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

Nicholas Ryan

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Abstract

Public infrastructure can improve welfare both by directly lowering the costs of trade and by fostering competition. I study the competitive effects of transmission infrastructure on market outcomes in the Indian day-ahead electricity market. Transmission constraints may increase local market power by limiting competition across regions. Bidders in import-constrained regions are estimated to raise bid prices by 17 percent of the market-clearing price in response to congestion due to exogenous within-day changes in transmission capacity. I estimate firm marginal costs from bids accounting for transmission constraints and run counterfactual simulations to measure the effect of increasing transmission capacity with endogenous bidder response. I find that relaxing import constraints into the two most constrained regions would increase total surplus by 19 percent of baseline market surplus. Comparing the results of this expansion with counterfactuals holding strategic bids fixed at baseline levels, the strategic response to transmission expansions accounts for 72 percent of this welfare gain.

JEL Codes: 025, L11, L13, L94

1 Introduction

Public infrastructure can improve welfare both by directly lowering the costs of trade and by fostering greater competition. In India, for example, railroads have been found to lower internal trade costs, whereas mobile phone towers improved efficiency by unifying local markets (Donaldson, 2010; Jensen, 2007). The right level of public investment will depend on the competitive effects of infrastructure. Such effects appear especially important in the deregulation of electricity markets: legacy transmission networks, built with the idea that production

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would be regulated, have often been inadequate to ensure competition amongst generating firms (Borenstein et al., 2000; Joskow, 2008).

India has been in a more or less acute state of policy-induced energy crisis for decades. It has the greatest aggregate level of energy subsidies to fossil fuels and electricity of any country in the world and the fifth-largest, at 3.4%, as a share of GDP (Organisation for Economic Cooperation and Development, 2011). These subsidies have helped create large shortages of electricity. Electricity supply is on average 10 percent short of demand (Central Electricity Authority, 2011). Wolak (2008) wrote that it was "difficult to imagine more adverse initial conditions" for any electricity restructuring than were present in India. The Electricity Act of 2003 was a constrained effort to reform the power sector and in particular to induce greater private investment by allowing open access to the electricity grid and wholesale power trade (Thakur et al., 2005). The transmission grid, once opened, has been inadequate to support a competitive national market. On the day-ahead electricity market, an important platform for trade, the load centers of the North and South are import constrained 18 and 26 percent of the time, respectively, during my study period, and these constraints create large differences in the price of power across regions. These price differences reflect demand and cost conditions across regions, but suppliers may also have the opportunity to raise prices in the small, regional markets broken off by transmission constraints.

This paper studies the competitive effects of inadequate transmission infrastructure in the Indian day-ahead electricity market and estimates the welfare gains from increased investment in this sector. I use confidential data on bids, offers and transmission constraints on the leading power exchange to estimate bidder response to congestion and the welfare gains of relaxing transmission constraints. The empirical approach has two distinct parts. I first estimate the bidder response to congestion in reduced-form by regressing prices bid on congestion, instrumenting congestion with regulatory decisions about transmission capacity allocation within the course of a given day. I find that bidders raise prices by INR 742/MWh, or 17% of the average unconstrained market clearing price, in response to congestion.

In order to estimate the overall competitive and welfare effects of congestion, the second part of the empirical approach uses a structural model of the day-ahead market with transmission constraints. I construct first-order conditions for profit-maximizing bids based on the residual demand curves faced by each seller under transmission constraints and use these conditions to estimate marginal costs. I then restrict strategic sellers to Cournot strategies and estimate market outcomes under counterfactual levels of transmission constraints with both strategic bids fixed at their baseline level and endogenous bids that respond to the increased transmission capacity.

There are two primary findings from the structural model. First, market structure and transmission constraints, not high costs, produce high prices. Despite generally high market prices, the model rationalizes the observed pattern of bidding with reasonable estimates of the marginal cost of supply, comparable to published cost estimates for the industry. Second, the welfare gains from transmission expansion are large and mostly due to the competitive effects of additional transmission capacity. Counterfactual 1200 MW increases in import capacity to the North and South regions produce estimated welfare gains of INR 1.39 billion (USD 27.80 million) and INR 4.08 billion (USD 81.67 million) per annum, respectively, which together are 19% of the total baseline market surplus. By comparison with counterfactuals that hold strategic bids fixed at baseline levels, I calculate that 72% of this welfare gain is due to transmission expansion removing opportunities for the exercise of market power.

This paper fits in two places, with the literature on how market structure leads to outcomes in restructured electricity markets and with the development literature on the welfare effects of infrastructure. The electricity literature focuses specifically on how market institutions affect the ability of generating firms to exercise market power, i.e. to raise prices above cost. Past studies of market power often use observed cost data to simulate market prices and quantities.[1] This paper follows a parallel stream of literature that instead backs out marginal cost from observed bidding behavior and estimates or models the impact of changes in market structure (Wolak, 2003, 2007; Gans and Wolak, 2008; Reguant, 2011).

Transmission constraints are widely acknowledged as vital to the competitiveness of electricity markets but have been little studied empirically. Borenstein et al. (2000) study the effects of transmission capacity in a Cournot model thoroughly and find that small changes in line capacity can have very large competitive effects. The empirical literature on congestion in operations research has focused on feasible, robust solution concepts for complex transmission networks (Hobbs et al., 2000). The closest antecedents to the model in this paper are Wolak

[1] Borenstein et al. (2000) find that market power in California's restructured wholesale electricity market resulted for 59% of the nearly $7 billion rise in expenditures between 1999 and 2000. Bushnell et al. (2008) show convincingly that vertical arrangements are an important reason why these high prices do not generally obtain in U.S. markets.

(2003) and Reguant (2011) with respect to the estimation approach and Neuhoff et al. (2005) and Xu and Baldick (2007) with respect to the counterfactual treatment of congestion. A range of empirical electricity papers have noted the importance of congestion in the markets under study (Hortacsu and Puller, 2008; Reguant, 2011; Allcott, 2012).

With respect to infrastructure more broadly, there is a growing development literature on the market and welfare effects of many types of investment. Dinkelman (2011) finds that access to electricity through an expanded distribution network increases the market labor supply of women. Donaldson (2010) estimates increases in income due to railroads lowering the cost of internal trade in India. Banerjee et al. (2012) find that access to transportation networks between the major cities in China increases local output, though not growth. Faber (2012) finds Chinese highways reduce growth in rural areas by shifting production to larger cities.

The paper contributes in both of these areas. In the electricity literature, I extend the use of the necessary conditions for optimal auction bidding to incorporate transmission constraints. Complete knowledge of the relevant constraints and a simple but non-trivial network structure allow me to model exactly how congestion enters optimal bids and how congestion would change with different bids. This is also one of the first, if not the first, micro-econometric study of a power market in a developing country.[2] On the effects of infrastructure, I focus on the competitive effects of investment rather than the direct effects of a fall in transport costs. These competitive effects may be important in many settings when infrastructure integrates previously isolated markets. Knowledge of the industry cost and demand structure enable me to calculate unusually comprehensive estimates of the welfare gains from investment and the share of these gains due to increased competition.

The rest of the paper runs as follows. Section 2 discusses the day-ahead market in the context of the Indian power sector. It describes the nature of transmission congestion in the market and estimates the bidder response to congestion on one corridor in reduced-form. Section 3 introduces a model of supplier bidding and describes the approach to estimation and counterfactual simulations. Section 5 presents estimated firm costs and the results of counterfactual transmission expansions. Section 6 concludes.

[2]Bacon and Besant-Jones (2001) describes the experimentation of developing and transition countries with different stages of electricity liberalization. Williams and Ghanadan (2006) and Jamasb (2005) survey the experience of such countries with reform. A number of studies, such as Zhang et al. (2008), estimate cross-country regressions to evaluate reform in a structure-conduct-performance paradigm.

2 Institutions

The Indian electricity sector is characterized by persistent imbalances. Peak demand exceeded supply by 18% in 1996, 13% in 2002 and 13% in 2011 (Thakur et al., 2005; Central Electricity Authority, 2011). A combination of artificially low agricultural and retail tariffs and poor incentives for investment in generation have sustained this gap and made electricity supply an extremely unprofitable business (Wolak, 2008). The Electricity Act of 2003 was a major reform intended to correct some of the structural problems with the electricity supply sector in India and to create a larger role for market forces. This reform touched on nearly every aspect of electricity generation, transmission and distribution but was particularly meant to foster competition and induce private capacity addition by opening access to the power grid (Thakur et al., 2005). The Central Electricity Regulatory Commission sets the terms for grid access and regulates power trade on all platforms.

Part of this Act sanctioned wholesale markets for power and two private exchanges opened in 2008 to provide a platform for the trade of power one day-ahead of delivery. These exchanges serve as intermediaries not only for traditional state generating companies and distribution companies but also for an increasingly active private sector on both the supply and demand sides. The next section places the day-ahead market, the focus of this paper, in context.

(a) Role of the Day-ahead Market in the Indian Electricity Sector

There are three ways to trade electricity in India: bilateral contracts, the day-ahead market and unscheduled interchange. These forms of trade differ in their horizon relative to the date of delivery as well as in the nature of price discovery and delivery commitments. The day-ahead market has a small share of generation but is important as a competitive canary in the coal mine of the Indian power sector. In particular, as the only platform to directly price the scarcity due to congestion, the day-ahead market is the best channel through which to study the role of congestion in the Indian market.

The day-ahead market is a double-sided auction conducted each day for 24 hourly blocks the following day on two power exchanges, the Indian Energy Exchange (IEX) and Power Exchange India Limited (PXI). The two exchanges together have a market share of about

2% of generation (Central Electricity Regulatory Commission, 2011). [3] [4] As IEX has over 90% market share I study bidding on this exchange alone throughout the paper. 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. Figure 2, Panel A shows an example of the unconstrained market clearance in a single hour, January 26th, 2010, hour 17 (16:00-17:00). The clearing price is the least price at which supply and demand intersect and the clearing volume the lesser of the supply and demand volume at the clearing price.[5] The supply and demand curves have been shifted out by the volume of cleared block bids.[6] Blocks are a relatively small part of the Indian market and, while incorporating blocks in the market clearance throughout, I will take them as exogenous in the counterfactual simulations.

The day-ahead market is preceded by a contract market and followed by a real-time balancing mechanism with administered prices. Bilateral contracts may be long-term (greater than one year) or short-term. In fiscal 2010, 90% of electricity generation was traded on long-term physical contracts, typically between state-owned generators and distribution companies (Central Electricity Regulatory Commission, 2011). Contracts of shorter duration comprise a further 5% of generation and are more likely to be between private generation companies (called independent power producers or IPPs). Real-time balancing in the Indian market is done through an administrative mechanism called unscheduled interchange (UI). The prices for balancing 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

[3]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 market, which serves 51 million people (Central Electricity Authority, 2011; Central Electricty Authority, 2012; International Energy Agency, 2011)

[4]Note that this figure is not directly comparable to the market shares of power exchanges in other liberalized markets as India has no forward financial contracting for electricity, only physical contracting. In the PJM (United States), NEM1 (Australia) and Spanish markets, 90%, 88% and 91% of physical output has already been covered by financial contracts and so is not exposed to the spot market price (Allcott, 2012; Wolak, 2007; Reguant, 2011). Therefore the nascent Indian short-term market is not so far from international norms in terms of the *net* volume of power traded.

