Empirical Methods for the Analysis of the Energy Transition

Slide Set 2

Prof. Mar Reguant

Fall 2024
IDEA

Northwestern

Outline

I. The Economics of Electricity Markets
  Overview of functioning

II. Empirical analysis of electricity market performance
  Borenstein, Bushnell, and Wolak (2002)
  Bushnell, Mansur, and Saravia (2008)

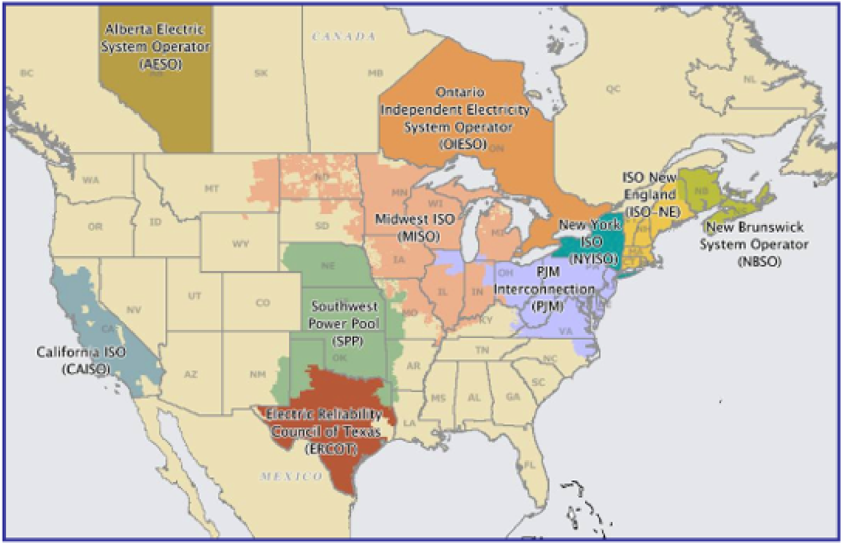
III. Extension to sequential markets
  Ito and Reguant (2016)

I. The Economics of Electricity Markets

Dispatching electricity markets

- Basic structure is typically designed around a wholesale market for electricity.
- Generators submit bids for electricity every day!
  - The complexity of these bids varies significantly across markets
    - Bid just one price for energy vs. include start up costs.
    - Have separate products for capacity and energy vs. only energy.
    - Etc.
- Demand also submits bids for electricity
  - Can be sloped or not
- Lots of other details that we will discuss
  - Price caps, "capacity markets", etc.

US liberalized markets

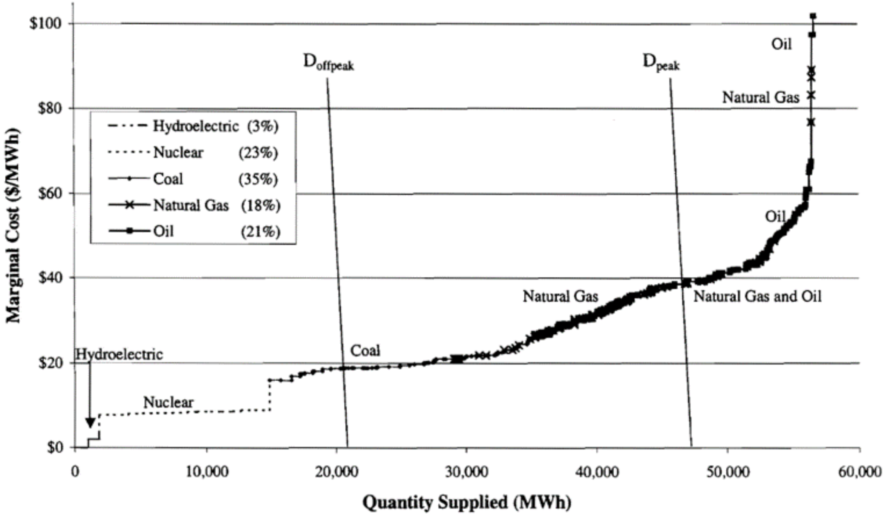


An example: bidding in Chicago

- Imagine a power company in Chicago.
- It will offer its power on a *daily basis* to the PJM market.
  - The typical offer will consist of several price-quantity offers for every hour of the day.
  - Example: at 8 am, the firm is willing to produce 200 MWh as long as the price is at least \$45/MWh with one of their plants.
- Many other companies will also offer their power at the PJM market.
- The system operator will collect all the bids from all the power plants.
- It will then cross supply with demand and determine the marginal price that all accepted units get.

A supply example for PJM

Figure 2. Competitive supply and demand in Pennsylvania–New Jersey–Maryland (PJM)



What do the bids represent?

- If the market is very competitive, the bids will tend to represent the **marginal cost of a given firm**.
- If there is market power, then firms might bid above their marginal cost, to increase prices.
- For the case of hydro power, bids will tend to represent the opportunity cost of water.
  - Note: the opportunity cost of water can be quite high for markets with limited hydro availability or during scarcity conditions (droughts).
- For renewables, bids will tend to be quite low or reflect market power considerations.

What about demand?

- Demand also participates in the market, although it is typically quite inelastic.
  - Final consumers do not directly demand power: the distribution utilities or retailers do it on their behalf.
- Big industrial consumers or commercial customers might participate in the market, and avoid consuming electricity if prices are too high.
  - Much more elastic, extensive contracting that may require firms to respond in moments of high prices.
  - Some big industrial producers participate directly as generators (co-generators, direct generation).

Nodal vs. zonal markets

- The crossing of demand and supply may or may not account for bottlenecks in the electricity grid.
  - Nodal markets: Typical in the US, each node in the grid has its own price (thousands of different marginal prices every hour).
  - Zonal markets: Typical in Europe, large areas all share the same price, e.g., Spain, Portugal, four regions in Germany, etc.

- Several studies have highlighted the advantages of having more granular prices (Green, 2007; Joskow 2008; Holmberg and Lazarczyk, 2015; Graf et al., 2020).

Day-ahead vs. real-time markets

- The crossing of demand and supply may happen at different points in time.
  - Day-ahead markets: A few hours in advance, a preliminary schedule of what will happen (most commonly with a financial committment).
  - Real-time markets: A few minutes before the dispatch happens (e.g., 5 to 30 min).
- In many areas, consumers pay the day-ahead price (or a forward price that uses the day-ahead as reference).
- Therefore, a lot of focus goes into day-ahead markets, which clear the most volume.
- After the real-time market, last-minute adjustments are handled with automatic decisions (but still receive compensation ex-post).

In practice, much more complex

- As we discussed, demand and supply need to balance at all time.
- Electricity markets tend to have a day-ahead auction to plan in advance.
  - Tends to clear the largest economic volume.
- But there are many follow up markets and products to ensure balance in real time.
  - Very complicated, and often market-specific!
  - Some of these markets are related to congestion.
- Electricity operators solve complex problems every hour/half-hour to determine the dispatch allocation over a wide-range of products (energy, reserves, transmission rights, etc.).

Modeling economics in electricity markets

- At its heart, all electricity market models have firms/technologies and information about demand (as a curve or fixed) to find the best allocation that ensures demand = supply (called economic dispatch).
- If the model takes into account discrete decisions about which power plants to turn on/off, it is called a unit committment problem (more difficult to solve).

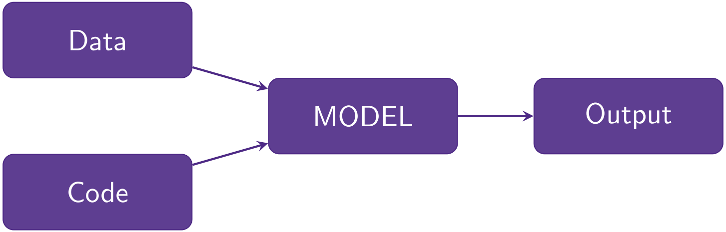
- Depending on the question at hand, the electricity markets in economic analysis are modeled abstracting away from many features.
- E.g., big long-run policy questions like climate policy might be answered with a simplified version of the market.

- Depending on the question, some more detailed features need to be brought back (e.g., transmission congestion regarding renewable expansion).

Market power modeling

- Strategic players compete in quantities while taking the competitive supply curve and imports as given.
- Alternative representations are models of supply function equilibria (SFE) and models of conjectural variations, also agent-based formulations not uncommon in electrical engineering.
- The Cournot formulation is best for counterfactual modeling (in my opinion and experience). We will see today that it can be formulated as a set of first-order conditions.

Building models of electricity markets



- Model used to simulate impact of alternative configurations, profitability of investments, impacts of climate policies, etc.
- Does output for baseline match data? If not, do we need to expand code?
  - Not always, keep an eye on things that are important to our question and that we might not be matching well. A <u>model is a simplification of a complex reality.</u>

Building models of electricity markets

Common elements and options

- Supply side
  - Competitive (cost curves) or strategic (firms max profit, eq. concept)
  - At tech, firm, or plant level
  - With or without geography (transmission, usually with direct current approximation)
  - With or without startup costs (non-convexities)
- Demand side
  - Inelastic or responsive
  - Granular or aggregated

Horizon and temporal linkages

- Level of aggregation
  - Hourly, daily, etc.
- Links between hours
  - Every hour independent from each other vs. temporal linkages (important for storage or startup costs)
- Horizon of choice
  - Day-to-day operations
  - Seasonal water storage
  - Capacity expansion model (investment)

II. Empirical analysis of electricity market performance

Outline

I. The Economics of Electricity Markets
Overview of functioning

II. Empirical analysis of electricity market performance
Borenstein, Bushnell, and Wolak (2002)
Bushnell, Mansur, and Saravia (2008)

III. Extension to sequential markets
Ito and Reguant (2016)

Concerns over the performance of electricity markets

- Recent high energy prices have resurfaced concerns about the performance of electricity markets:
  - Are they competitive?
  - Are they *fair*?
  - Do they have an appropriate design?
  - Is marginal pricing justified?

