual estimates in the paper use the maximum monthly volume offered as a measure of firm capacity in that month. It is possible that capacity is greater than the monthly maximum offered, for example if firms are strategically withholding during periods of high congestion. Table C9 compares the counterfactual gains in surplus under the baseline capacity constraints (Panel A) to those under looser capacity constraints (Panel B), taken as the maximum volume offered across the whole sample. The change in surplus from transmission expansion to the North region does not depend on capacity constraints (USD 3.8 thousand per hour under monthly constraints and USD 3.5 thousand per hour under sample constraints). The change in surplus from a transmission expansion to the South region is somewhat higher under the looser capacity constraints. For example, the change in surplus due to a 1200 MW transmission expansion into the South region is USD 6.59 per hour under the monthly constraints and USD 8.24 per hour under the sample-wide constraints.

Table C8: Model Fit

	Actual		Model	
	Mean	Std Dev	Mean	Std Dev
	(1)	(2)	(3)	(4)
Panel A. Unconstrained				
Clearing price (USD/MWh)	87.06	48.52	75.52	34.20
Clearing quantity (MW)	936.82	328.64	1225.49	505.98
Panel B. Constrained, North region				
Clearing price (USD/MWh)	86.85	48.52	77.80	35.30
Price > West price (% of hrs)	0.18	0.39	0.17	0.37
Price − West Price (if not equal)	33.71	21.84	28.18	19.24
Net demand (MW)	258.45	244.49	348.25	261.10
Panel C. Constrained, South 1 region				
Clearing price (USD/MWh)	88.39	51.20	85.60	45.05
Price > West price (% of hrs)	0.23	0.42	0.32	0.47
Price − West Price (if not equal)	32.94	24.58	39.54	25.18
Net demand (MW)	-81.10	180.84	-81.55	186.13
Panel D. Constrained, West region				
Price (USD/MWh)	80.72	48.06	75.20	37.12
Net demand (MW)	-346.12	247.01	-459.53	299.67

The table shows the fit of the Cournot model to market outcomes on the day-ahead market from November, 2009 through April, 2010. In each panel the first two columns show the mean and standard deviation of each outcome for the actual market clearance, using the bids submitted to the exchange. Columns 3 and 4 show market outcomes under the Cournot model equilibrium. The Panels represent different treatments of transmission constraints. In Panel A the clearance is conducted and the model is solved assuming no transmission constraints exist. Note that the unconstrained clearance benchmark of Panel A, columns 1 and 2, commonly used by the exchange, is itself a naïve counterfactual, conducted using bids submitted under constrained conditions. In Panels B through D, market outcomes from constrained clearance are shown using bids as submitted and as predicted by the model.

Table C9: Counterfactual Market Outcomes with Expanded Transmission Capacity

		North		South	
Transmission expansion	None	400 MW	1200 MW	400 MW	1200 MW
	(1)	(2)	(3)	(4)	(5)
Panel A. Cournot, monthly capacity constraint					
Price					
North > West (% of hrs)	0.17	0.08	0.01	0.17	0.18
North − West (USD/MWh)	29.92	25.85	28.86	29.21	29.19
South 1 > West (% of hrs)	0.31	0.30	0.30	0.09	0.01
South 1 - West (USD/MWh)	38.91	38.57	38.58	29.07	20.43
Quantity (MW)					
North net demand	325.80	386.81	421.46	278.61	250.54
South 1 net demand	-82.43	-85.83	-86.55	-31.89	12.16
West net demand	-431.24	-478.93	-507.68	-471.67	-489.43
Strategic seller cleared	603.73	619.43	630.27	665.81	699.56
Surplus (USD '000s)					
Market	58.49	60.73	62.29	62.82	65.08
Buyer's	19.70	20.67	22.48	22.22	24.07
Seller's	38.79	40.05	39.81	40.60	41.00
Panel B. Cournot, sample capacity constraint					
Price					
North > West (% of hrs)	0.17	0.08	0.01	0.18	0.19
North − West (USD/MWh)	28.18	24.97	25.84	27.62	27.61
South 1 > West (% of hrs)	0.32	0.31	0.30	0.09	0.00
South 1 - West (USD/MWh)	39.54	39.72	39.82	30.42	20.59
Quantity (MW)					
North net demand	348.25	412.38	446.49	305.34	277.04
South 1 net demand	-81.55	-84.62	-85.24	-28.29	17.97
West net demand	-459.53	-510.55	-539.73	-508.53	-527.30
Strategic seller cleared	644.98	653.81	661.99	714.45	749.67
Surplus (USD '000s)					
Market	61.94	63.92	65.43	67.07	70.18
Buyer's	21.33	22.12	24.16	24.38	26.48
Seller's	40.61	41.81	41.27	42.68	43.71

The table shows counterfactual market outcomes under different assumptions on transmission capacity, across panels, and market conduct, across columns. Column 1 represents competitive market clearance with no transmission expansion. Column 2 represents competitive conduct with transmission expansions as shown in each panel. Column 3 represents Cournot market clearance with no transmission expansion. Column 4 is Cournot conduct with fixed bids, where the quantities offered by strategic sellers in equilibrium are found at the baseline level of transmission, then held fixed as transmission expands. Column 5 represents Cournot conduct with endogenous bids that respond to transmission expansions as shown in each panel. Within each panel, market prices, quantities and surplus are shown, for the regions or parties indicated in the row headings.