[5]As discussed in the Appendix, the Indian Energy Exchange actually uses piecewise-linear bids that are strict functions from price to quantity. Bidders in practice use these functions almost exclusively to closely approximate step functions (strictly correspondences) with constant quantities for a range of prices and then discrete increases in quantity over the minimum allowed price tick. I assume bids to be of a true step form throughout and do not use the linear interpolation of the exchange, which makes a trivial difference in clearing prices.

[6]Block bids are cleared by an iterative algorithm described in the Appendix.

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.

Bidders arbitrage between the contract, day-ahead and UI markets, though these markets do not offer perfect substitutes. Power on the three platforms is procured at different horizons and has different accompanying delivery risks. The prices of electricity transacted on the power exchanges in fiscal 2010 averaged INR 3470/MWh, lower than the prices through contracts (INR 4790/MWh) or UI (INR 3910/MWh). These differences may reflect the lower risk of congestion for contracted power relative to the power exchanges and the convenience of UI in responding to short-term demand shocks. There are also institutional limits to arbitrage between the day-ahead market and unscheduled interchange designed to prevent sellers from withholding power from the schedule and supplying it through UI. The UI charges paid to sellers are capped and the maximum allowable deviation from schedule also capped when UI prices are high (Central Electiricty Regulatory Commission, 2009) The UI regulation also explicitly threatens sellers that persistently deviate from schedule with regulatory action. Arbitrage at high frequency is further muted by many states apparently settling UI charges over a monthly or quarterly horizon, rather than at hourly prices.[7]

The overall picture of short-term power trade is then of closely but not perfectly integrated markets where arbitrage is easier for buyers than for sellers. In particular, and most relevant for this study, the cost of the marginal unit of supply for large sellers at high frequency is not dictated by the administrative prices for real-time balancing. Thus the bids on the day-ahead market and estimated supplier costs will reflect private physical and opportunity costs of offering power in the day-ahead market and not the common opportunity cost of not supplying in real time.

(b) Structure of Power Grid and Congestion Management

Bidding in the day-ahead market occurs in six functionally distinct regions and I study congestion between these regions. The simple but not trivial structure of the grid makes the day-ahead market well-suited to the study of congestion. As shown in Figure 1, Panel A, the power exchange designates bids as coming from one of ten subregions, two each for the

[7]Personal communication, S. C. Saxena, National Load Dispatch Centre. This observation is supported by the fact that the correlation of UI and day-ahead prices is higher at the monthly average (0.83) than hourly (0.56) level.

Northeast, East, North, South and West regions of the country. The only constraint within a region to bind in the history of the power exchanges has been between the South 1 and South 2 subregions. I therefore consider these two subregions as functionally distinct along with the other four main regions for a total of six bidding regions. Figure 1, Panel B shows these six regions along with the interregional transmission links between them. The actual physical infrastructure underlying the grid is more complex than shown here, but this structure represents the binding links in the system very well and is therefore used by the system operator to designate available transmission capacity and check for binding transmission constraints. The grid has a central core of the West and East regions. These core regions are connected both to each other and, via separate links, to the demand centers of the North and South 1 regions. The South 2 region is further removed from the core and only accessible via wheeling (i.e., transshipment) of power through South 1. The Northeast region, a source of hydropower, is linked to the core through the East.

The power exchanges manage congestion with market-splitting. The basic idea is to iteratively separate areas with binding constraints and clear them separately. The exact algorithm used is not published and I recreate it here. The market is first cleared unconstrained amongst all regions. I then compare the net demand of each combination of regions and the implied power flows on the grid to both margin constraints, which specify the maximum allowable imports or exports of a region (node), and path constraints, which specify the maximum flows on each path (link) in each direction. If any area violates any constraint, I separate the area with the largest violation on the importing side and declare its imports to be the value of the binding constraint and the exports of the complementary area likewise. I then clear each area separately and check for constraints again, repeating this process until no constraints bind.[8] Bidders in each constrained area receive the area-clearing price in that area regardless of whether the power they buy or sell is imported or exported.[9]

Figure 3 shows the application of the market-splitting algorithm to the same hour for which Figure 2, previously discussed, shows the unconstrained clearance. The unconstrained solution implied a flow to the North region of 571 MW, in excess of its import capacity of

[8]The binding of an internal constraint may relax an outer constraint. E.g. if South 1 and South 2 are initially constrained, and the clearing amongst these regions implies that South 2 is further constrained from South 1, I constrain South 2 from South 1, relax the outer constraint of South 1 from the core and iterate.

[9]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 INR 4.57 billion (USD 91 million) in congestion revenues.

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 3, 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 INR 1000/MWh above the other regions and no further constraints bind once these areas are cleared separately. The Appendix shows that my recreation of this algorithm matches area-clearing prices very well overall.

(c) Transmission Corridor Allocation

Transmission capacity between regions is allocated in a largely administrative manner prioritizing first long-term trade, then short-term contracts and lastly the day-ahead market (Central Electricity Regulatory Commission, 2008a). The net effect of this allocation process is that the day-ahead market becomes the residual claimant on transmission capacity across the system and is greatly exposed to transmission congestion.

Transmission capacity between regions is subject to limits estimated by the system operator. The high-voltage, long-distance power lines that carry power between regions have physical limits on how much power they can carry, determined by engineering standards. These physical limits are not the last word on the declared capacity of a line: because power will flow through all available lines, like water through all available pipes, the flow on a given line may be limited beneath its capacity lest it induce an overload on an adjacent line. The system operator, in this case the National Load Dispatch Centre (NLDC) assumes a generation and load scenario and then determines the allowable limits on the interregional links given the flows this scenario induces in their model of the grid.[10]

The transmission capacity limits so determined are allocated amongst the different platforms for power trade 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, 2008b). The allocation of capacity to long-term trade is roughly constant. Figure 4, Panel A, shows the monthly mean capacity for transmission from East to North, an important, frequently constrained link, for the hour 16:00 to 17:00. The dark bars are the amount of corridor available for long-term contracts and are steady over time, even as the total transmission capacity on this

[10]Like other system operators, the NLDC also allows a reliability margin that assures adequate capacity if any one system element unexpectedly fails.

link, shown by the total height of both bars, grows.[11] 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, 2008a).

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.[12] Figure 4, Panel B shows the results of this process for the sample period of November, 2009 through April, 2010. The horizontal axis is the hour of the day and the vertical axis is the share of transmission capacity given to different types of trade. The lowest, dark portion of the bars is the flat allocation to long-term use. The intermediate portion of the bars is the average amount of corridor booked up by short-term contracts in a given hour. The light topmost portion of the bars is then the average amount of corridor left for the power exchanges. On average more than half of the corridor for short-term use is available for power exchanges. Short-term contracting parties demand more corridor over the middle of the day and particularly around peak times, from 17:00 - 23:00 in the Indian market, to the right of the vertical line. This average encompasses some hours, not shown by the figure, in which short-term contracts exhaust the corridor for all short-term trade completely. There is no pricing mechanism through which day-ahead bidders with high valuations can bid and win back corridor that has already been allocated for long-term use or booked up for short-term contracts.[13]

The residual claimant status of the day-ahead market leaves it with greater transmission capacity available during peak hours than off-peak during the sample period. Note that during the peak hours in Figure 4, Panel B there is significantly more transmission capacity for short-term trade and more capacity left over for power exchanges in particular. Greater anticipated imports of hydro-power from the Northeast during the peak hours relax the constraint

[11] There is also a seasonal component to total directional capacity as the system operator designates some lines for flow in the opposite direction.

[12] 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.

[13] In the Indian market, transmission charges are flat, "postage stamp" charges that apply for any use of the grid and transmission across regions, regardless of the scarcity of transmission at the time of use. During the period of study, for bilateral contracts, the selling party was responsible for a charge of INR 80/MWh for connecting to the national grid and an additional INR 80/MWh for each region through which the power traded is to flow, up to INR 240/MWh for wheeling through one or more regions (Central Electricity Regulatory Commission, 2008a). On the power exchange, transactions are subject to comparable transmission charges of INR 100/MWh separately for the buyer and seller. I neglect these transmission charges in the analysis below as they are small, about 4 percent of the mean energy charge over the period considered, and would not change in any counterfactual scenario.

on East to North transmission during this time by altering the assumptions of the system operator's model.[14] I later use this discrete change in available capacity from peak to off-peak to instrument for congestion in a regression of bid pricing on congestion in the day-ahead market. In Section 4 I discuss the identification assumptions under which this instrument will consistently estimate bidder reponses to congestion.

(d) Data and Study Sample

The analysis uses confidential data from the Indian Energy Exchange (IEX) and the system operator. From the exchange, I use the bids and offers from participants in the day-ahead market. These bids are specified as piecewise-linear functions from price to quantity between up to 64 points, from the price floor of INR 0/MWh to the ceiling of INR 20000/MWh. Most bidders do not use many segments and nearly all segments submitted are flat, so that the bids are step functions in practice.[15] In the Indian market, bidders may offer fewer steps because marginal cost is closer to constant over the relatively small range of offered quantity. I take the step-function structure of bids submitted as given and apply the share-auction framework for modeling bids in terms of incremental quantities submitted at each step.[16] From the system operator, I use transmission constraints for collective transactions (i.e., power exchanges) 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 flows over each inter-regional path in each direction.[17]

I limit the sample to the inclusive period from November, 2009 through April, 2010 to study the bidding response to congestion within a constant regulatory framework. In parts of September and early October, 2009, the day-ahead market was under close regulatory scrutiny and a price cap of INR 8000/MWh was imposed and often bound. Such a binding cap would

[14] The main East to North constraint during this period is Purnea-Muzzaffarpur-Gorakhpur (PMG). Off-peak, this line operates below its physical capacity, as operating at capacity would induce flows to overload the adjacent and heavily-used Farakka-Malda (FM) link. During the peak period additional hydro flow injected at Purnea relaxes the FM constraint and allows PMG to be used at full capacity.

[15] This limited use of a complex strategy space has been noted in bidding behavior in other markets (Hortacsu and Puller, 2008).

[16] See the Appendic.

[17] During the study period, the system operator sent the constraints over the day to the power exchanges only if congestion occurred in any hour of the day in the unconstrained solution. On 7 of 181 days in the sample, no congestion occurred, so the bootstrap simulations and counterfactual will assume that the market was unconstrained on these 7 days.

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 this schedule may influence the opportunity cost of buying and selling power in the day-ahead market for many bidders, the structure of costs underlying bids could have changed at this juncture.

(e) Prevalence of Congestion

During the sample period—indeed, during the life of the power exchanges to date—congestion has been frequent and had a large impact on market prices. 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 the central core of the East and West regions. Figure 5 shows the relationships between inter-regional power flows and regional price differences between the East and North regions and the East and South 1 regions, in Panels A and B, respectively. 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. When the flow between regions is constrained, the constrained areas including each region are cleared separately, and the market-clearing prices in the two regions will differ. Any positive price difference between regions in the figure thus indicates that flows are bound by a transmission constraint. As shown in Panel A, low levels of constrained flow lead to price differences of up to INR 6000/MWh, larger than the average market price. When more corridor is available, the greater flow between regions eliminates or reduces the price difference, creating the negative correlation between price differences and constrained flow in the figure.

Table 2 summarizes the prevalence of congestion during the sample period by comparing the prices of each pair of regions, which only differ if the regions are separated by constrained links. Panel A shows the percentage of the 4344 hours (= 24 hours $\times$ 181 days) over the sample period during which the price in the row region is higher than the price in the column region. The North region is constrained away from the Northeast, East and West regions over 18% of the time during this period. The South 1 region is import constrained with respect to this core 23% of the time and the South 2 region 26% of the time, as the link between the South 1 and South 2 regions also occasionally binds. These constraints create large differences in market prices across regions. 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, i.e. over the scatter plot of points above the horizontal axis in Figure 5, Panel B, is INR 1688/MWh, and between the South 1 and East regions 1655/MWh, each about 38% of the mean unconstrained market-clearing price of INR 4352.90/MWh. In a small number of hours the West and East are import constrained with respect to the Northeast.