- A key question is to which extent firms behave as economic agents through the lens of stylized models, which can be used to benchmark competition levels.

Economics tools to analyze market performance

- Theoretical models of market design
- Empirical analysis of previous market performance
- Simulation models to examine counterfactuals (alternative market rules, configurations, input costs, etc.)

Empirical analysis of electricity markets

- Large literature has used electricity models to analyze the **performance of electricity markets**.
- Literature explorations:
  - How do market outcomes compare to an idealized operation of the market?
  - How do market outcomes compare to an economic model of behavior?
  - How do bidding outcomes compare to an auction model of behavior?
- I will discuss **two seminal papers** that use different approaches to modeling firm behavior (competitive vs. strategic).

Market power in electricity markets

- Market performance in deregulated wholesale markets
  - Wolfram (1999), Borenstein, Bushnell, and Wolak (2002), Wolak (2007)
- Measurements of incentives and ability to exercise market power (markup components)
  - Wolfram (1998), McRae and Wolak (2012)
- Vertical integration and market performance
  - Mansur (2007), Bushnell, Mansur, and Saravia (2008)
- Auction design in wholesale electricity markets
  - Wolak (2000, 2003) , Hortacsu and Puller (2008), Reguant (2014)
- Market power in sequential electricity markets
  - Ito and Reguant (2016), Fabra and Imelda (2021)

Borenstein, Bushnell, and Wolak (2002)

Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market

By Severin Borenstein, James B. Bushnell, and Frank A. Wolak*

We present a method for decomposing wholesale electricity payments into production costs, inframarginal competitive rents, and payments resulting from the exercise of market power. Using data from June 1998 to October 2000 in California, we find significant departures from competitive pricing during the high-demand summer months and near-competitive pricing during the lower-demand months of the first two years. In summer 2000, wholesale electricity expenditures were $8.98 billion up from $2.04 billion in summer 1999. We find that 21 percent of this increase was due to production costs, 20 percent to competitive rents, and 59 percent to market power. (*JEL* L1, L9)

Summary of Borenstein, Bushnell, and Wolak (2002)

- **What does the paper do?**
  1. Empirically estimate the marginal cost of production
  2. Construct a (counterfactual) competitive market price
  3. Compare it to actual market outcomes to measure market inefficiency
- **What does the paper find?**
  - Wholesale electricity expenditures in the summer of 2001 = \$8.98 billion (it was \$2.04 billion in 1999)
  - 21% of this increase was due to production costs
  - 20% to competitive rents
  - 59% to market power

Data

- Hourly price and quantity data at Power Exchange (PX) day-ahead market from 1998-1998, settlement ISO data.
- Estimates of heat rates by power plant, O&M, pollution costs (NO_x), from the California Energy Commission.
- Spot gas prices times heat rate determines cost.
- Outages/unavailabilities from NERC.

Market Structure

Table 1—California ISO Generation Companies (MW)

July 1998—online capacity				
Firm	Fossil	Hydro	Nuclear	Renewable
AES	4,071	0	0	0
Duke	2,257	0	0	0
Dynegy	1,999	0	0	0
PG&E	4,004	3,878	2,160	793
Reliant	3,531	0	0	0
SCE	0	1,164	1,720	0
SDG&E	1,550	0	430	0
Other	6,617	5,620	0	4,267
July 1999—online capacity				
Firm	Fossil	Hydro	Nuclear	Renewable
AES	4,071	0	0	0
Duke	2,950	0	0	0
Dynegy	2,856	0	0	0
PG&E	580	3,878	2,160	793
Reliant	3,531	0	0	0
SCE	0	1,164	1,720	0
Mirant	3,424	0	0	0
Other	6,617	5,620	430	4,888

Source: California Energy Commission (www.energy.ca.gov).

Methodology

1. Cost estimation
   - Based on engineering estimates
   - Need to deal with water (complicated dynamic program, simplify with "peak shaving") and "must-take" (fixed)
   - Need to estimate import supply elasticity
   - Montecarlo to control for outages, maintenance
2. Counterfactual
   - Construct marginal cost curves using above assumptions
   - Competitive equilibrium as $P = MC$.
3. Market power
   - Compare observed prices to competitive prices

Comparison to the IO literature

Similarities

- Markup calculation as the residual from marginal cost, $\mathrm{P} = \mathrm{MC} + \mathrm{Markup}$

Differences

- Marginal cost not estimated, taken from engineering estimates
- Does not consider a strategic model of competition, more "non-parametric"
- Drawback: strong assumptions behind interpretation

Weighted Markups

- **Lerner Index**

$$\text{Markup} = \frac{P - MC}{P}$$

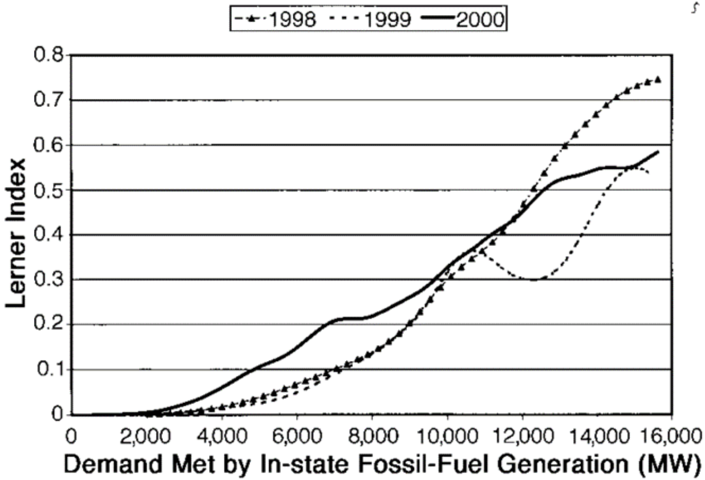
- In this setting:

$$\text{Markup} = \frac{P_{observed} - P_{competitive}}{P_{observed}}$$

- Note: Paper weights each price with quantities, more weight when total quantity is larger (after taking away "must take", which they hold fixed).

Markups increase as a function of production

Markups higher during the events of 2000



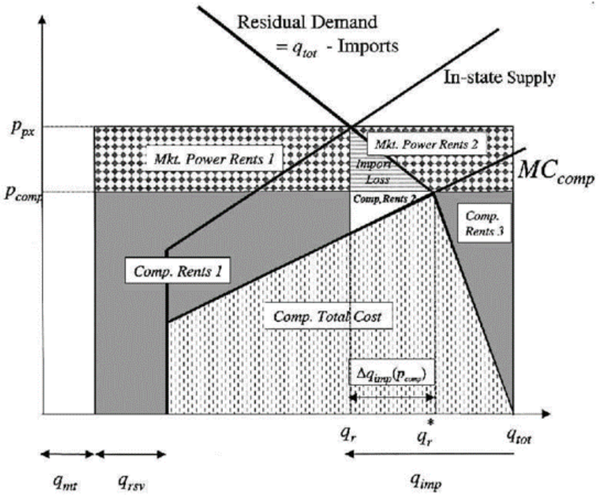
Rent division

Total wholesale market payment can be divided into the three types:

- Production costs
  - Even holding quantity fixed, potentially larger under oligopoly, specially with asymmetric firms (e.g., see Mansur 2008)
- Infra-marginal competitive rent
- Rents due to market power (higher prices)

Important to understand the difference between the three types of costs

Decomposition of expenditure



Decomposition of expenditure

Table 3—Production Costs and Rent Distribution ($ Million) June–October

	1998	1999	2000
Total actual payments	1,672	2,041	8,977
Total competitive payments	1,247	1,659	4,529
Production costs—actual	759	1,006	2,774
Production costs—competitive	715	950	2,428
Competitive rents	532	708	2,101
Oligopoly rents	425	382	4,448
Oligopoly inefficiency—in state	31	31	126
Oligopoly inefficiency—imports	13	24	221

Bushnell, Mansur, and Saravia (2008)

Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured US Electricity Markets

By JAMES B. BUSHNELL, ERIN T. MANSUR, AND CELESTE SARAVIA*

This paper examines vertical arrangements in electricity markets. Vertically integrated wholesalers, or those with long-term contracts, have less incentive to raise wholesale prices when retail prices are determined beforehand. For three restructured markets, we simulate prices that define bounds on static oligopoly equilibria. Our findings suggest that vertical arrangements dramatically affect estimated market outcomes. Had regulators impeded vertical arrangements (as in California), our simulations imply vastly higher prices than observed and production inefficiencies costing over 45 percent of those production costs with vertical arrangements. We conclude that horizontal market structure accurately predicts market performance only when accounting for vertical structure. (*JEL* L11, L13, L94)

Bushnell, Mansur, and Saravia (2008)

What does the paper do?

- Compare market performance in three US wholesale electricity markets using strategic models
  - California
  - New England
  - PJM (Pennsylvania, New Jersey, and Maryland)
- Examine which of three models fit actual market outcomes best
  - Perfect competition
  - Cournot oligopoly
  - Cournot oligopoly with vertical integration
- Analyze how the **vertical integration** of retail and wholesale parts affect the competitiveness of wholesale electricity markets

Motivation: Why California?

