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# **The Efficiency of Uniform-Price Electricity Auctions: Evidence from Bidding Behavior in ERCOT**

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# Outline of Presentation

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- What makes an electricity market “efficient”?
- Do balancing auctions provide incentives for generators to bid in a manner that promotes efficiency?
- Evidence from ERCOT:
  - How much inefficiency?
  - What is the cause of inefficient bidding behavior?
- Implications for two types of stakeholders:
  - Market monitors
  - Generators

# What Is an “Efficient” Wholesale Market?

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- Price is the marginal cost (MC), or the cost of last MWh required to serve load
- Short run:
  - If most efficient units not scheduled day-ahead, signals optimal “reshuffling” of generation to get least cost dispatch.
- Long run:
  - Signals value/location of new generation

# Problems with Generators Submitting Bids $\neq$ Marginal Cost

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- Typical concern: large generator bidding (INC) substantially above MC
  - Prices “high”
  - May withhold low cost units to raise the price
- Small generator bidding (INC) substantially above MC
  - Prices “high”
  - Inefficient dispatch
- Any generator bidding (DEC) substantially below MC
  - Prices too *low*!
  - Inefficient dispatch

# Simple Example

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- Units have MC varying from \$30 to \$120
- Given load, least cost dispatch → Price=\$80
- Generator A:
  - Owns \$100 unit
  - Signed bilateral deal so schedules unit day-ahead
- Generator B:
  - Owns \$60 unit
  - Only scheduled half of capacity day-ahead
- Efficiency: A will DEC, B will INC
- Bad outcome:
  - A submits a (low) \$40 DEC bid
  - B submits a (high) \$120 INC bid

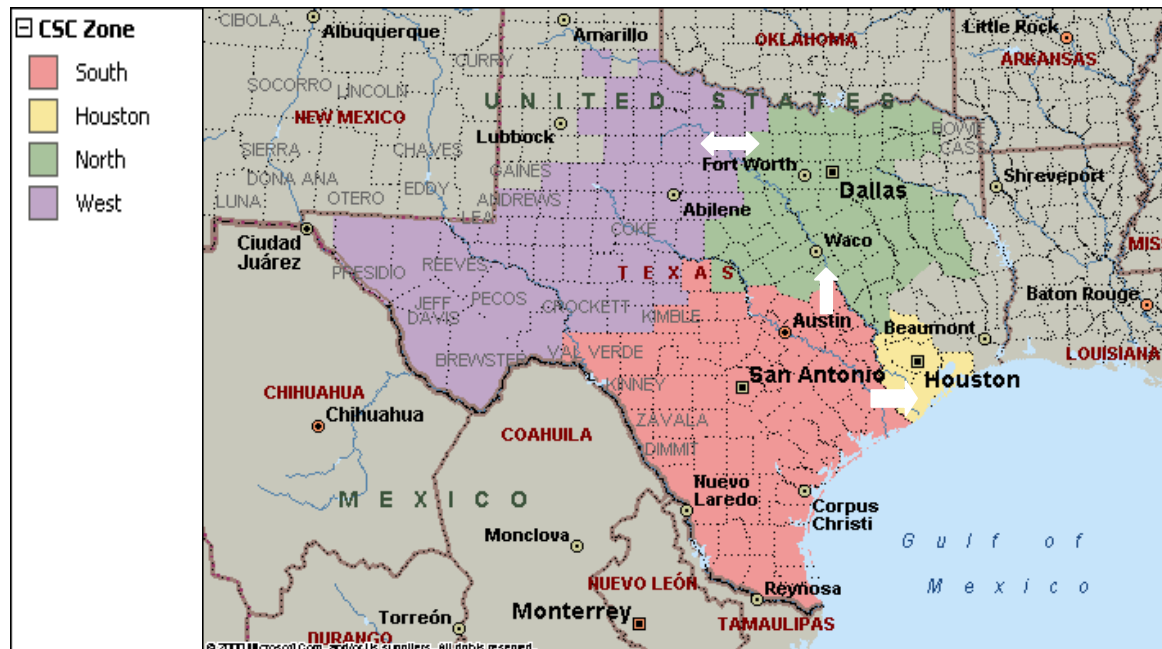
# Market Power in a Balancing Market

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- Suppose no further contract obligations upon entering balancing market
- INCremental demand periods
  - Bid above MC to raise revenue on inframarginal sales
  - Just “monopolist on residual demand”
- DECremental demand periods
  - Bid below MC to reduce output
  - Make yourself “short” but drive down the price of buying your short position (monopsony)

# Texas Electricity Market

- ERCOT balancing market opened August 2001
- Incumbents
  - Implicit contracts to serve non-switching customers at regulated price
- Various merchant generators