3 Model of Supplier Bidding with Transmission Constraints

To measure how transmission constraints affect market outcomes I estimate firm costs and compute counterfactual market outcomes at different levels of these constraints. Firm costs are estimated from supply bid functions using a first-order approach accounting for the effect of transmission constraints on residual demand. This estimation approach, pioneered by Guerre et al. (2000), was adapted for electricity markets by Wolak (2003) and has been applied by Reguant (2011) to study complex bidding in the Spanish market and Allcott (2012) to study real-time pricing applied to the PJM market.

The counterfactual simulations apply a Cournot model wherein strategic bidders set quantities to maximize profits given the residual demand curve and the quantities of competing suppliers in their constrained area. Cournot models have been widely used in empirical analysis of restructured electricity markets and fit market outcomes well when accounting for market structure and institutions like vertical integration (Puller, 2007; Bushnell et al., 2008). The simplicity of Cournot strategies allows for more accurate modeling of transmission constraints in particular (Cardell et al., 1997; Jing-Yuan and Smeers, 1999; Willems, 2002; Neuhoff et al., 2005). Restricting the strategy space of strategic firms is preferable to sharply limiting the number of such firms given the relatively unconcentrated supply in the Indian market, especially as firms use only a small part of the actual strategy space in practice.

(a) Model

The model assumes that strategic firms maximize expected profits by submitting supply functions to the exchange. 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 is represented by a supply function $q_{it}(p)$.[18] 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 ticks b_{itk} of each individual bid and $C_i(\cdot)$ is i's total cost of production. The market clearing condition is that quantity supplied equal residual demand at the market-clearing price, $q_{it}(p) = D_{it}^{rg}(p|\sigma_{-it}, \mathcal{L})$, where $D_{it}^{rg}(p|\sigma_{-it}, \mathcal{L})$ is the residual demand facing firm i in region g, σ_{-it} are the strategies of bidders other than i, including demand bids played by nature, and $\mathcal{L}$ the set of transmission constraints.

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

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

after substituting using both the market-clearing condition and the implicit function theorem.[19] This is a Lerner rule whereby the firm sets prices at marginal cost plus quantity over a weighted expectation of the slope of residual demand. The weights are the slope of the market price in the bid price and can be thought of as the probability that a given bid tick sets the market price. A greater slope of residual demand reduces the optimal markup at each given quantity supplied.

(b) Constrained Residual Demand

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 at price p is

[18] 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 of an incremental quantity when the market price exactly equals the price of the bid tick, with the quantity supplied determined by market clearing.

[19] See the Appendix for further details.

written as:

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

I collect own-region demand bids into D^g, for presentation, letting $j = \{j : j \notin g|q_j > 0\}$, with positive q meaning supply. I designate by $\mathcal{A}_g(p|\mathcal{L})$ the set of regions to which region r is connected by unconstrained transmission lines at a price p and given line capacities $\mathcal{L}$, 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. Let $\mathcal{F}(\mathcal{A}_g|p, \mathcal{L})$ be the net constrained flows into area $\mathcal{A}_g$ at price p and line capacities $\mathcal{L}$.

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

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

assuming that the constraints are not exactly binding, so that a small change in price does not change $\mathcal{A}_g(p|\mathcal{L})$. This assumption appears reasonable given the uncertainty faced by bidders as it is unlikely constraints will exactly bid for a given realization of demand and other supply bids. The smaller is the constrained region $\mathcal{A}_g(p|\mathcal{L})$, the weakly smaller (closer to zero) 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 constrained area $\mathcal{A}_g(p|\mathcal{L})$ is determined using the market-splitting algorithm employed by the power exchange and described in Section 2. 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. In principle there may be multiple equilibria with different constrained areas. This prospect does not affect estimation using the local first-order necessary conditions but may matter for counterfactual simulations, as discussed in Section 3 (c) below.

Constraints do not unambiguously raise bid prices or reduce offered quantities. The overall effect of transmission constraints on supply bids will depend on the shape of the constrained and unconstrained residual demand curves. 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. A bidder may therefore expect bid ticks higher (lower) in the 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 or lowering of price for any given quantity. Conversely, a supplier in an import-constrained region gaining a greater market share and serving greater inframarginal quantity than when unconstrained would tend to lead to increases in mark-ups, magnifying the effect of lower residual demand slope.

(c) Cournot Counterfactual

To simulate counteractual outcomes I use a Cournot model for a set of strategic firms. 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. This set of thirteen strategic firms covers 71% of all offered sell volume. 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, making a smooth approximation to the residual demand curve in each region reasonable.

Consider a set of strategic firms i with marginal costs γ_i facing a residual demand curve $D^g(p|\sigma_{-it}, \mathcal{L})$ with twice-continuously differentiable inverse residual demand curve $\tilde{P}^g(Q^g|\sigma_{-it}, \mathcal{L})$, where Q^g is aggregate strategic quantity offered in region g. The derivative of profit with respect to the seller's offered quantity q_{it} is:

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

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

$$q_{it} \in (0, \overline{q}_i) \quad \perp \quad f_{it}(q_{it}) \neq 0$$

$$q_{it} = 0 \quad \perp \quad f_{it}(q_{it}) \geq 0$$
$$q_{it} = \overline{q}_i \quad \perp \quad f_{it}(q_{it}) \leq 0.$$

Here $\overline{q}_i$ is the quantity constraint for the strategic seller. If the seller produces a quantity between zero and their constraint, then it must be that the derivative of profits with respect to quantity at that point are zero. Similarly with the non-negativity and quantity constraints and their corresponding inequality constraints. 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).

An example of the solution to the model is shown in Figure 2, Panel B. Panel A is the actual market clearance, previously discussed, and Panel B the Cournot model simulation for the same hour. In Panel B the increasing solid curve represents the marginal cost curve for strategic suppliers. 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 smoothing is over quantity with a bandwidth equal to ten percent of the quantity range of the residual demand curve. The vertical line is the equilibrium strategic quantity offered by the strategic suppliers, at which the above 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 the actual clearing price seen in Panel A.

The above problem applies to the residual demand curve faced by each seller within their own constrained area. The solution algorithm mimics the market-clearing 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. Simulations of market outcomes use the realized residual demand curve, composed of all demand bids and fringe supply bids, to solve for market equilibrium. The strategic quantities offered are therefore *ex post* optimal with respect to the smoothed inverse residual demand curve.

The Cournot model used does not guarantee a unique equilibrium. Transmission constraints can theoretically produce multiple equilibria, with lines congested in different directions, or leave no pure-strategy equilibria at all. In real markets with asymmetric firms and demand across regions a pure-strategy equilibrium of the Cournot model will virtually always exist (Borenstein et al., 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, is conducive to there being a single pure-strategy equilibrium, as it will seldom 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.

Congestion aside, the varied shape of the residual demand curve complicates the search for an equilibrium. The Indian market is well-suited to the Cournot model, amongst electricity markets, as a relatively active demand side at the wholesale level leads to reliable price formation in the model. However, 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.[20] I discuss the empirical relevance of equilibrium selection in Section 5.

4 Estimation Strategy

(a) Reduced-form Response to Congestion

The primary implication of the model is that when a supplier's region is constrained, the only elasticity of residual demand he faces is from own-area demand and supply bids, as outside competition is sealed off. At a given price, the elasticity of residual demand will drop, tending to cause suppliers to raise prices, as they can do so without losing as much quantity.[21] Competitive suppliers bid their marginal cost curves regardless of the level of transmission constraints. Therefore looking at how bids change with congestion will be informative about the extent of market power in the day-ahead market.

The main reduced-form specification is a simplification of the first-order condition for

[20] Sufficient conditions for the uniqueness of Cournot equilibria generally require pseudoconcavity of profit functions, which, given constant marginal costs, they must inherit from the demand function (Kolstad and Mathiesen, 1987).

[21] As suppliers' inframarginal quantities and the distribution of expected marginal prices will also change, the magnitude and even sign of the change in markups is theoretically ambiguous.

profit maximization. Solving equation 1 for bid price we have:

$$b_{idh}(q_{idh}) \quad = \quad C_i'(q_{idh}(p)) - q_{idh}(p)\frac{\partial D_{idh}^{rg-1}(p|\sigma_{-idh}, \mathcal{L})}{\partial p} + \varepsilon_{idhp},$$

where I have replaced time subscripts t with date and hour subscripts dh and added an econometric error. This relationship holds in expectation for each optimal bid tick price when each tick is weighted by the probability of a bid price being marginal. The error term reflects cost and demand shocks that would cause submitted bids not to be *ex post* optimal. The main reduced-form specification is then:

$$b_{idh}(q_{idh}) \quad = \quad \gamma_{0i} + \gamma_{1i}q_{idh} + \gamma_{2i}q_{idh}^2 + \beta_1 \cdot Cong_{rdh}(p|p = b_{idh}) + \alpha_d + f(h) + \varepsilon_{idhp},$$

where i indicates a seller, d a date, h an hour and p a bid price. The intercept and quantity terms q_{idh}, q_{idh}^2 control for cost at the level of the seller and α_d and $f(h)$ are date fixed effects and a polynomial in hour-of-day to control for cost and demand conditions. I do not include hour fixed effects or interactions as these would wholly absorb the variation in the instrument from off-peak to peak hours. The supply bids for each supplier in the North region are represented by price-quantity pairs where the prices are a uniform set from INR 2000/MWh to INR 8000/MWh at INR 500/MWh intervals, so that each seller-hour contains thirteen observations. Observations are weighted by the probability that each bid price b_{idh} sets the market-clearing price, approximated by the unconditional density of market-clearing prices over the period. I replace the product of inframarginal quantity and inverse residual demand slope with a single summary measure of congestion to measure the average bidder response to congested conditions. The variable of interest is the coefficient β_1 on a dummy for whether the market would be congested if the North region price were equal to the price bid.[22]

The coefficient of interest is not consistently estimable with ordinary least-squares because congestion is endogenous to the econmetric error. Congestion varies both because transmission constraints vary and because market conditions change due to cost and demand shocks. For example, a high cost shock for a supplier in the North region would cause that supplier to

[22] Both the weights and the construction of this dummy are theoretically appropriate. The bidder does not care about congestion at only the realized market-clearing price but at each price being bid. I therefore construct a dummy for congestion at each bid price using the *ex post* bid realizations.

offer less quantity at every price. This would raise the level of imports at every price and make congestion more likely to occur. In this case, the estimate of β_1 would then be biased upwards from conflating cost shocks with congestion. In order to isolate the bidder response to congestion I use the allocation of transmission corridor for short-term trade, described in Section 2 (c), as an instrument for congestion in the above regression.[23]

The exclusion restriction is that, conditional on date and controls for hour of day, the allocation of transmission corridor for short-term trade does not influence supply bid prices other than through congestion. This allocation is set three months prior to delivery and is a residual of the total amount of corridor available less a roughly constant allocation to long-term trade. In particular, the within-day variation in this allocation, shown in Figure 4, Panel B, is driven by differing assumptions in the system operator's model for peak and off-peak periods. These assumptions, set well in advance, are not endogenous to short-term cost or demand shocks. A more plausible violation of the exclusion restriction would be if demand bids in the North region also changed in response to anticipated congestion, so the supplier response measured was not to congestion alone but to own-region demand. In this case rejecting that $\beta_1 = 0$ would still indicate non-competitive behavior but the magnitude of response would be difficult to interpret.