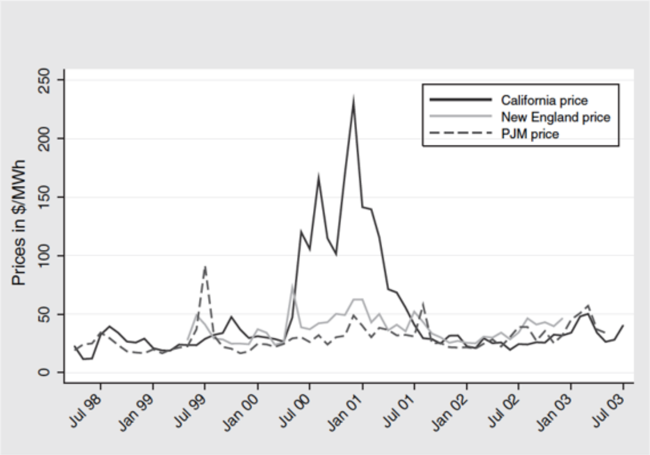


FIGURE 1. PRICE PATH IN ALL MARKETS
(*California, New England, and PJM Monthly Averages*)

Comparison across the three markets

	California	New England	PJM
When did transactions start?	April, 1998	May, 1999	April, 1999
Who controls transmission lines?	California ISO (CAISO)	New England ISO (ISONE)	PJM Interconnection
Output max summer 1999 (GWh)	44.1	25.7	56.7
Load max summer 1999 (GWh)	45.9	22.3	51.7
Horizontal market concentration (HH)	620	850	1400
Import	25%	10%	little

Vertical Integration after deregulation

- **PJM**
  - Retailers retained their generation assets
  - In other words, retailers and wholesalers were vertically integrated
- **New England**
  - Divestitures of generation from vertically integrated utilities
  - However, retail utilities signed long-term supply contracts with wholesalers
  - Retailers signed contracts with the wholesaler that they previously owned
- **California**
  - No meaningful long-term contracts
  - Most electricity was sold in the pool spot market
  - Large utilities still owned some generating plants in 1999, but they were low marginal cost capacity (nuclear and hydro)

Vertical Integration and market power

Vertical integration in the three markets

- *PJM and New England:* vertically integrated or long-term contracts between retailers and wholesalers
- *California:* almost no vertical integration for high marginal cost plants

Hypothesis

- Vertically integrated firms have LESS incentives to raise wholesale prices
- This is because integrated firms make retail price commitments before committing production to their wholesale market
- On the other hand, non-integrated wholesalers have larger incentives to raise wholesale prices because they do not need to care about retail prices

Vertical arrangements in a Cournot setting

Assume profit maximizing firms

$$\pi_{i,t}(q_{i,t}, q^r_{i,t}) = p^w_t(q_{i,t}, q_{-i,t}) \cdot [q_{i,t} - q^r_{i,t}] + p^r_{i,t}(q^r_{i,t}, q^r_{-i,t}) \cdot q^r_{i,t} - C(q_{i,t})$$

Implied first order condition

$$\frac{\partial \pi_{i,t}}{\partial q_{i,t}} = p^w_t(q_{i,t}, q_{-i,t}) + [q_{i,t} - q^r_{i,t}] \cdot \frac{\partial p^w_t}{\partial q_{i,t}} - C'_{i,t}(q_{i,t}) \geq 0$$

- Key is that q^r and p^r are considered sunk at this stage.
- Firms only care about the impact of marginal price increases on the net day-ahead market quantity.
- For competitive, assume no markup term.

Note: Paper shows equilibrium can be solved as a complementarity problem (this will be part of the model building exercise).

Data

- PJM, New England and California data.
- Similar cost data to BBW (California), Saravia (2003) for New England, and Mansur (2007) for PJM.
- Important addition with vertical arrangements and long-term contracts.
  - Vertical position inferred for vertically integrated firms
  - Publicly available data on long-term contracts for PJM and New England
  - No data for California on long-term contracts, but by construction there were limited

Results: All Hours

Variable	Mean	Median
Panel A: Peak hours (11 am to 8 pm weekdays)		
California actual	43.15	34.52
Competitive	35.01	30.88
Cournot	45.17	40.19
New England actual	55.05	33.16
Competitive	41.72	35.04
Cournot	54.63	40.44
Cournot n.v.a.	280.47	145.86
PJM actual	97.31	33.17
Competitive	35.08	33.27
Cournot	87.05	36.00
Cournot n.v.a.	1,000.00	1,000.00

- Cournot setting much better at replicating observed prices than Competitive setting
- Vertical arrangement crucial (see substantially higher prices for n.v.a rows)

Very nice fit across all markets

Calefornia

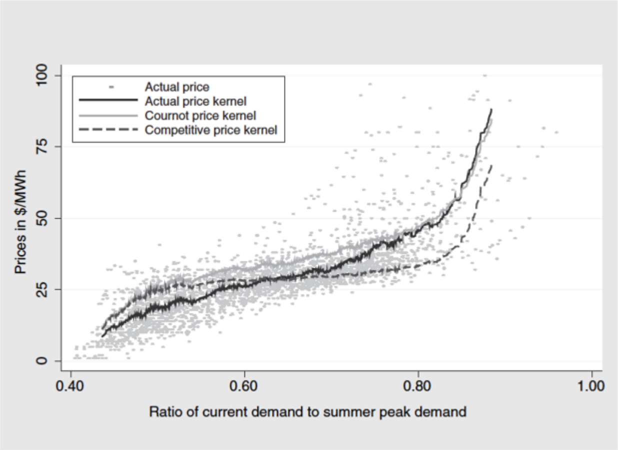


FIGURE 2. PRICES BY QUANTITY DEMANDED IN CALIFORNIA
(Actual, competitive, and Cournot price kernels)

Very nice fit across all markets

New England

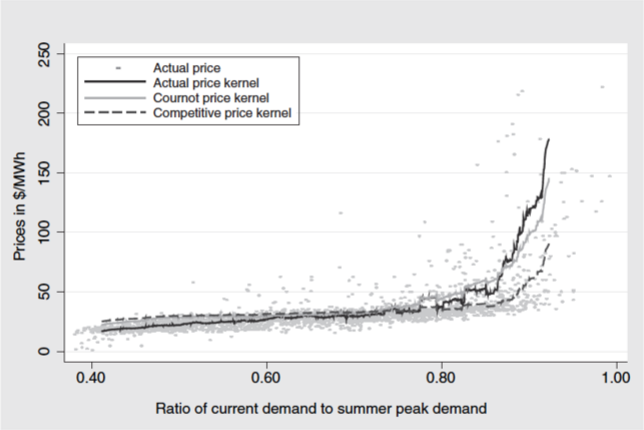


FIGURE 5. VERTICAL ARRANGEMENTS IN NEW ENGLAND
(Actual, competitive, and Cournot price kernels)

Very nice fit across all markets

PJM

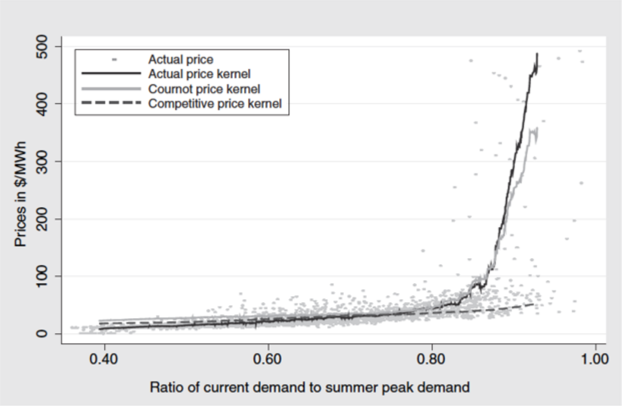


FIGURE 6. VERTICAL ARRANGEMENTS IN PJM
(Actual, competitive, and Cournot price kernels)

Comparison Across Hours

Variable	Mean	Median
Panel A: Peak hours (11 am to 8 pm weekdays)		
California actual	43.15	34.52
Competitive	35.01	30.88
Cournot	45.17	40.19
New England actual	55.05	33.16
Competitive	41.72	
Cournot	54.63	
Cournot n.v.a.	280.47	
PJM actual	97.31	
Competitive	35.08	
Cournot	87.05	
Cournot n.v.a.	1,000.00	
Panel B: Off-peak hours		
California actual	23.90	24.99
Competitive	26.10	27.44
Cournot	30.00	31.25
New England actual	29.18	26.61
Competitive	31.73	31.14
Cournot	32.63	30.54
Cournot n.v.a.	86.16	55.82
PJM actual	23.84	18.10
Competitive	25.42	23.78
Cournot	32.73	30.00
Cournot n.v.a.	900.57	1,000.00

Check Reguant (2014)
for a correction on markups

Potential biases due to
dynamic costs of operation

Summary of Bushnell, Mansur, and Saravia (2008)

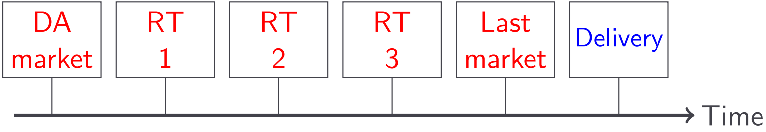
- Vertical arrangements are of crucial importance to explain firm behavior
- When vertical arrangements are accounted for, Cournot model gives a good fit to the data
  - Ideally, SFE. But not as tractable.
- Other work has been using the BMS framework to look at other questions.
  - E.g., Ito and Reguant (2014).

III. Extension to sequential markets

- In most of the IO/energy literature, focus of study is a single market (day-ahead or real-time).
- Most models do not consider sequential nature of markets.
- However, data on several sequential markets can provide useful information:
  - Sequential markets provide observable forward contracts, as they tend to financially settle.
  - Sequential markets can generate strategic incentives.