# Electricity Market Mechanics

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- Forward contracting
  - Generators contract w/ buyers beforehand for a delivery quantity and price
  - Day before production: fixed quantities of supply and demand are scheduled w/ grid operator
  - (Generators may be net short or long on their contract quantity)
- Spot (balancing) market
  - Centralized market to balance realized demand with scheduled supply
  - Generators submit “supply functions” to increase or decrease production from day-ahead schedule

# Balancing Energy Market

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- Approx 2-5% of energy traded (“up” and “down”)
  - “up” → bidding price to receive to produce more
  - “down” → bidding price to pay to produce less
- Uniform-price auction using hourly portfolio bids that clear every 15-minute interval
- Bids: monotonic step functions with up to 40 “elbow points” (20 up and 20 down)
- Market separated into zones if transmission lines congested – we focus on uncongested hours

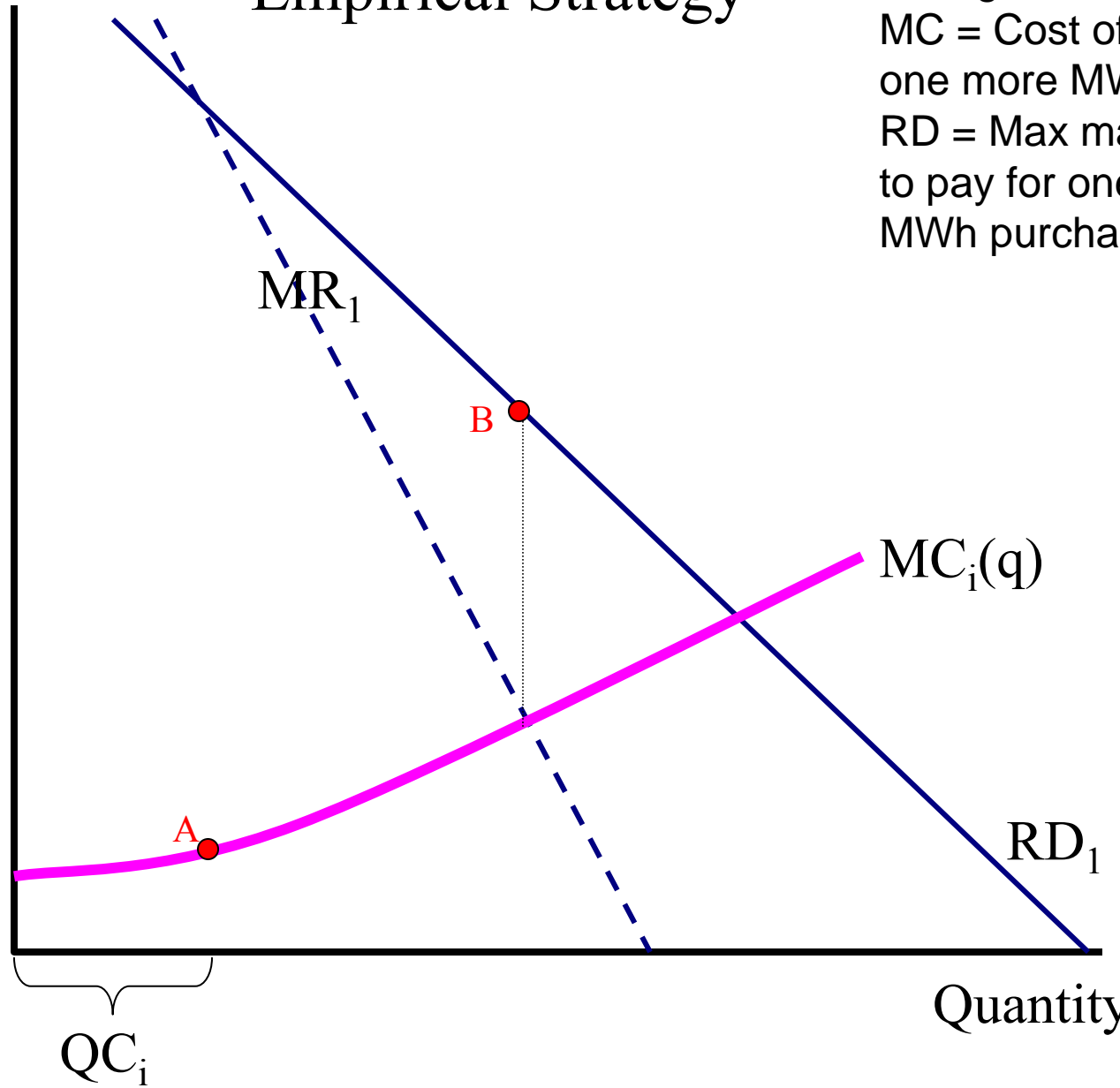
# Who are the Players?