(b) Estimation of Structural Model

The estimation procedure uses the first-order condition above to recover estimates of the marginal cost of supply for firms in the day-ahead market with the generalized method of moments. The marginal cost of each firm is a behavioral cost, in the terminology of Wolak (2007), which accounts for not only the technological costs of generation but also the opportunity cost of selling in the day-ahead market. This distinction is especially important in the Indian market where the alternative to selling in the day-ahead market, for some bidders, may be to generate power for industrial production.

To approximate the uncertainty faced by firms in the day-ahead market 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 discussed

[23] I use the total allocation for short-term trade, including both contracts and the day-ahead market, as the actual constraint in the day-ahead market, as the residual of transmission capacity, is endogenous to bookings for corridor in the contract market.

in Section 2 (c) and the bidder types are State Generating Companies, Private Generating Companies, Distribution Companies and Industrial Firms. When there is a single bidder of a given type in a given region, this procedure maintains its identity, while when there are many bidders, such as industrial consumers on the demand side, it replicates the uncertainty of such firms dropping in and out of the market. Other bidder-days are drawn with weights in proportion to a triweight kernel in distance from the day for which uncertainty is being simulated with a bandwidth of 14 days.

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

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

where $s \in \{1, \ldots, S\}$ are bootstrap iterations, $H(h)$ is the set of times with hours equal to h, and a tilde indicates a smoothed function. Every bootstrap draw of bids $\sigma^{\mathbf{s}}{}_{-i}$ 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, is strictly zero at almost all prices. I 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 (Wolak, 2003). The Appendix describes this procedure. In the base estimation I take the smoothing bandwidth to be INR 500/MWh, which is 11% of the mean unconstrained market-clearing price and 21% of the standard deviation in this price, and the number of bootstrap simulations to be $S = 100$.

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.[24] Given the small range of supply from most participants in the day-ahead market, relative to other markets or their own generation portfolios, constant marginal costs are likely to be a good approximation. Moreover, the average sell bid described in Table 1 has only about two

[24] E.g., Gans and Wolak (2008) use constant marginal costs to study vertical integration and the models reviewed in Neuhoff et al. (2005) that incorporate transmission constraints mostly use piecewise constant marginal costs, whereas Reguant (2011) estimates linear marginal costs with adjustment cost to capture dynamic firm decisions important to the study of complex bidding.

bid ticks and only three strategic sellers average over three steps per offer. This limits the variation available to estimate any slope of marginal cost for most bidders.

I estimate the marginal cost parameter γ_i for each strategic seller by averaging the moments $m_{ikh}(\gamma_i)$ over four equal hourly blocks and solving for the GMM estimator that minimizes the inner product of the empirical moments. Standard errors are bootstrapped by resampling with replacement one hundred draws from the one hundred replications of market outcomes and estimating the cost coefficients for each set drawn. I also estimate a capacity constraint for each seller as the maximum offered quantity in the market for each seller over the sample period. As the first-order conditions are with respect to price, the capacity constraints do not violate the first-order approach: 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.

5 Results

(a) Reduced-form Results

Table 3 presents results from the instrumental variable specification discussed in column 4 and related specifications in other columns. The first and second columns omit date effects and the first column additionally omits bidder-specific quantity controls in favor of a single quantity quadratic for all bidders. These columns therefore use variation in short-term corridor allocated across months as well as the change from peak to off-peak. The estimated coefficient on congestion is an increase in price of around INR 1600/MWh, which is coarsely estimated but significant if bidder-specific quantity controls are included (column 2). These estimates are as large as the ordinary-least squares estimates for the same specifications, suggesting the instrument is not purging the endogeneity of congestion. This will be the case, for example, if there are shocks to demand or cost across months that are correlated with congestion and bid prices. The first-stage coefficient, shown in Panel B, is indeed small. Monthly variation in short-term corridor may be correlated with demand over this period; in particular, a decrease in corridor from November, 2009 onwards corresponds to a period of demand growth, which may overstate the effect of congestion itself on bid prices. I therefore prefer the specifications in columns 3 and 4 that use date fixed-effects to eliminate monthly variation and use only the variation in corridor allocation within-day as an instrument.

In these preferred specifications the first-stage shows a significant relationship of the expected sign. An increase of 100 MW in short-term corridor allocation decreases the likelihood of congestion by 3.1 percentage points. The coefficients on congestion in the corresponding specifications are approximately INR 742.3/MWh (column 4, standard error INR 117.5/MWh) regardless of whether aggregate or bidder-specific quantity controls are used.[25] This represents an increase in bid price of 17% of the average unconstrained market-clearing price. These coefficients are about the same when looking at public and private bidders separately, with coefficients of INR 970.5/MWh and INR 604.9/MWh in specifications corresponding to that in column 4 (not shown). Bidders responded to congestion by raising prices bid. The increase in bid prices does not account for all of the rise in market-clearing prices, shown in Table 2, as would be expected if demand shocks also contribute to congesting the lines.

This reduced-form approach gives suggestive evidence that bidders raise prices in response to congestion but has several limitations. Because the usable variation in short-term corridor allocation is limited to changes from off-peak to peak within the day, the admissible hour controls are rather coarse, lest they eliminate the variation used by the instrument. Taking the specification of column 3, the estimated effect of congestion on bid prices is the same (INR 864.4/MWh) with quadratic, instead of cubic, hour controls, but falls sharply with separate peak and off-peak quadratic functions (INR 130.1/MWh) that absorb the variation within-day used by the instrument. More broadly, the nature of the bid response induced by this change in capacity within-day may be very different than the response for a constraint that binds more than marginally, under different demand conditions or at other times. The next section introduces a model of supplier bidding that uses all the variation in the data to estimate supplier costs and thus margins. With these estimates I can then simulate the competitive effects of relaxing transmission constraints for the market as a whole.

(b) Estimated Marginal Costs

The characteristics and estimated marginal costs of strategic sellers are shown Table 4. There are four strategic sellers in the North and nine in the West. They are a heterogeneous lot, representing all of the four broad bidder types that bid on the exchange: state utilities,

[25]These are far smaller than the corresponding ordinary-least squares coefficients of 2067.9 and 1681.3 for columns 3 and 4, respectively.

distribution companies, 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.[26] Industrial plants have small shares of overall market volume but offer significant volume of up to 250 MW in some hours.[27] 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 estimate marginal costs of these suppliers are presented in column 6. The range of cost estimates is broad but reasonable. The estimated costs for individual sellers range from a low of INR 680/MWh up to a high of INR 5923/MWh, with both extremes coming from industrial plants. The opportunity cost of supply in the day-ahead market is likely to be different from the pure technological cost of generation for industrial plants, which can alternately use the power themselves.[28] Larger discoms and state utilities have estimated marginal costs in the INR 2500/MWh to INR 4000/MWh range. By seller type, the mean cost estimates in ascending order are INR 1940/MWh for private generating companies, INR 2992/MWh for industrial plants, INR 3087/MWh for distribution companies and INR 3177/MWh for state utilities.

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 INR 645/MWh or 26 percent of cost. All types of bidders have markups between INR 600/MWh and INR 700/MWh. Private generating companies have similar absolute markups to other sellers, at INR 630/MWh, but lower costs and therefore larger markups in percentage terms. The estimated marginal costs are reasonable in terms of the observed bids from which they were estimated.[29] Note that, in light of these estimates, the estimated increase of bids of INR

[26] The Herfindahl index for unconstrained offered volume by all sellers is 0.092.

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

[28] One interpretation of the low cost of supply from a single industrial seller is as reflecting power from a plant or set of plants that overbuilt captive generation capacity but needs to produce at some minimum stable load.

[29] One industrial plant has estimated costs above the weighted mean offered tick price. Given that this seller's average offers are only about half of the market-clearing price, it is likely that many of this seller's offers are too far from marginal to influence the estimated costs, which are estimated to be greater in order to fit higher offers from the same seller better.

742/MWh in response to congestion, from Table 3, represents an approximate doubling of price-cost margins.

These estimates are consistent with the available information on generating costs in India. A limitation of the data is that the bidders are anonymous so the generation technology used by each seller is 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 energy and 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 INR 2192/MWh for coal stations not at the pit-head, INR 2193/MWh for natural gas units and INR 4668/MWh for liquefied natural gas units. These are broadly consistent with but somewhat below the costs I estimate, which is sensible given that long-term power-purchase agreements are more likely to rely on low-marginal-cost baseload plants.

A striking conclusion from the estimation of marginal costs is that a very high cost structure is not necessary to rationalize high market prices. Market prices have a mean of INR 4352/MWh and a standard deviation of 2426/MWh, and transmission constraints routinely create regional differences in price of INR 2000/MWh or more. Yet these conditions do not imply, through the model, costs are unreasonably high overall or in the constrained North region in particular. Rather, given the shortage of electricity in India, the day-ahead market represents the right side of the aggregate cost curve in a power sector that is very often peaking.

(c) Model Fit

Before turning to counterfactual outcomes it is important to understand the fit of the constrained Cournot model in the baseline case. Table 5 compares actual market outcomes, in columns 1 and 2, with outcomes for the constrained Cournot model with the same amount of transmission capacity. The overall fit of the model is good, though it performs better at matching patterns of congestion and regional price differences than the levels of unconstrained market outcomes. For example, the model overpredicts unconstrained quantity and therefore underpredicts unconstrained price by 15 percent (INR 665.73/MWh on a base of INR 4352.90/MWh). The model matches the patterns of congestion and price differences induced by congestion extremely well. The North region is import constrained with respect to the West region 16 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 INR 1437/MWh in the model and INR 1685.38/MWh in the actual market clearance. The North region and West region have similar, though somewhat larger in magnitude, 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 although the model somewhat overpredicts congestion. Overall the model fits market outcomes very well, especially considering the parsimony of the specification.

Two primary factors explain the model tendency to overpredict unconstrained quantities and therefore underpredict prices. First, as a baseline case I have taken the capacity constraints in every time period to be the maximum quantity offered by a seller over the entire sample period, as shown in Table 4 column (4). Sellers may not have this maximum capacity available over the entire sample period, especially if it was contracted out during some months. To test the importance of this idea I instead let the capacity constraint be the maximum capacity offered by a seller in a given month.[30] This increases the average price predicted by the model by INR 101/MWh to INR 3788/MWh, improving the fit. Allowing stricter capacity constraints at higher frequencies would raise predicted prices further. Second, the counterfactual model does not represent the uncertainty faced by sellers. When facing a residual demand curve of the nature of Figure 3, Panel B, where price drops off very steeply after the equilibrium quantity, introducing uncertainty would likely induce sellers to choke back quantities supplied, raising prices. Uncertainty over the residual demand curve may therefore improve the fit. I do not introduce uncertainty in the counterfactuals given that the model matches the outcomes of interest with respect to transmission congestion well already and that model scenarios will be compared to one another to determine counterfactual changes in welfare.

Equilibrium selection is decidedly not responsible for the model's overprediction of quantity. In the baseline simulation I initialize the search for an equilibrium at the point where all strategic sellers equally supply 75% 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

[30]The mean of the standard deviation of maximum capacity each month as a share of overall maximum capacity is 21 percent, a modest but significant change.

selected by firms, in accord with the discussion of Section 3 (c). I test for the importance of equilibrium selection by instead allocating strategic sellers 25% of the maximum residual demand to start. This produces an average unconstrained market price of INR 3689.49/MWh over the sample period, basically indistinguishable from the price of INR 3687.16/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. That the equilibrium found by the model is basically always unique 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 3, Panel B.[31] In principle this can create distinct concave portions of residual demand where equilibria might be found. In practice, though, the potential equilibria 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.