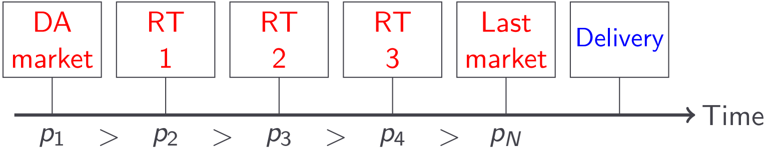
Example of Sequential Markets: Electricity Markets

- Electricity is first allocated in a centralized fashion in the day-ahead market.
- Subsequent markets open to re-allocate production and re-optimize hourly plans.
- Supply and demand need to be balanced at the delivery.



Price Differences in Sequential Markets

- In a stylized setting, price differences should go away
- However, empirically, we do not see it in many markets
- Most electricity markets exhibit systematic price differences
  - PJM, NY, New England, Midwest, CA, Iberian etc.



Sequential Markets Literature

- Lazear (1986); Allaz and Vila (1993); Salant (2011); Coutinho (2013).
- Saravia (2003); Borenstein, Bushnell, Knittel and Wolfram (2008); Jha and Wolak (2013); Birge, Hortacsu et al. (2013).
- Ito and Reguant (2016), Fabra and Imelda (2021).
- Bergheimer, Cantillon, and Reguant (2023, work in progress).

Ito and Reguant (2016)

Sequential Markets, Market Power and Arbitrage*

Koichiro Ito
University of Chicago and NBER

Mar Reguant
Northwestern University and NBER

December 16, 2015

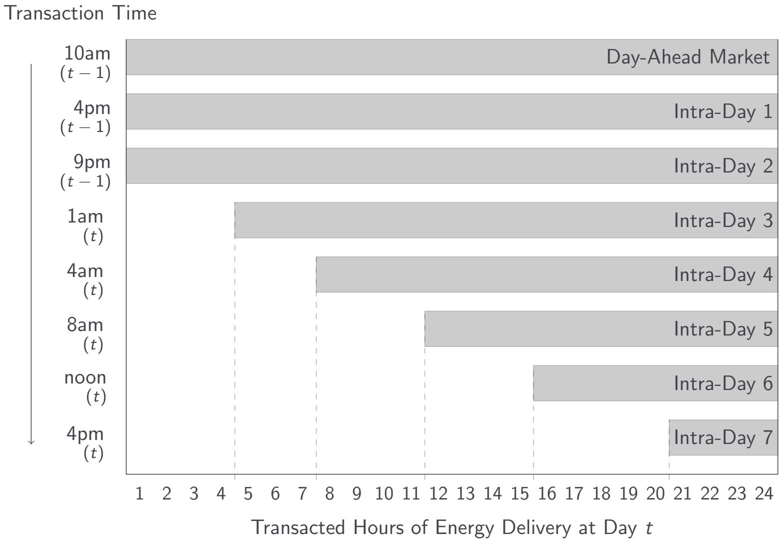
Abstract

We develop a framework to characterize strategic behavior in sequential markets under imperfect competition and restricted entry in arbitrage. Our theory predicts that these two elements can generate a systematic price premium. We test the model predictions using micro-data from the Iberian electricity market. We show that the observed price differences and firm behavior are consistent with the model. Finally, we quantify the welfare effects of arbitrage using a structural model. In the presence of market power, we show that full arbitrage is not necessarily welfare-enhancing, reducing consumer costs but increasing deadweight loss.

Research question 1) What drives price differences in sequential markets?

- An important policy question for market design
  - Equalizing market prices is often interpreted as efficiency
- **Theory:** We show how market power and limits on arbitrage can generate systematic price differences (declining prices).
  - $p_1 > p_2 > \cdots > p_N$.
  - Mimics dynamic monopoly pricing.
- **Empirics:** We examine firms' strategic behavior by using data from the Iberian electricity market
  - Hourly bids and production data at the power plant unit level
  - We also exploit the unique market structure

Sequential Markets in the Iberian Market



Research question 2) What are the welfare implications of arbitrage under imperfect competition?

- Equalization of expected forward and spot prices is often interpreted as a sign of efficiency.
  - Under certain conditions, in an efficient market prices equalize.
- **Theory:** Under imperfect competition, **even** if prices equalize, they might not converge to their competitive level.
- Moreover, full arbitrage is not necessarily welfare enhancing
  - True even if the transaction costs of arbitrage are zero
- **Empirics:** We use welfare counterfactual analysis to show it

A Model of Sequential Markets

- Consider two sequential markets.
- Consider a large supplier with cost c.
- All energy is allocated in the first market (day-ahead).
- The second market is for re-shuffling (real-time).
- Residual monopolist faces demands,

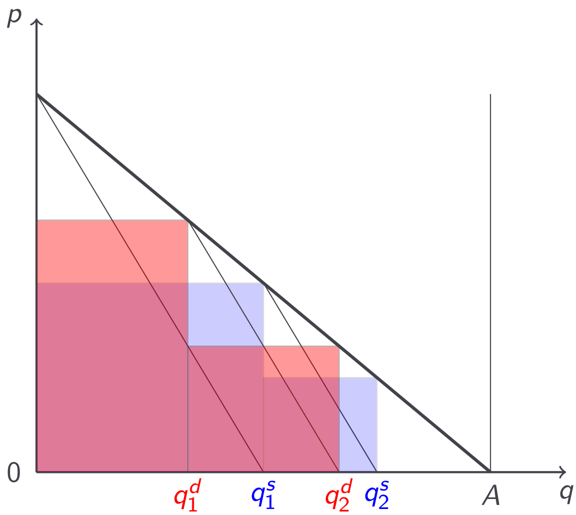
$$D_1(p_1) = A - b_1 p_1, \quad D_2(p_1, p_2) = b_2(p_1 - p_2).$$

Interpretation of Residual Demand

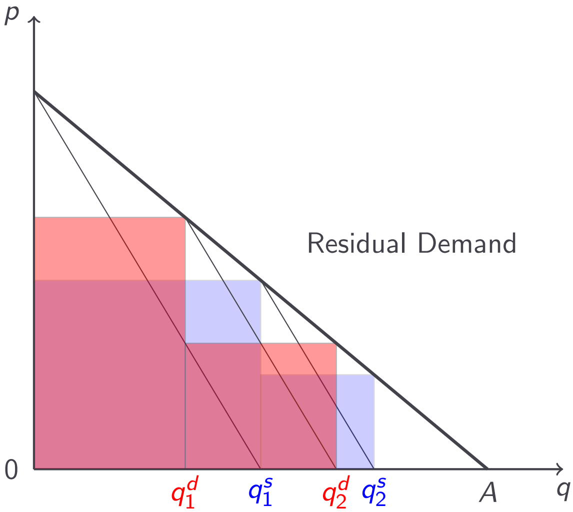
$$D_1(p_1) = A - b_1 p_1, \quad D_2(p_1, p_2) = b_2(p_1 - p_2).$$

- Residual demand at day-ahead can be interpreted as inelastic demand A minus supply curve by other firms, $b_1 p_1$.
- Interpret $b_1 p_1$ as fringe suppliers pricing at marginal cost.
- In second market, production can re-adjust along the marginal cost curve.
- Note: typically, real-time market less responsive, $b_2 < b_1$.

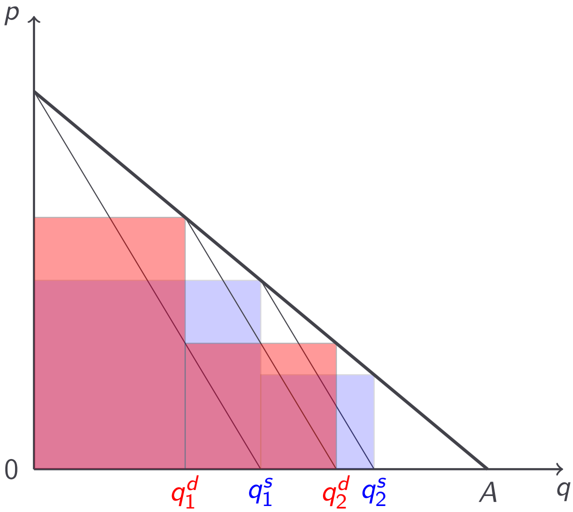
Intuition as Dynamic Monopolist, $b_1 = b_2$



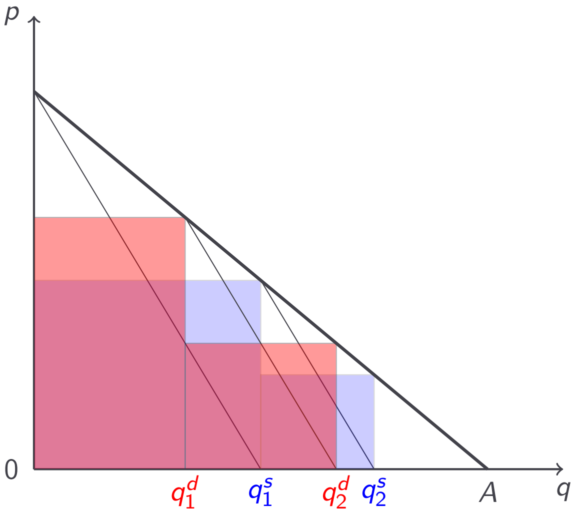
Intuition as Dynamic Monopolist, $b_1 = b_2$



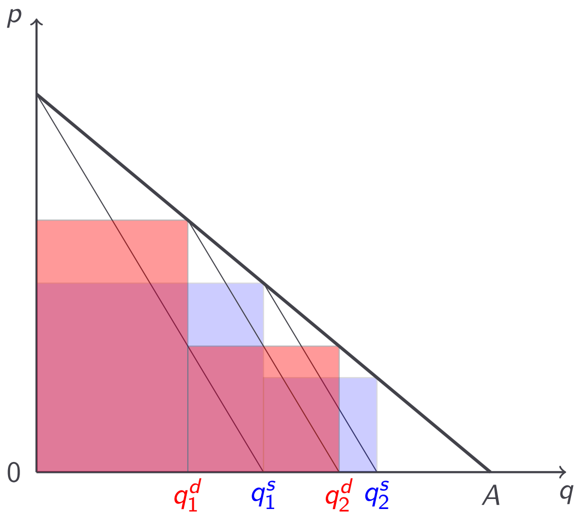
Intuition as Dynamic Monopolist, $b_1 = b_2$



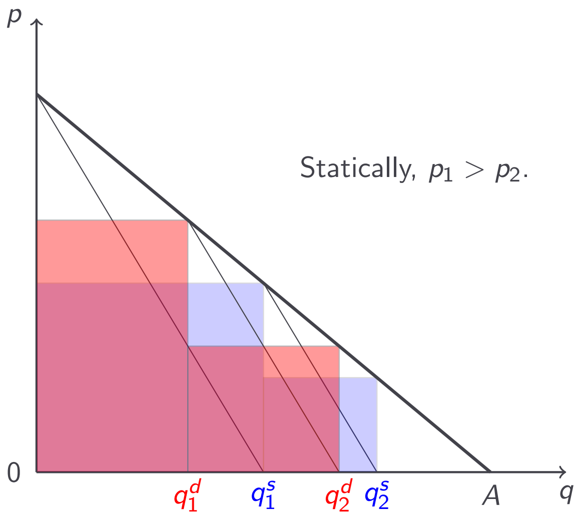
Intuition as Dynamic Monopolist, $b_1 = b_2$



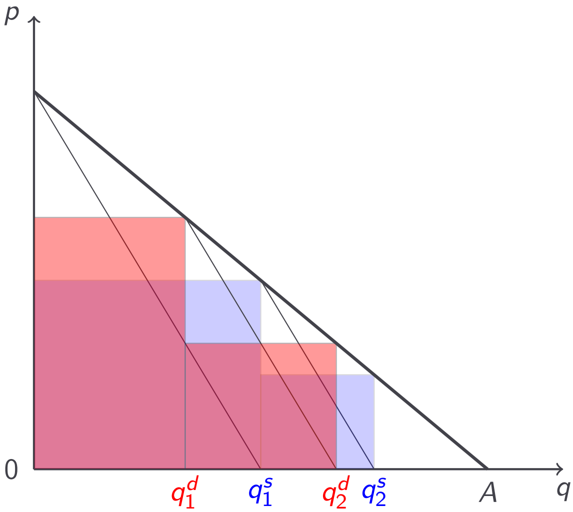
Intuition as Dynamic Monopolist, $b_1 = b_2$



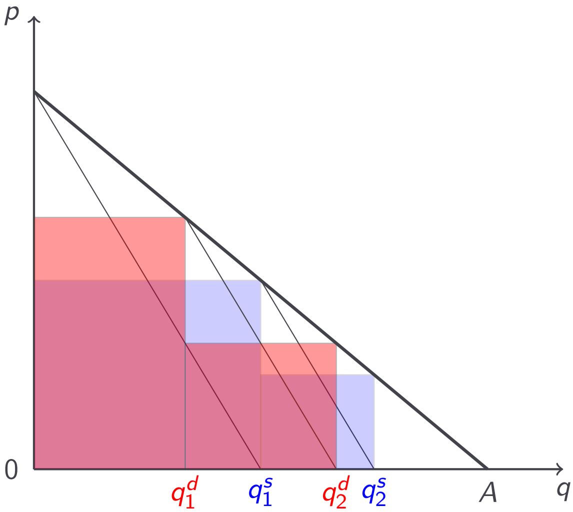
Intuition as Dynamic Monopolist, $b_1 = b_2$



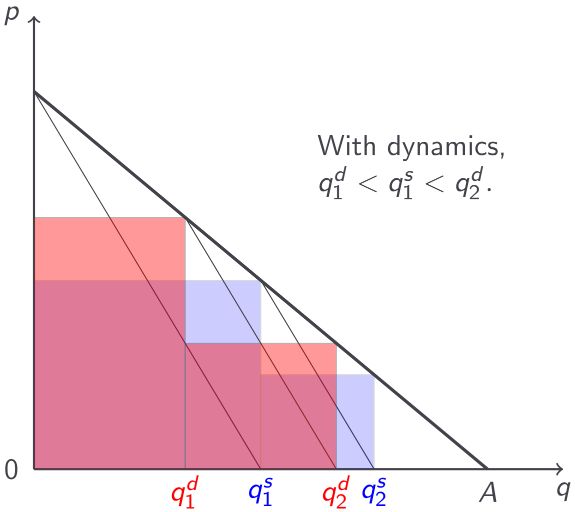
Intuition as Dynamic Monopolist, $b_1 = b_2$



Intuition as Dynamic Monopolist, $b_1 = b_2$

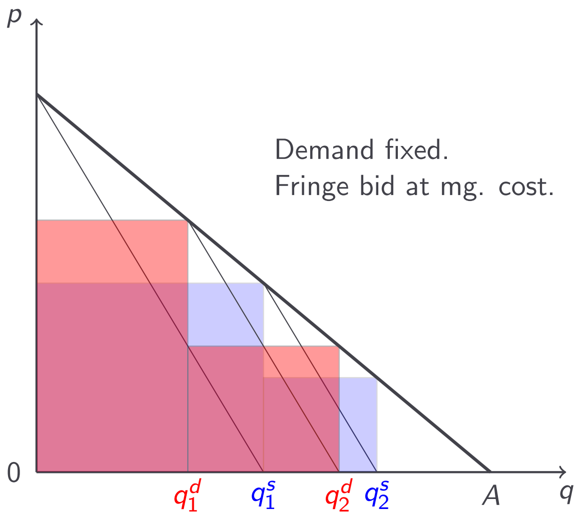


Intuition as Dynamic Monopolist, $b_1 = b_2$



With dynamics,
$q_1^d < q_1^s < q_2^d$.

Intuition as Dynamic Monopolist, $b_1 = b_2$



What could prevent arbitrage from demand?

- Day-ahead market plans for all expected demand.
  - Electricity cannot be stored economically in large amounts.
  - Demand and supply need to balance at real-time.
  - Some demand agents can arbitrage, but in a limited fashion.

- Equivalent to procurement auction in which auctioneer commits to allocating all quantity in a first market, and allows for secondary trade (e.g. Treasury auctions).

What could prevent arbitrage from suppliers?

- A key assumption in the simple model is that competitive producers just offer marginal cost curve.
- In practice, firms can (and *do*) engage in arbitrage.
- However, subject to limitations:
  1. Bidders need to have a physical asset to back their offers to generate (no virtual trading)—cannot bid larger than capacity.
  2. Large swings in physical schedule discouraged by the regulator.

Arbitrage by wind farms

- Wind is a technology particularly suited for arbitrage, even in the presence of institutional constraints.
- *Ability* to arbitrage:
    1. Capacity constraints are almost never binding.
    2. Less regulatory scrutiny, due to the inherent uncertain nature of its production (up to a certain limit).
- *Incentives* to arbitrage: if competitive.

In the Paper

- Theoretical predictions under different scenarios:
  - No arbitrage (baseline).
  - Full arbitrage.
  - Limited arbitrage (physical/regulatory constraints).
  - Strategic arbitrage (endogenous limited arbitrage).
  - Case with large firm vs small wind farm.
- Important aspects in common:
  - Declining price path (except full arbitrage).
  - Withholding by monopolist in the forward market (*even* with full arbitrage).
  - Prices above marginal cost of monopolist.

Summary of Predictions

- Institutional constraints on arbitrage and market power can give raise to declining prices,

$$p_1 > p_2 > \cdots > p_N.$$

- The price premium will be larger when:
  - Demand is large (A).
  - The residual demand in the first market is inelastic (b_1).
  - The residual demand in the second market is elastic (b_2).

- Firms may arbitrage some of these price differences,
  - *incentives* only if they do not have market power.

The Iberian Wholesale Electricity Market

- Sample: 2010-2012.
- Day-ahead and up to seven intra-day markets.
- Unit level equilibrium outcomes for each market.
- Detailed bidding data at the unit level (strategies).
- An interesting mix of dominant firms and fringe firms
  1. Four dominant firms (roughly 70% of market share)
  2. Many competitive fringe firms

Summary Statistics

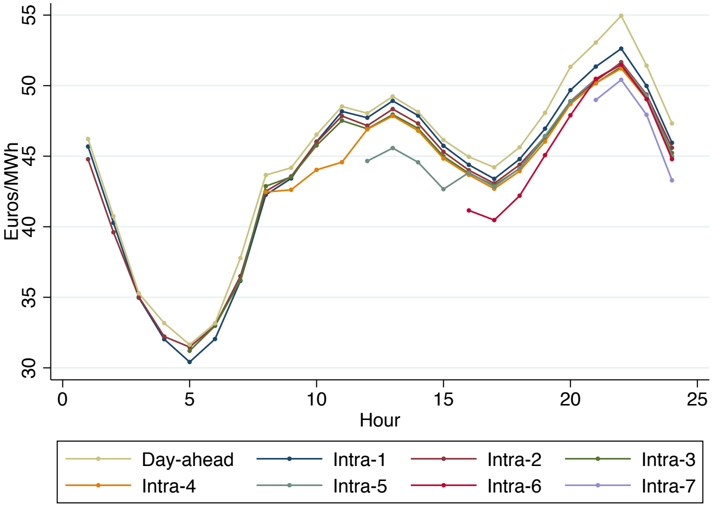
	Mean	SD	P25	P50	P75
Price Day-ahead (p_1)	44.7	14.1	38.6	48.0	53.5
Price Intra-day 1 (p_2)	43.8	13.9	38.0	46.2	52.5
Day-ahead premium ($p_1 - p_2$)	0.9	4.0	-0.4	0.5	2.6
Slope of DA Res. Demand (b_1)	343.2	102.9	281.9	316.4	369.9
Slope of I1 Res. Demand (b_2)	69.9	24.6	54.5	66.2	80.7
Demand Forecast (A)	29.3	5.2	24.8	29.4	33.3
Wind Forecast (q^w)	5.0	2.8	2.8	4.5	6.7

Notes: $N = 35,040$ hours. Prices in Euro/MWh. Slopes in MWh/Euro. Demand and wind forecasts in GWh.