(d) Counterfactual Transmission Expansion

As counterfactual scenarios I consider expansions of the transmission capacity available to the two most frequently constrained regions, the North and the South. Specifically I consider expansions of the import capacity of the North and South 1 regions of 400, 800 and 1200 MW, where the expanded capacity is split equally between the paths from East to the constrained region and West to the constrained region.[32] Market outcomes with expanded transmission capacity are shown in Table 6. Panel A of the table considers expansion of the links leading to the North region and Panel B to the South 1 region. The top portion of each panel shows select market outcomes holding strategic bids fixed at baseline levels and the bottom level of each panel allows bids to adjust endogenously to the new level of constraints.

Consider the effect of expanding the North region's import capacity while holding strategic bids fixed. An expansion of only 400 MW reduces congestion sharply, from 16 percent of hours to 2 percent of hours, and of 800 MW eliminates congestion almost entirely. The price difference conditional on congestion for the remaining congested hours remains fairly high. The North region increases its net demand somewhat by purchasing more from other regions;

[31] 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.

[32] Given that the East to West link has a high capacity the allocation of the expansion has a small effect on the results.

the West region net demand holds steady. Market surplus, shown in the fourth row of the top of Panel A, increases by INR 0.02 million per hour, barely perceptible on a base of INR 3.26 million per hour. This effect is a composition of an 11% increase in surplus for buyers, who in the North region get cleared at lower prices, and a 6% decline for sellers, who also get cleared at lower prices. Note that in the baseline case fully 74% of the market surplus goes to the sell side of the market during this period. This asymmetry is not only due to the generally high market prices, but is driven by the fact that buyers have outside options for the procurement of power. They therefore bid a very elastic demand curve and set the marginal price and are then often indifferent to buying or not.

The welfare gains with endogenous response of strategic sellers are larger than when holding bids fixed. When bidders respond endogenously, the West region increases supply to serve demand in the North region. The share of congested hours decreases with transmission expansion, but more slowly than with fixed bids, as sellers in the West region recongest the line by offering greater quantity. For example, at a 400 MW expansion in column 2, the North price is greater than the West price in 7 percent of hours, as opposed to 2 percent of hours holding bids fixed. By 800 MW, in column 3, congestion lingers in 2 percent of hours with endogenous bids but has disappeared with fixed bids. In contrast to the case with fixed bids welfare improves overall with endogenous bids. Sellers are no worse off after the transmission expansion, as they increase quantity to compensate the loss of profits due to lower prices. Buyers are significantly better off. The net result is that surplus rises 5 percent when bids are allowed to adjust.

Table 6, Panel B shows the effects of an expansion of capacity leading to South 1. The South 1 region is frequently import constrained relative to the West region, but as suggested by Figure 1, Panel B, this is in part because it is the only path of transit to the South 2 region, which is a greater source of demand and itself sometimes constrained relative to South 1. Expanding South 1 region import capacity holding bids fixed increases welfare, unlike for the North region. Buyers overall are not much better off, indicating that buyers in the South 1 and South 2 region may demand a large quantity but not at much higher willingness-to-pay than the buyers outside the South that were being cleared in the baseline case. Strategic sellers in the North and the West regions benefit from being able to serve the South region demand, which raises prices in their areas.

The effect of endogenous bidding on the benefits of capacity expansion are much greater for expansion of the import capacity of the South. Overall surplus rises by fully 14 percent with the response from strategic bidders as opposed to 5 percent with fixed bids for an expansion of 1200 MW, which almost, but not quite, eliminates congestion to the South 1 region. Sellers, despite lower prices in the South, are better off for being able to serve the demand in the South region. Buyer welfare increases by 23 percent. The South 1 region actually shifts from a marginal net seller to a net buyer with the capacity expansion as it is now able to consume power itself rather than sell it onward to higher-value consumers in the South 2, as had often been the case when the South 1 and South 2 regions were constrained from the rest of the grid together.

Accounting for competitive effects, then, shows that a greater expansion of transmission capacity is required to relieve congestion as strategic sellers compete in newly accessible regions. The welfare gains from transmission expansion, however, are correspondingly larger as a greater quantity gets cleared for higher-value buyers. Figure 6 summarizes the welfare gains for counterfactual increases of transmission capacity. Panel A shows expansions of capacity into the North region and Panel B into the South region. In each panel, the thin (red) lines represent surplus holding strategic bids fixed at the baseline level while the thick (black) lines represent surplus allowing strategic bids to adjust endogenously to the new level of transmission constraints. Within each scenario, the dotted line represents buyer surplus, the dashed line seller surplus and the solid line total surplus. Each surplus measure is scaled by subtracting the baseline surplus for each group and dividing by the total surplus for all groups. With bids fixed at baseline levels, one party, the sellers in the North or the buyers in the South, are left worse off or no better off after the expansion, which allows somewhat greater trade but primarily shifts surplus amongst bidders. Sellers are better off at each level of expansion, by the very fact that they can adjust bids. Buyers are better off with an expansion sufficient to eliminate congestion but would prefer sellers not adjust bids for intermediate levels of transmission expansion in the North.

Welfare increases by much more when sellers adjust their bids to the transmission constraints, as shown by the difference between the thin and thick solid lines in the figure. The ratio of the aggregate welfare gain from both expansions (done independently) with endogenous bids to the gain with fixed bids is 3.55; i.e., the strategic response to the expansions accounts for 72% of their welfare benefit. In aggregate with endogenous bids, the 1200 MW expansions to the North and South regions would have increased welfare by INR 1.39 billion (USD 27.80 million) and INR 4.08 billion (USD 81.67 million), respectively, with the bulk of this gain coming from the competitive response of bidders.

6 Conclusion

The Indian day-ahead market is a foothold for market signals in a turbulent power sector. Though this market handles a relatively small share of trade in India, it is important for being an open platform, shared by a wide variety of market participants, and on which transmission congestion directly affects energy prices. The volume of trade on the day-ahead market has also grown rapidly since its inception, for example by 53 percent from fiscal 2009 to 2010, and it is not hard to imagine this market handling a significantly larger share of volume in the future. The prospects for such growth depend in large part on the availability of transmission capacity to allow trade between regions with private investment in generation such as the West and load centers in the North and South.

I study the effect of transmission constraints on supplier bidding and welfare in the day-ahead market over the period from November, 2009 through April, 2010. Using confidential data on bids, offers and transmission constraints, I estimate the bidder response to congestion in reduced-form and formulate a model to measure the counterfactual gain from expansions of transmission capacity. There are three main findings. First, bidders in the frequently-congested North region increase prices bid by 17 percent in response to congested conditions induced by regulatory allocations of transmission. Second, despite generally high market prices and the price spikes caused by congestion, firm marginal costs estimated from bidding first-order conditions are comparable to published cost estimates for the industry. High prices are the result of the structure of the market and transmission constraints rather than high input costs *per se.* Third, counterfactual expansions of transmission sharply increase welfare, with most of the gain to market participants coming from the endogenous response of strategic suppliers to relaxed constraints. The strategic response to transmission expansions accounts for 72% of the gain in surplus.

These findings are based on considering transmission expansion in the day-ahead market in relative isolation and may understate the welfare gains of such investment. Relaxing transmission constraints would likely induce additional participants to shift out of the short-term contract market, which is presently favored in the transmission allocation process, and into the day-ahead market, increasing liquidity, lowering transaction costs and bringing trade closer in time to realizations of demand (Mansur and White, 2012). Moreover, there are likely also welfare gains from improving the allocation of existing transmission capacity even without physical investment. Participants in the long-term and short-term contract markets reserve transmission capacity far in advance of delivery at prices that do not reflect the eventual scarcity of these lines. This is in contrast to other power markets with zonal pricing where the allocation of transmission capacity is done in a uniform manner close to the date of delivery based on willingness-to-pay for energy (e.g., Nordpool). Even the long-term customers, which receive favored treatment because they are charged to support the grid, could benefit from a mechanism allowing them to sell capacity back to high-value short-term users on the power exchanges.

To my knowledge this is the first micro-economic study of an open power market in a developing country. There is an extensive literature on the exercise of market power in deregulated electricity markets around the world and the importance of market design in mitigating market power (Joskow, 2008). Market power is potentially much more important for welfare in developing markets. Market power in mature markets affects production efficiency but not allocative efficiency (Borenstein et al., 2002). When a generator withholds capacity that would be competitive to operate, raising prices, less efficient generators will be called to make up the gap. Consumers are served in any case, though this behavior may raise prices in the long-term. In India's deficit market, in contrast, power withheld may increase demand not met, from any source, leading to load shedding and large welfare losses. The day-ahead market may be the last chance for a distribution company to procure power rather than cutting customers off. Compare India's average power deficit of ten percent with the one-day-in-ten-years standard for any load shedding of the Northeast Power Coordinating Council (NPCC) in the United States (Central Electricity Authority, 2011). Unreliable, scarce power supply not only hurts consumers but also reduces the productivity of firms (Fisher-Vanden et al., 2012). The extent of firm investment in captive generation gives some sense of the cost of unreliable power. India has an additional 13% of the total capacity of utilities, about 25,000

MW, invested in captive capacity with high marginal costs and low load factors Nag (2010). A shortage of energy due to transmission constraints or other factors likely has effects on firm investment and output in the long-term.

Electricity markets are especially prone to the exercise of market power, so power transmission infrastructure may be expected to have especially large competitive effects. There is a range of other public infrastructure that may also have competitive effects by promoting arbitrage across space and time. Jensen (2007) is an example of the competitive effects of communication infrastructure. Better transport infrastructure may encourage competition by lowering trade costs directly and expanding access to markets. Public infrastructure provided by the government or agricultural cooperatives for the storage or processing of agricultural goods may have competitive effects dependent on the local market structure for these commodoties. How infrastructure interacts with market structure to determine market outcomes is an important area for future research beyond deregulated electricity markets.