Empirical exploration

1. Are there systematic price differences in the sequential markets?
2. Are they related to market power?
3. Do firms respond to price arbitrage opportunities?
   - Dominant firms
   - Competitive fringe firms

1. Are there systematic price differences?

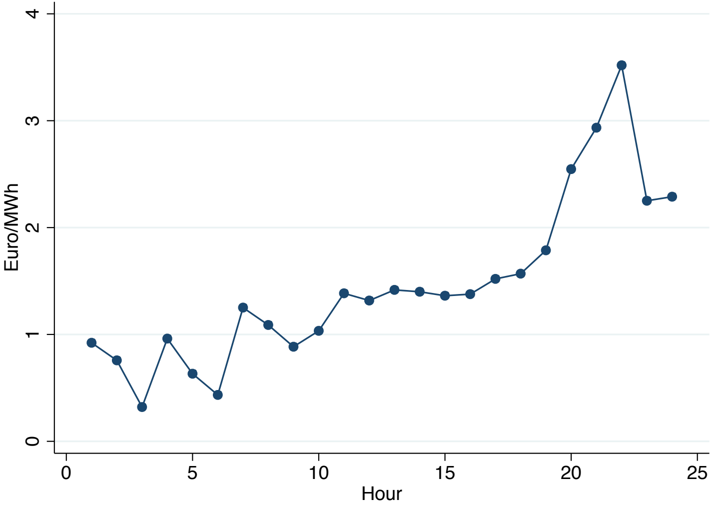


2. Are they related to market power?

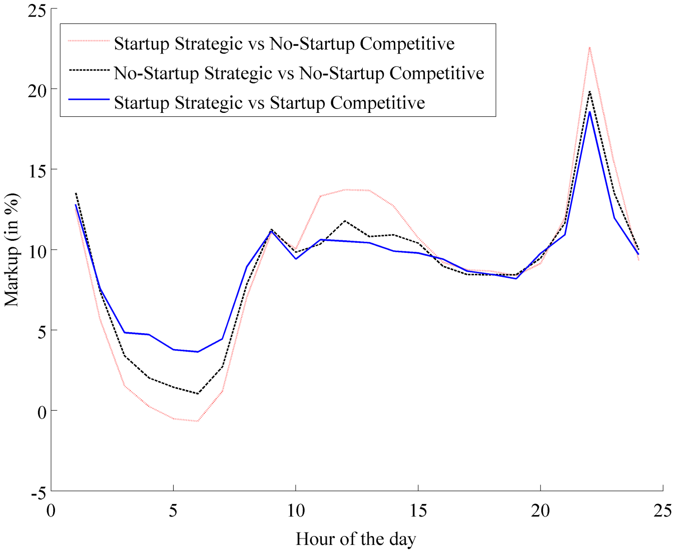
- Hours with more ability and incentives to exercise market power exhibit higher premia.
- Direction of premium in Spain consistent with market power on the sellers' side. What about the relative size across hours?

1. Compare $p_1 - p_2$ to traditional measures of market power.

Price Premium



Markups (Reguant, 2014)



2. Are they driven by market power?

- Hours with more ability and incentives to exercise market power exhibit higher premia.
- Direction of premium in Spain consistent with market power on the sellers' side. What about the relative size across hours?

1. Compare $p_1 - p_2$ to traditional measures of market power.
2. Regress $p_1 - p_2$ to predictors of market power.

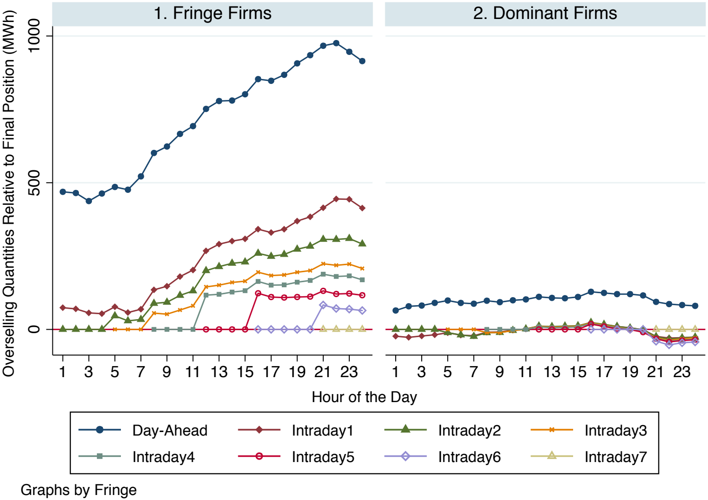
Regress Price Premium on Predictors of Market Power

1. Higher demand correlates with higher premium.
2. More elastic DA res. demand correlates with lower premium.
3. Less elastic RT res. demand correlates with lower premium.

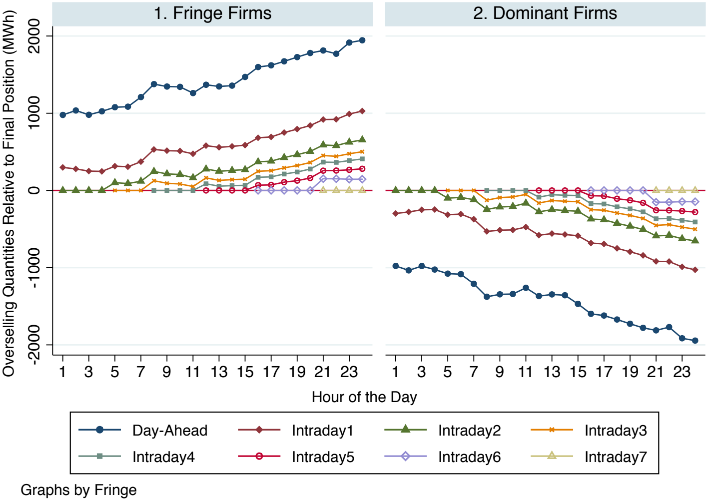
3. Do firms respond to price arbitrage opportunities?

- Two types of firms in the market:
  - Dominant firms that own wind and traditional power plants
  - Competitive fringe that own only wind
- Do firms oversell in forward markets relative to final position?
  1. Production from wind farms (q^w)
  2. Production from all power plants (Q)

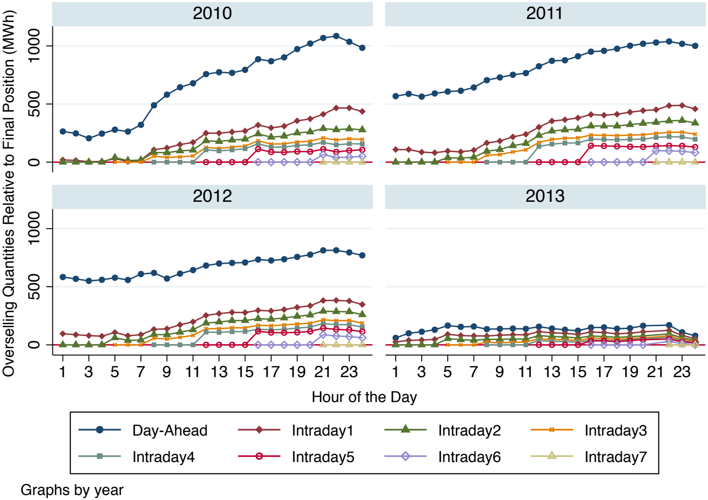
Overselling in forward markets: Wind farms



Overselling in forward markets: All power plants



The Effect of Policy Change in 2013: Fringe wind farms



Heterogeneity in Arbitrage by Fringe and Dominant Firms

$$\Delta \ln q_{jhtk} = \alpha + \beta \Delta \hat{p}_{htk} + \theta_j + \lambda_t + u_{htk}, \quad \text{with } k = \{\text{DA}, \text{I1}\}$$

By Power Plant Types

	Wind	Cogen	Demand	Thermal	Hydro	Solar	All Tech
Fringe	0.098	0.027	0.026	-0.006	0.034	0.007	0.057
	(0.006)	(0.003)	(0.002)	(0.003)	(0.009)	(0.007)	(0.003)
Dominant	0.006	-0.000	0.000	-0.024	-0.003	0.006	-0.131
	(0.005)	(0.003)	(0.001)	(0.004)	(0.003)	(0.005)	(0.010)
Fringe (2013)	0.025	0.019	0.029	-0.009	-0.002	0.031	0.023
	(0.022)	(0.012)	(0.003)	(0.006)	(0.011)	(0.021)	(0.010)
Dominant (2013)	0.000	0.001	-0.001	-0.039	0.002	-0.011	-0.147
	(0.011)	(0.003)	(0.001)	(0.010)	(0.004)	(0.003)	(0.021)

- Fringe firms use wind, cogent, demand, hydro for arbitrage
- Arbitrage by wind is the largest

Summary of empirical evidence

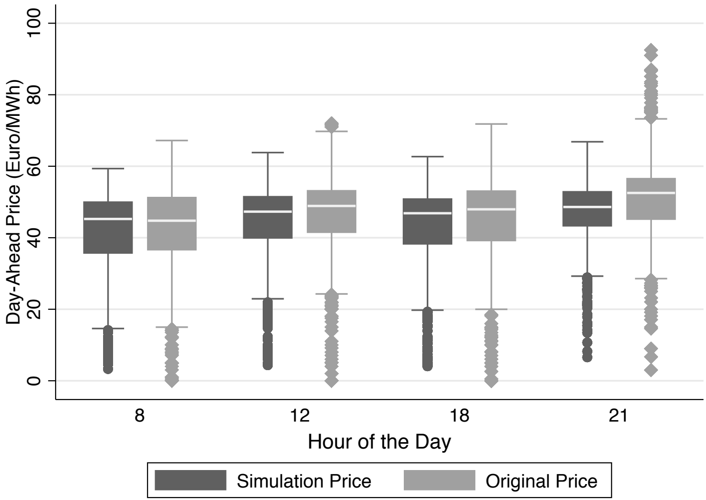
1. Are there systematic price differences in the sequential markets?
   - Systematic forward-market price premium
2. Are they related to market power?
   - Consistent evidence using several methods
3. Do firms respond to price arbitrage opportunities?
   - Only fringe firms arbitrage

- What are the welfare effects of sequential markets from a market power point of view?
- Does arbitrage improve welfare?