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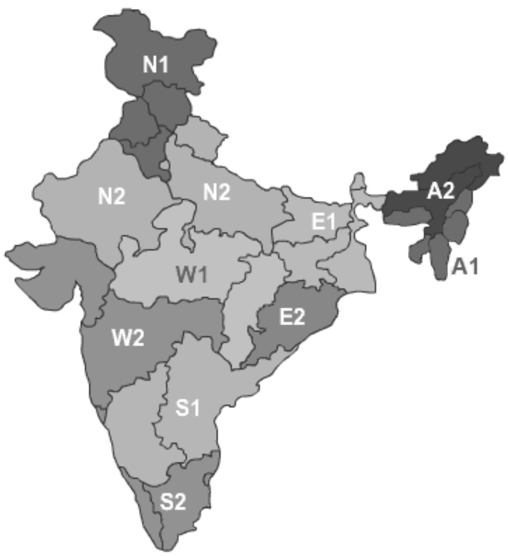
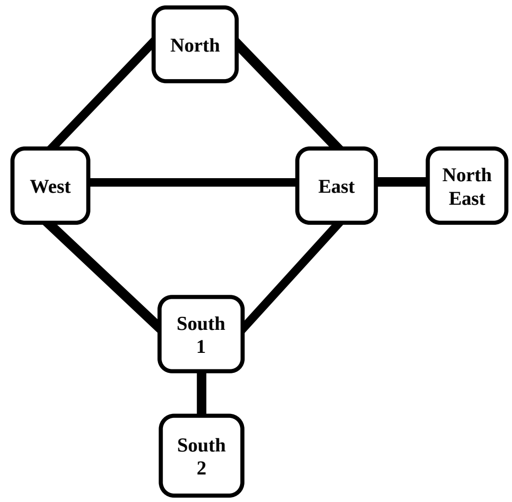
8 Figures

Figure 1: Indian Power Grid

A. Power Exchange Bidding Areas

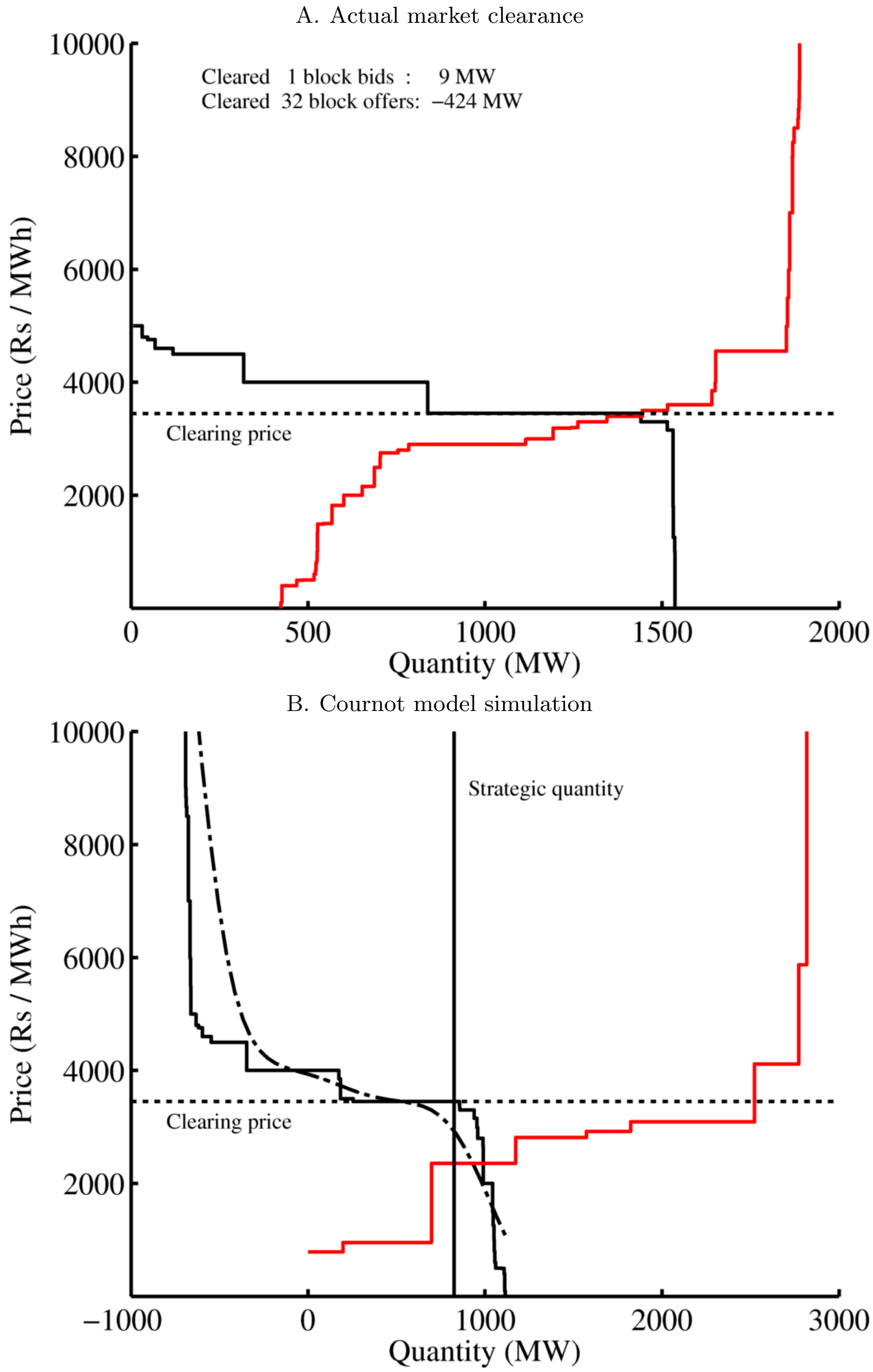


B. Schematic of Ever-constrained Regions



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.

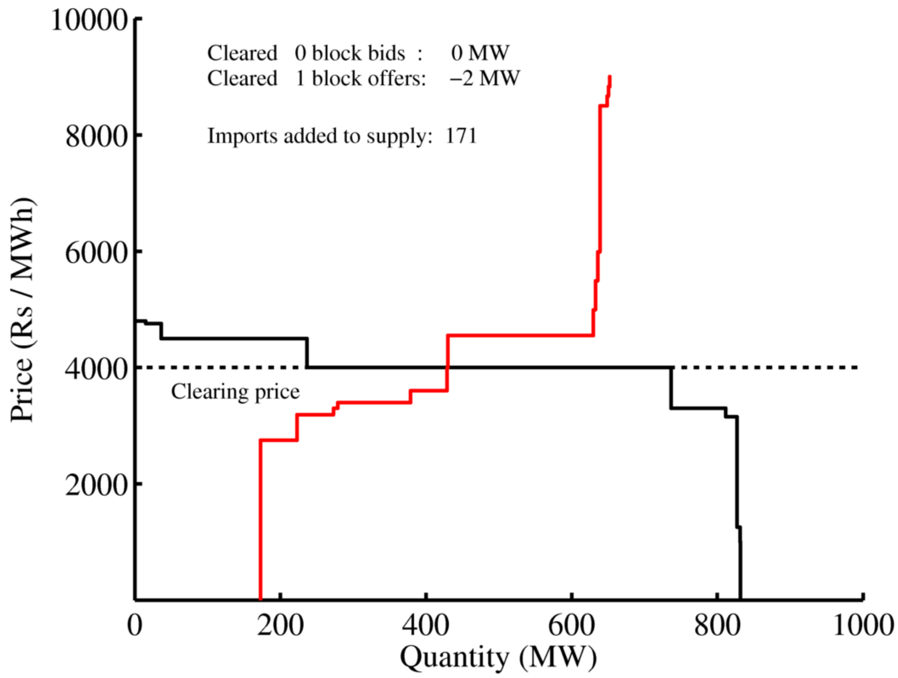
Figure 2: Unconstrained Market Clearance
January 26th, 2010, hour 17



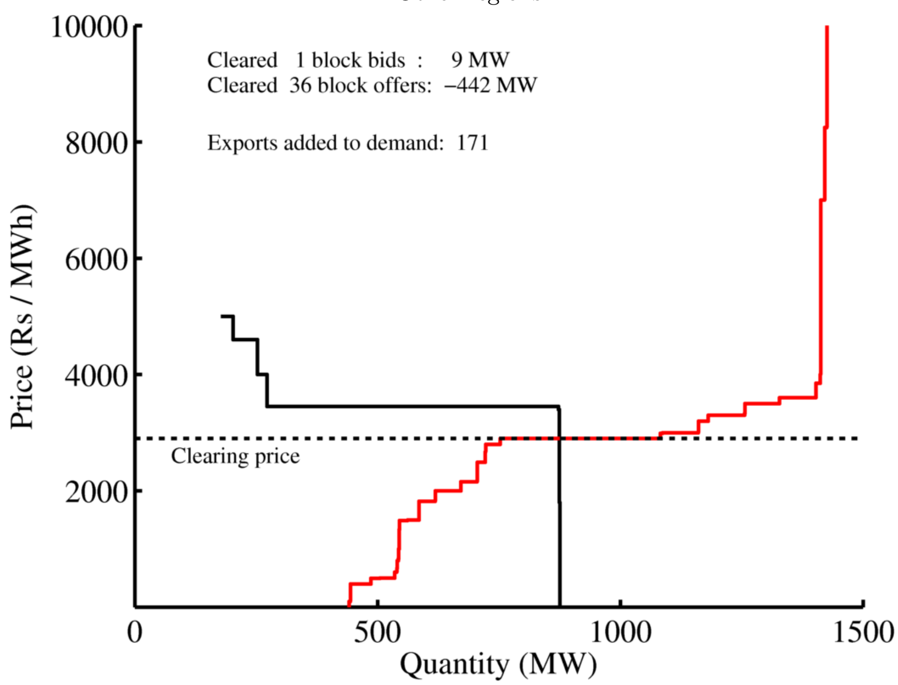
The figure shows the unconstrained market clearance on the Indian Energy Exchange during January 26th, 2010, hour 17. Panel A shows the actual market-clearing price as determined by the intersection of the downward-sloping demand curve and upward-sloping supply curve, where each curve has been shifted 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: Constrained Market Clearance
January 26th, 2010, hour 17