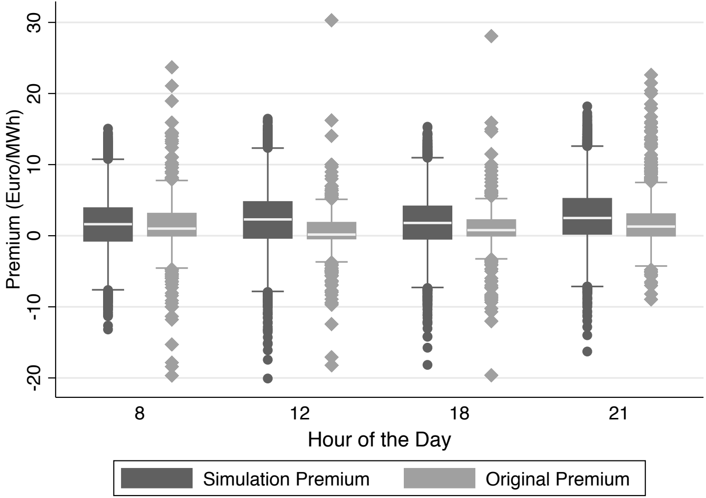
Counterfactual Model

- Extends theoretical framework:
  - 4 strategic firms, 2 sequential markets.
  - Firms play Cournot, taking residual demand as given.
  - Marginal cost curve represented as a piece-wise linear function.
  - Uncertainty about exact demand A in period 2.
- From data, build:
  - Residual demand slopes (b_1, b_2).
  - Cost-curves at firm-level (engineering estimates).
  - Approximate distribution of uncertainty in A.
- Solved by backward induction.

Baseline Prices



Baseline Premium



What are the welfare effects of arbitrage?

- Difficulties in forecasting wind have generated debate, concerns about its challenges.
- Arbitrage by wind farms is potentially inefficient, as it makes wind planning harder.

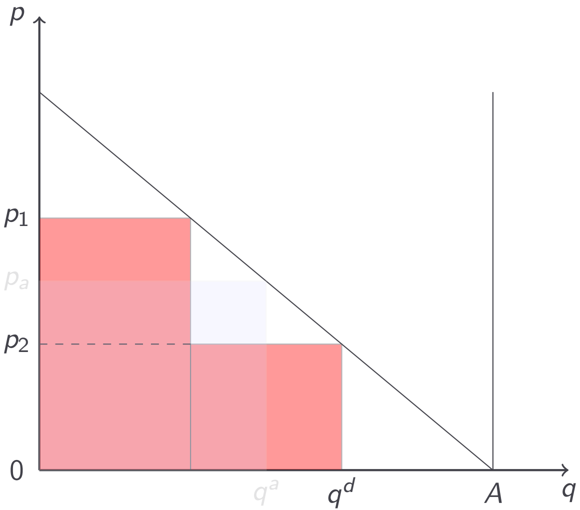
- **Policy implication 1**: Better to decouple wind planning from arbitrage, with financial bidders (Jha and Wolak, 2014).

What are the welfare effects of arbitrage?

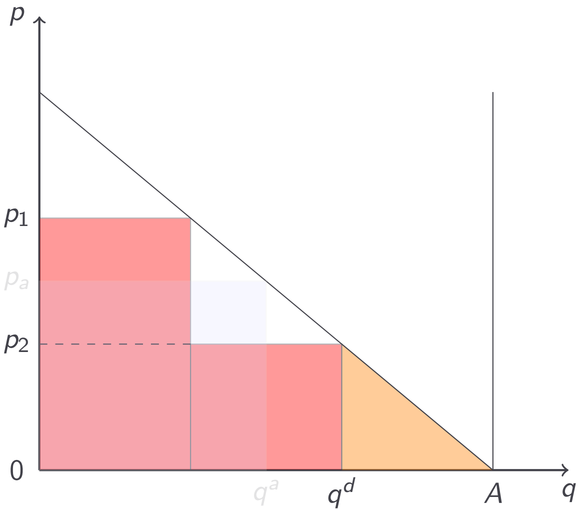
- More broadly, is arbitrage in itself, even if costless, efficient?
- Market design and institutions induce dynamic monopoly pricing.
- Arbitrage takes away price discrimination, reducing consumer costs, but increasing withholding (deadweight loss).

- **Policy implication 2**: Arbitrage does *not* necessarily improve efficiency.

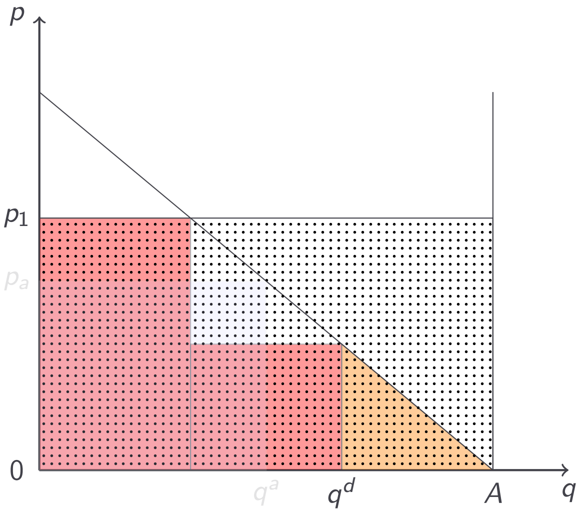
Intuition as Dynamic Monopolist, $b_1 = b_2$



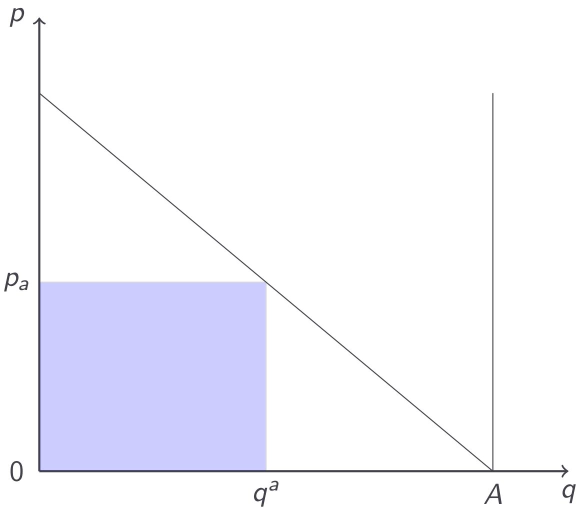
Intuition as Dynamic Monopolist, $b_1 = b_2$



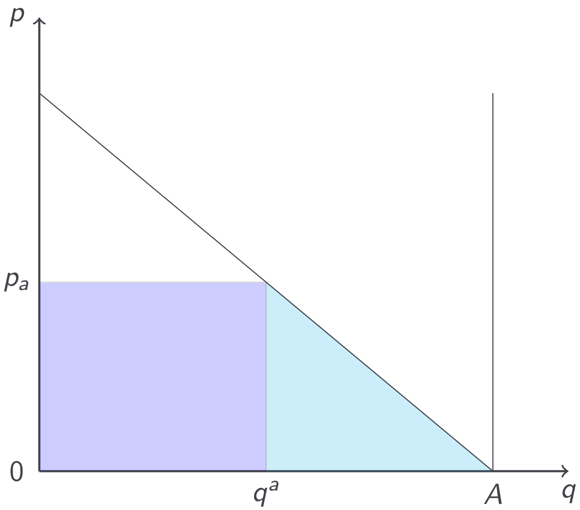
Intuition as Dynamic Monopolist, $b_1 = b_2$



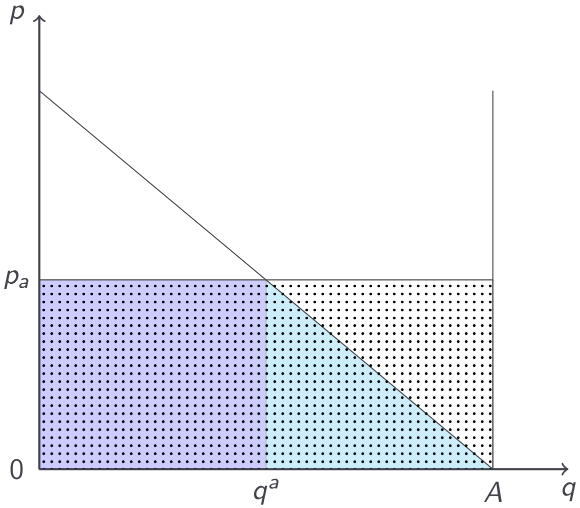
Intuition as Dynamic Monopolist, $b_1 = b_2$



Intuition as Dynamic Monopolist, $b_1 = b_2$



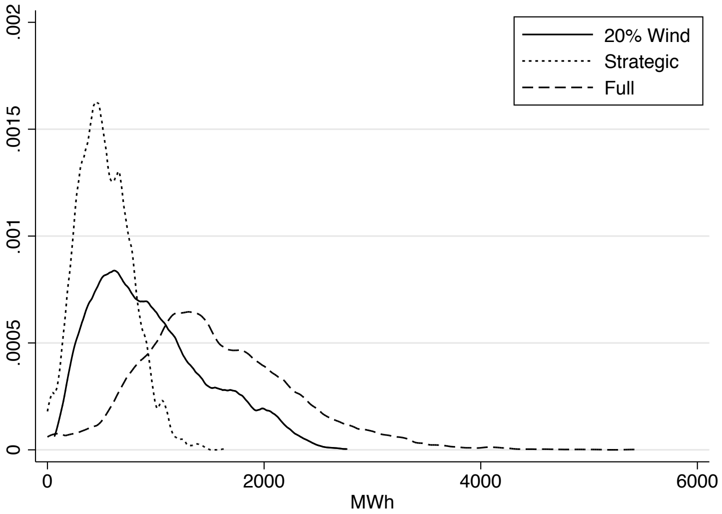
Intuition as Dynamic Monopolist, $b_1 = b_2$



Counterfactual Experiments

- **Wind Arbitrage (Baseline):** Wind farms overbid by 20%.
- **Full Arbitrage (Single Market):** Perfect full arbitrage with no dynamic costs.
- **Sequential Market, No Arbitrage:** Zero arbitrage, maximal price discrimination.
- **Sequential Market, Strategic Arbitrage:** Profit-maximizing single arbitrageur.

Implied Arbitrage by Alternative Models



Hourly Welfare Comparison Across Counterfactuals

	p_1	p_2	Premium (E/MWh)	Q_1 (GWh)	$Q_1 + Q_2$ (GWh)	Dominant Profit (000E)	Δ Ineff. from FB (000E)	Δ Cons. Cost from FB (000E)
First best (b_1)	-	38.2	-	-	15.3	60.5	-	-
Spot only (b_1)	-	46.5	-	-	12.8	123.2	17.2	265.5
Case $b_2 = b_1$								
No arbitrage	45.1	39.5	5.6	13.2	14.9	122.0	1.3	221.8
Str. arbitrage	44.6	40.2	4.4	12.0	14.7	119.0	1.7	204.3
Wind 20%	44.7	39.9	4.9	12.4	14.8	116.4	1.5	210.3
Full Arbitrage	42.5	42.5	0.0	7.7	14.0	100.7	4.8	138.0
Case $b_2 < b_1$								
No arbitrage	44.0	38.7	5.3	13.6	13.9	112.3	5.8	186.1
Str. arbitrage	43.8	40.3	3.5	13.1	13.8	111.4	6.2	180.8
Wind 20%	43.7	41.5	2.2	12.7	13.8	110.0	6.4	178.4
Full Arbitrage	43.5	43.5	0.0	12.2	13.7	108.3	7.1	170.3
Original Data	46.0	44.8	1.3	12.1	13.8	-	-	-

- Two sequential markets contribute to a better allocation. Allaz and Vila (1993) mechanism (requires at least two firms).

Hourly Welfare Comparison Across Counterfactuals

	p_1	p_2	Premium (E/MWh)	Q_1 (GWh)	$Q_1 + Q_2$ (GWh)	Dominant Profit (000E)	Δ Ineff. from FB (000E)	Δ Cons. Cost from FB (000E)
First best (b_1)	-	38.2	-	-	15.3	60.5	-	-
Spot only (b_1)	-	46.5	-	-	12.8	123.2	17.2	265.5
Case $b_2 = b_1$								
No arbitrage	45.1	39.5	5.6	13.2	14.9	122.0	1.3	221.8
Str. arbitrage	44.6	40.2	4.4	12.0	14.7	119.0	1.7	204.3
Wind 20%	44.7	39.9	4.9	12.4	14.8	116.4	1.5	210.3
Full Arbitrage	42.5	42.5	0.0	7.7	14.0	100.7	4.8	138.0
Case $b_2 < b_1$								
No arbitrage	44.0	38.7	5.3	13.6	13.9	112.3	5.8	186.1
Str. arbitrage	43.8	40.3	3.5	13.1	13.8	111.4	6.2	180.8
Wind 20%	43.7	41.5	2.2	12.7	13.8	110.0	6.4	178.4
Full Arbitrage	43.5	43.5	0.0	12.2	13.7	108.3	7.1	170.3
Original Data	46.0	44.8	1.3	12.1	13.8	-	-	-

- Sequential markets reduce costs by 1-2% exclusively due to reductions in market power.

Hourly Welfare Comparison Across Counterfactuals

	p_1	p_2	Premium (E/MWh)	Q_1 (GWh)	$Q_1 + Q_2$ (GWh)	Dominant Profit (000E)	Δ Ineff. from FB (000E)	Δ Cons. Cost from FB (000E)
First best (b_1)	-	38.2	-	-	15.3	60.5	-	-
Spot only (b_1)	-	46.5	-	-	12.8	123.2	17.2	265.5
Case $b_2 = b_1$								
No arbitrage	45.1	39.5	5.6	13.2	14.9	122.0	1.3	221.8
Str. arbitrage	44.6	40.2	4.4	12.0	14.7	119.0	1.7	204.3
Wind 20%	44.7	39.9	4.9	12.4	14.8	116.4	1.5	210.3
Full Arbitrage	42.5	42.5	0.0	7.7	14.0	100.7	4.8	138.0
Case $b_2 < b_1$								
No arbitrage	44.0	38.7	5.3	13.6	13.9	112.3	5.8	186.1
Str. arbitrage	43.8	40.3	3.5	13.1	13.8	111.4	6.2	180.8
Wind 20%	43.7	41.5	2.2	12.7	13.8	110.0	6.4	178.4
Full Arbitrage	43.5	43.5	0.0	12.2	13.7	108.3	7.1	170.3
Original Data	46.0	44.8	1.3	12.1	13.8	-	-	-

- Full arbitrage minimizes costs to consumers, but not production costs.

Hourly Welfare Comparison Across Counterfactuals

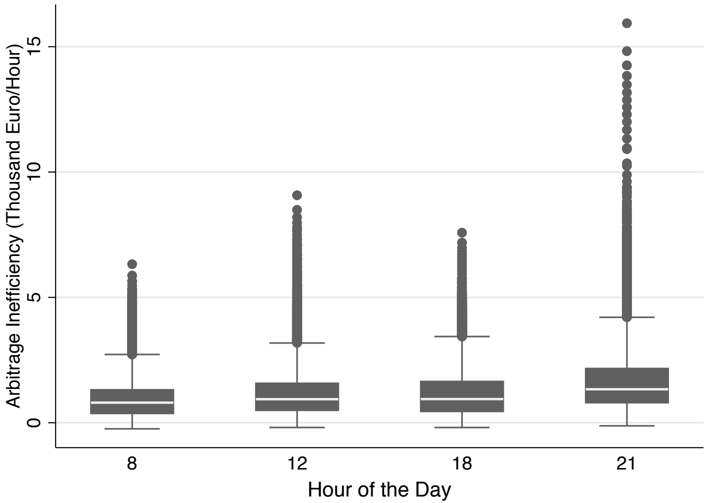
	p_1	p_2	Premium (E/MWh)	Q_1 (GWh)	$Q_1 + Q_2$ (GWh)	Dominant Profit (000E)	Δ Ineff. from FB (000E)	Δ Cons. Cost from FB (000E)
First best (b_1)	-	38.2	-	-	15.3	60.5	-	-
Spot only (b_1)	-	46.5	-	-	12.8	123.2	17.2	265.5
Case $b_2 = b_1$								
No arbitrage	45.1	39.5	5.6	13.2	14.9	122.0	1.3	221.8
Str. arbitrage	44.6	40.2	4.4	12.0	14.7	119.0	1.7	204.3
Wind 20%	44.7	39.9	4.9	12.4	14.8	116.4	1.5	210.3
Full Arbitrage	42.5	42.5	0.0	7.7	14.0	100.7	4.8	138.0
Case $b_2 < b_1$								
No arbitrage	44.0	38.7	5.3	13.6	13.9	112.3	5.8	186.1
Str. arbitrage	43.8	40.3	3.5	13.1	13.8	111.4	6.2	180.8
Wind 20%	43.7	41.5	2.2	12.7	13.8	110.0	6.4	178.4
Full Arbitrage	43.5	43.5	0.0	12.2	13.7	108.3	7.1	170.3
Original Data	46.0	44.8	1.3	12.1	13.8	-	-	-

- Price reductions can be substantially limited if the secondary market is not responsive.

Implications

- Sequential markets improve allocation versus single market.
  - With several firms, it reduces their market power (Allaz and Vila, 1993).
- Institutional design allocates demand in the first market, and discourages arbitrage, preventing full arbitrage.
- Welfare effects of full arbitrage under imperfect competition:
  - Full arbitrage is not necessarily welfare improving in the presence of market power
  - Because it reduces productive efficiency.

Inefficiencies from Arbitrage (Full vs. No Arbitrage)



Summary of today's lecture

- Simple models of competition can be used to describe the operation of electricity markets.
- These are still highly dimensional markets with substantial complexity.
- Modeling assumptions are used to simplify the framework and make progress.

Next steps

- How to build models of electricity markets?
- How to use clustering to simplify models and data?
- How to incorporate market power in computation?