A. North region



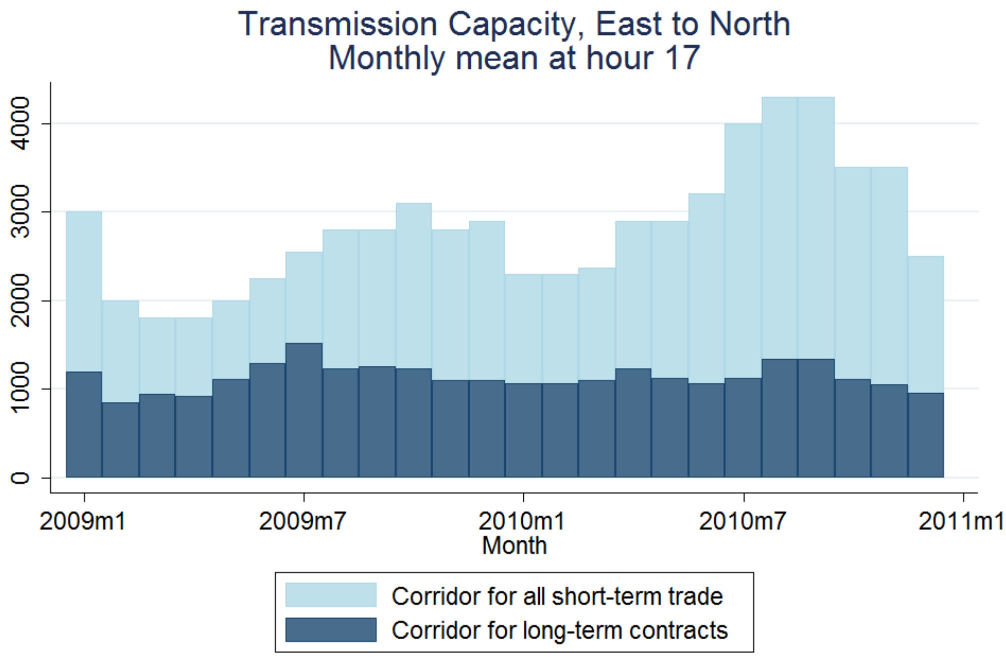
B. Other regions



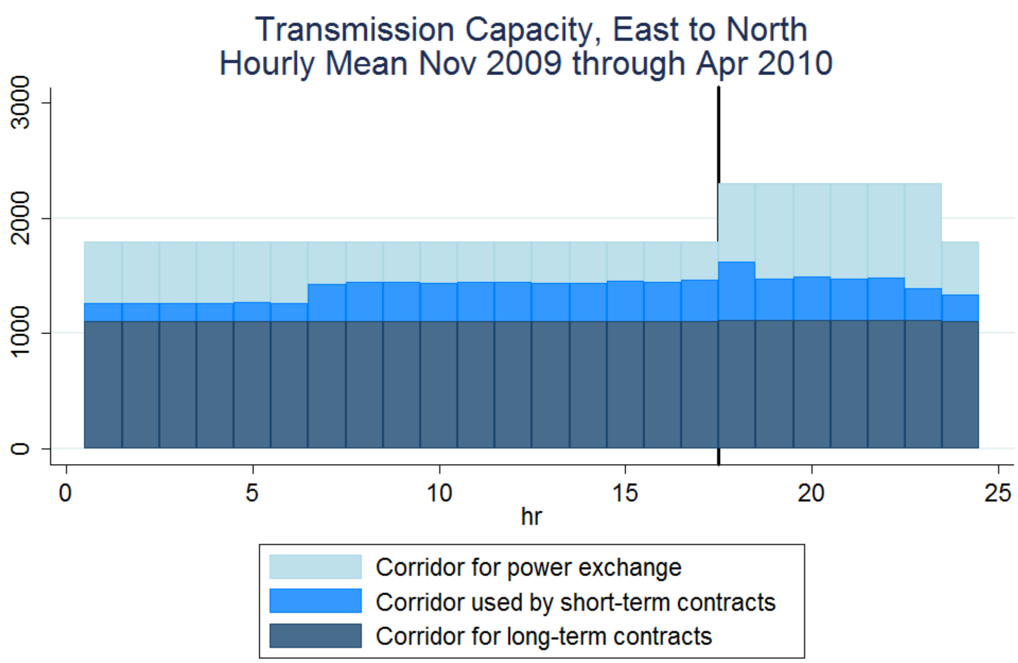
The figure shows the constrained market clearance on the Indian Energy Exchange during January 26th, 2010, hour 17. The unconstrained market clearance shown in Figure 2, Panel A implied a flow of 571 MW to North region when only 171 MW of import capacity was available. The market was therefore split 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.

Figure 4: Transmission Capacity Allocation

A. Monthly, 2009 through 2011 Q1



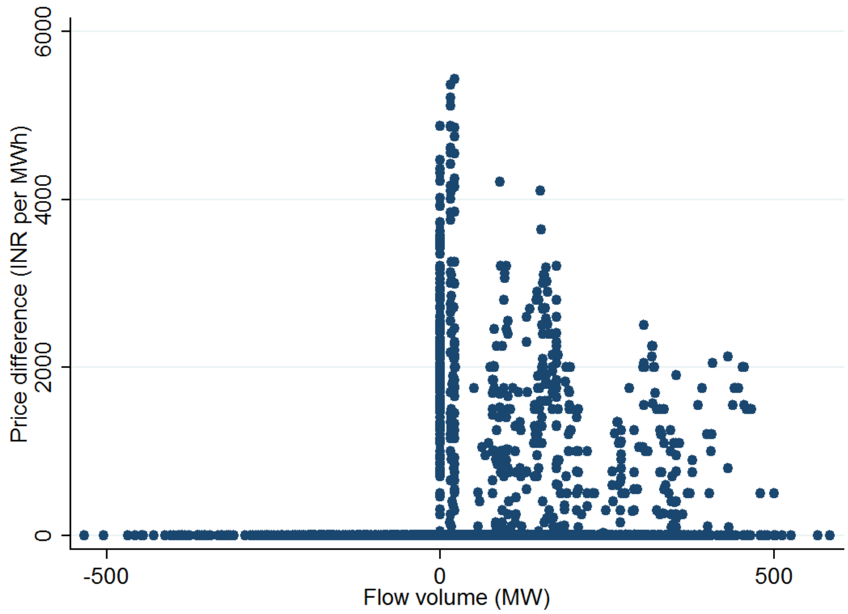
B. Hourly average, sample period



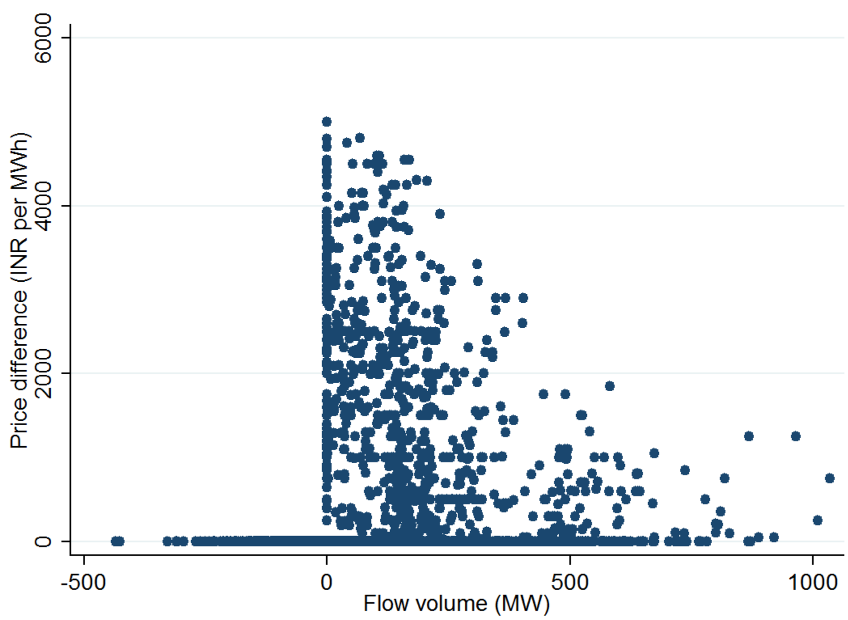
The figure shows the allocation of transmission capacity from the East to the North region by the system operator for different horizons of electricity trade during different time periods. Panel A shows the monthly average allocation of corridor for long-term contracts and short-term trade during the 17th hour of the day (16:00-17:00). Panel B shows the hourly average allocation of corridor for long-term contracts and short-term trade over the sample period. The intermediate bars are the average amount of corridor allocated for short-term trade actually booked by short-term contracts. The power exchange is allocated the residual corridor left by the light, top-most bars.

Figure 5: Regional Price Differences Against Interregional Flows

A. East to North, sample period



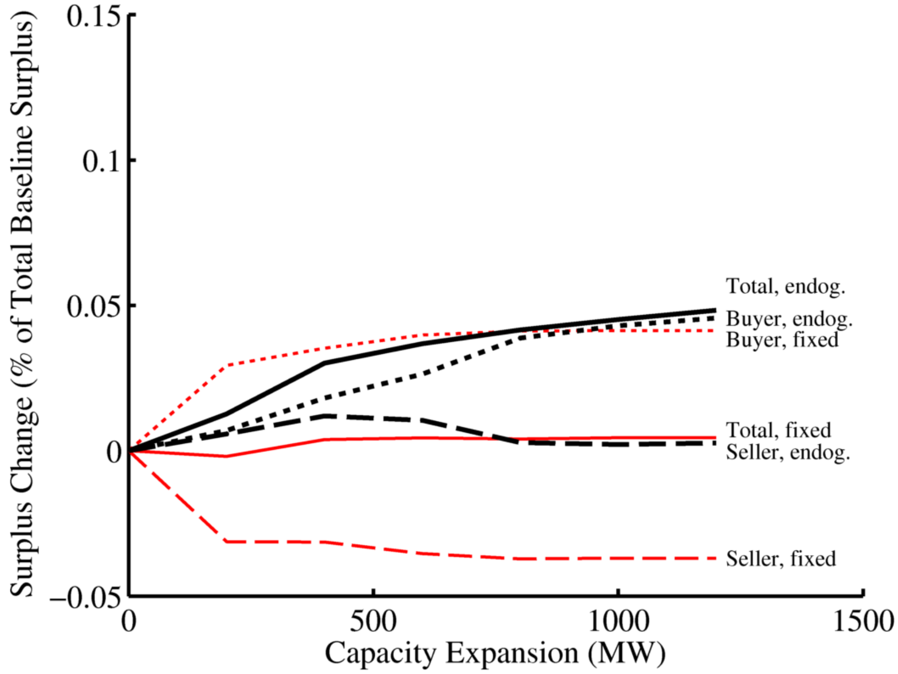
B. East to South, sample period



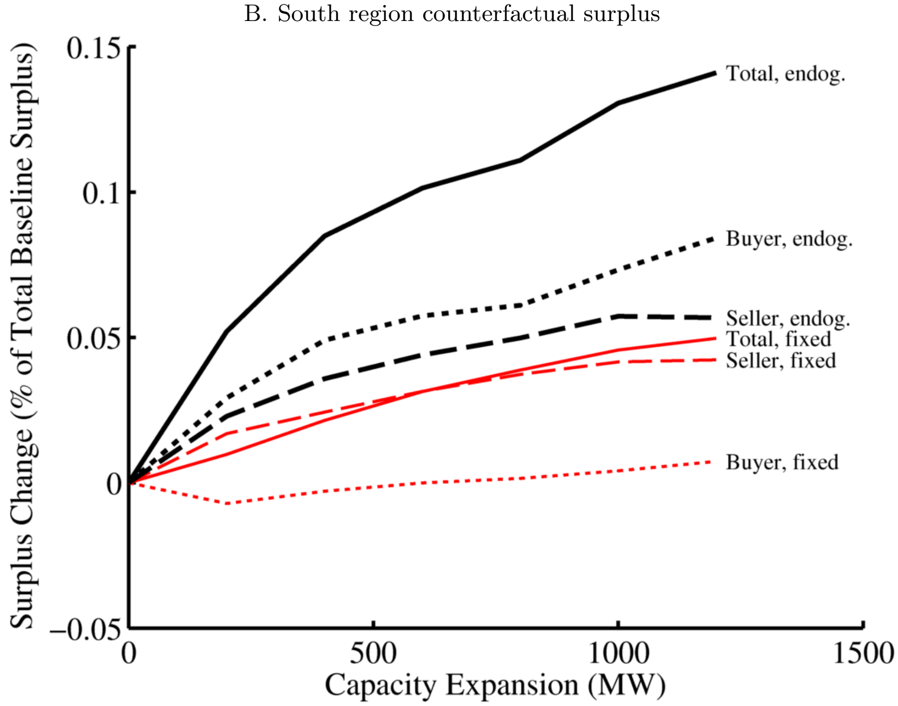
The figure plots the price difference between two regions against the power flow between two regions for the East to North and East to South corridors respectively. The price difference is the South or North price less the East price and the flow the net supply from the East region. A positive price difference implies that the flow is constrained.

Figure 6: Welfare with Relaxed Transmission Constraints

A. North region counterfactual surplus



B. South region counterfactual surplus



The figure shows changes in surplus for counterfactual increases of transmission capacity. Panel A shows expansions of capacity into the North regino and Panel B into the South region. In each panel, the thin (red) lines represent surplus holding strategic bids fixed at the baseline level while the thick (black) lines represent surplus allowing strategic bids to adjust endogenously to the new level of transmission constraints. Within each scenario, the dotted line represents buyer surplus (buyers are more numerous), the dashed line seller surplus and the solid line total surplus. 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 INR 1.41 billion (USD 28 million).

9 Tables

Table 1: Market and Bid Summary Statistics

	Mean (1)	Std. Dev. (2)	Min. (3)	Median (4)	Max. (5)	Obs. (6)
Unconstrained price	4352.90	2425.92	99.60	3999.61	13900.55	4344
Number of sell bids	24.70	6.04	12.00	25.00	54.00	4344
Number of buy bids	19.25	8.61	4.00	18.00	48.00	4344
Sell bid ticks	1.84	2.09	1.00	1.00	22.00	107304
Sell bid tick prices	3372.82	2263.49	25.50	3000.00	15000.00	107304
Sell bid tick quantities	33.73	67.47	0.25	9.10	1000.00	107304

Summary statistics for bidding on the Indian Energy Exchange from November, 2009 through April, 2010. Tick quantities are incremental quantities for that tick 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		744.6	384.6	279.9	100.9	618.2
East	5349.7					512.9
North	1768.7	1688.3		1703.6	1732.9	1685.4
South 1	1716.4	1655.5	1652.0			1646.9
South 2	1857.1	1808.5	1806.2	1310.0		1804.4
West	5349.7					

Summary statistics for congestion on the Indian Energy Exchange 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 INR 4352.90/MWh over the sample period.

Table 3: North Supply Response to Congestion

	Dependent variable: Bid Price			
	(1)	(2)	(3)	(4)
Panel A. Instrumental Variables Estimates				
North region import constrained	1745.5	1605.3***	747.9***	742.3***
at bid price	(2273.9)	(456.5)	(106.0)	(117.5)
Bid quantity	4.689		9.930***	
	(6.580)		(0.690)	
Bid quantity squared	-0.0124		-0.0257***	
	(0.0177)		(0.00220)	
Date effects	No	No	Yes	Yes
Bidder X Quantity Quadratic	No	Yes	No	Yes
Panel B. First-stage of Congestion on Corridor Allocation				
Short-term corridor allocation	-0.00464	-0.0173***	-0.0317***	-0.0314***
(100 MW)	(0.00587)	(0.00478)	(0.00408)	(0.00395)
N	239131	239131	239131	239131

All specifications include cubic controls for hour of day and a constant (columns 1 and 3) or set of bidder-specific constants (columns 2 and 4). All Panel B specifications include the covariates from Panel A. Standard errors clustered at the date level in parentheses with * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$. Sample of all supply bids submitted in the North region during the study period of November, 2009 through April, 2010. Each bid represented by price-quantity pairs where price is uniformly spaced from INR 2000 to INR 8000 / Mwh at INR 500 / MWh intervals and quantity is the quantity supplied at that price.

Table 4: Strategic Seller Characteristics and Estimated Marginal Costs

Region (1)	Type (2)	Share of Vol. Off. (%) (3)	Maximum Vol. Off. (MW) (4)	Wtd. Mean Tick Price (INR/MWh) (5)	Estimated Marginal Cost (INR/MWh) (6)	Std. Err. (INR/MWh) (7)
North	State Utility	2.29	700	4667.25	3762.63	(14.38)
North	Discom	7.67	1000	3020.56	2357.35	(13.39)
North	Discom	6.56	500	3669.74	2796.59	(9.81)
North	Discom	1.07	475	4377.05	4108.53	(14.04)
West	State Utility	22.73	400	3659.81	3084.47	(21.96)
West	State Utility	10.90	250	2423.10	1836.23	(2.56)
West	State Utility	2.52	250	4565.90	4026.16	(15.68)
West	Private Genco	8.06	480	1799.12	963.49	(23.57)
West	Private Genco	3.83	65	3342.75	2917.50	(2.97)
West	Industrial Plant	1.46	44	5498.90	3098.82	(57.02)
West	Industrial Plant	1.36	36	6619.72	5923.74	(60.68)
West	Industrial Plant	1.22	250	1828.40	2264.50	(9.92)
West	Industrial Plant	1.03	198	745.06	680.45	(35.06)

Statistics for bidding by strategic sellers on the Indian Energy Exchange 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 3 **??**. Standard errors are bootstrapped by resampling 100 bootstrap iterations with replacement from the set of moment conditions. 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 5: Model Fit

	Actual		Model	
	Mean	Std Dev	Mean	Std Dev
	(1)	(2)	(3)	(4)
	Unconstrained			
Clearing price (INR/MWh)	4352.90	2425.92	3687.16	1692.78
Clearing quantity (MW)	936.82	328.64	1256.42	525.75
	North region			
Clearing price (INR/MWh)	4342.68	2426.17	3803.48	1745.70
Price > West price (% of hrs)	0.18	0.39	0.16	0.37
Price - West Price (if not equal)	1685.38	1091.98	1437.39	984.88
Net demand (MW)	258.45	244.49	323.59	269.22
	South 1 region			
Clearing rice (INR/MWh)	4419.46	2559.79	4246.17	2257.18
Price > West price (% of hrs)	0.23	0.42	0.33	0.47
Price - West Price (if not equal)	1646.88	1228.94	2049.47	1291.42
Net demand (MW)	-81.10	180.84	-78.51	186.34
	West region			
Price (INR/MWh)	4035.79	2403.17	3664.31	1814.86
Net demand (MW)	-346.12	247.01	-445.20	304.21

The table shows the fit of the constrained Cournot model to market outcomes on the Indian Energy Exchange from November, 2009 through April, 2010.

Table 6: Market Outcomes with Relaxed Transmission Constraints

Expansion relative to baseline	0 MW (1)	400 MW (2)	800 MW (3)	1200 MW (4)
Panel A. North region capacity expansion				
Strategic Bids Fixed at Baseline				
North price > West Price (% of hrs)	0.16	0.02	0.00	0.00
North price - West Price (INR/MWh)	1437.39	1060.98	1908.08	2425.83
North net demand (MW)	323.59	347.90	351.78	351.86
West net demand (MW)	-445.20	-443.51	-445.24	-445.26
Market surplus (INR m / hr)	3.26	3.28	3.28	3.28
Market buyer surplus (INR m / hr)	1.15	1.26	1.28	1.28
Market seller surplus (INR m / hr)	2.12	2.02	2.00	2.00
Strategic Bids Endogenous				
North price > West Price (% of hrs)	0.16	0.07	0.02	0.00
North price - West Price (INR/MWh)	1437.39	1244.06	1148.09	1381.43
North net demand (MW)	323.59	381.03	401.61	407.14
West net demand (MW)	-445.20	-491.19	-509.65	-514.69
Market surplus (INR m / hr)	3.26	3.36	3.40	3.42
Market buyer surplus (INR m / hr)	1.15	1.21	1.27	1.30
Market seller surplus (INR m / hr)	2.12	2.16	2.13	2.13
Panel B. South region capacity expansion				
Strategic Bids Fixed at Baseline				
South 1 price > West Price (% of hrs)	0.33	0.08	0.03	0.00
South 1 price - West Price (INR/MWh)	2049.47	1509.93	1377.20	1734.89
South 1 net demand (MW)	-78.51	-40.65	-22.60	-18.59
West net demand (MW)	-445.20	-448.87	-450.44	-451.00
Market surplus (INR m / hr)	3.26	3.33	3.39	3.43
Market buyer surplus (INR m / hr)	1.15	1.14	1.15	1.17
Market seller surplus (INR m / hr)	2.12	2.20	2.24	2.26
Strategic Bids Endogenous				
South 1 price > West Price (% of hrs)	0.33	0.10	0.06	0.01
South 1 price - West Price (INR/MWh)	2049.47	1652.88	1524.84	1133.65
South 1 net demand (MW)	-78.51	-24.11	10.42	24.40
West net demand (MW)	-445.20	-492.39	-507.59	-512.25
Market surplus (INR m / hr)	3.26	3.54	3.63	3.73
Market buyer surplus (INR m / hr)	1.15	1.31	1.35	1.42
Market seller surplus (INR m / hr)	2.12	2.23	2.28	2.30

The table shows the fit of the constrained Cournot model to market outcomes on the Indian Energy Exchange from November, 2009 through April, 2010.

Table 7: 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

10 Appendix

(a) Discretization of Single Bids

The Indian Energy Exchange allows bids to be piecewise-linear functions from pirce 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, 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 7 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 INR 250/MWh intervals, such that the average quantity supplied over the segment is the same as in the original bid.

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, 2011; Hortacsu and Puller, 2008). The presence of two power exchanges may make the second factor more important in India. The Power Exchange India Limited (PXI) restricts bids to be step functions so bidders may prefer to submit nearly the same bid on both rather than making use of the allowed linearity on the Indian Energy Exchange (IEX).

(b) 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, 2011). 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:

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

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.[33]

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 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

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

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% 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 in aggregate are still an important 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 et al. (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 similar to Reguant (2011) 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.

(c) Market-splitting Algorithm

The algorithm for identifying binding transmission constraints is 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.

(d) 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 8: Area-Clearing Price Differences

Quarter	Unconstrained Clearance Hours (1)	Mean Price (2)	Abs Diff (3)	Pct Diff (4)	Constrained Clearance Hours (5)	Mean Price (6)	Abs Diff (7)	Pct Diff (8)
200901	2160	6199.33	6.10	0.10	34	6029.18	3.12	0.36
200902	2184	7771.64	14.91	0.19	776	5314.09	41.78	1.44
200903	2208	5326.42	8.13	0.15	1192	4313.33	73.58	2.40
200904	2208	3494.80	3.53	0.10	491	3576.61	108.45	3.78
201001	2160	4108.02	6.38	0.16	1269	4368.14	69.84	2.11
201002	2184	5300.93	7.36	0.14	420	5981.81	50.74	0.91
201003	2208	3067.02	4.22	0.14	174	3293.08	7.60	0.23
201004	2208	2345.78	2.63	0.11	934	2860.87	56.23	1.96
201101	2160	3564.59	1.84	0.05	1695	4848.80	31.61	0.41

Table 8 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 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 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.

(e) 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 9 shows moments of the actual and simulated price distribution for the Uncon-

Table 9: Accuracy of Prices Simulated by Bootstrap

	Unconstrained		North		West	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
Mean	4352.90	4369.35	4342.68	4295.72	4035.79	3964.92
Std	2425.92	2422.03	2426.17	2418.23	2403.17	2413.26
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	99.60	0.00	99.60	0.00	99.60	0.00
p10	1501.70	1502.00	1501.70	1501.00	1500.86	1500.00
p25	2600.47	2601.00	2500.32	2501.00	2499.35	2480.00
p50	3999.61	4000.00	4000.42	4000.00	3400.34	3290.00
p75	5501.51	5751.00	5500.30	5502.00	4999.35	5000.00
p90	8000.52	7950.00	8001.16	7998.00	8000.31	7801.00
Max	13900.55	14768.00	13900.55	18001.00	13900.55	20000.00

strained, North and West prices, respectively. The means and standard deviations of the 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.

(f) 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 in the manner of Wolak (2007). 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:

$$\begin{aligned}\tilde{D}^{rg}_{it}(p|\sigma_{-i},\mathcal{L}) &= D^{g}(0,\sigma_{-it}) - \sum_{j\neq i, j\in\mathcal{A}_g}\sum_{k} q_{jk}\Phi\left(\frac{p-p_{jk}}{w}\right)\\ \frac{\partial\tilde{D}^{rg}_{it}(p|\sigma^{\mathbf{s}}{}_{-i},\mathcal{L})}{\partial p} &= -\frac{1}{w}\sum_{j\neq i, j\in\mathcal{A}_g}\sum_{k} q_{jk}\phi\left(\frac{p-p_{jk}}{w}\right).\end{aligned}$$

The bandwidth w controls the degree of smoothing, with a larger bandwidth smoothing the curve more. I set w = INR 500/MWh in the estimation. Own-supply is smoothed in a similar manner. Following Wolak (2007), 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.

The counterfactual simulation involves strategic sellers maximizing profits with respect to quantity. The conditions for profit maximization therefore depend on the first and second derivatives of inverse residual demand with respect to quantity. I represent inverse residual demand as a set of whole quantities and incremental prices and smooth over quantities, in a manner exactly analagous to the above smoothing over prices, 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.