Table 1: Generation Ownership

<b>Owner</b>	<b>% of Installed Capacity</b>
TXU	24
Reliant	18
City of San Antonio Public Service	8
Central Power & Light	7
City of Austin	6
Calpine	5
Lower Colorado River Authority	4
Lamar Power Partners	4
Guadalupe Power Partners	2
West Texas Utilities	2
Midlothian Energy	2
Dow Chemical	1
Brazos Electric Power Cooperative	1
Others	16

# Empirical Strategy

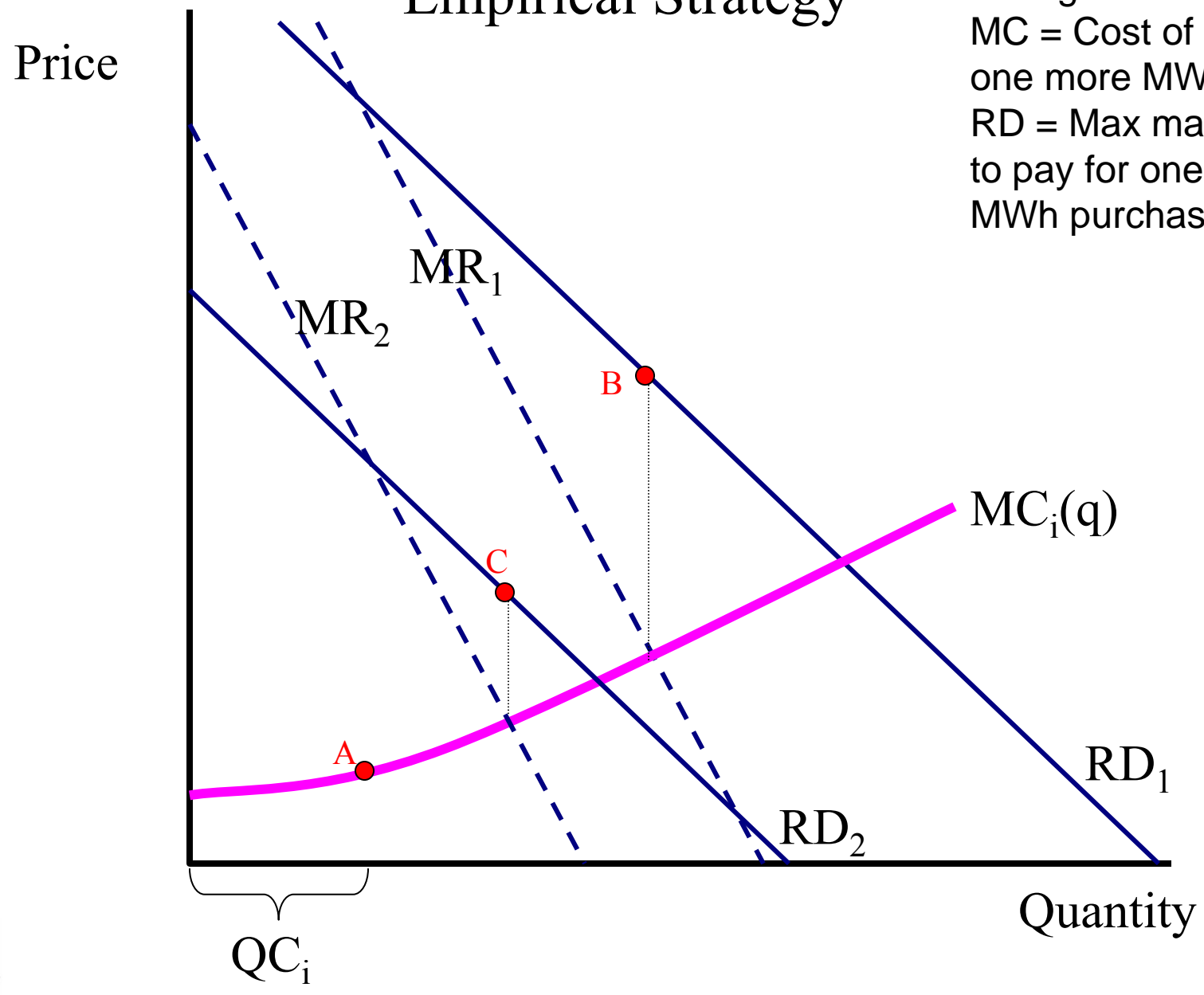
Price



MR = Revenue from selling one more MWh  
MC = Cost of producing one more MWh  
RD = Max market willing to pay for one more MWh purchased

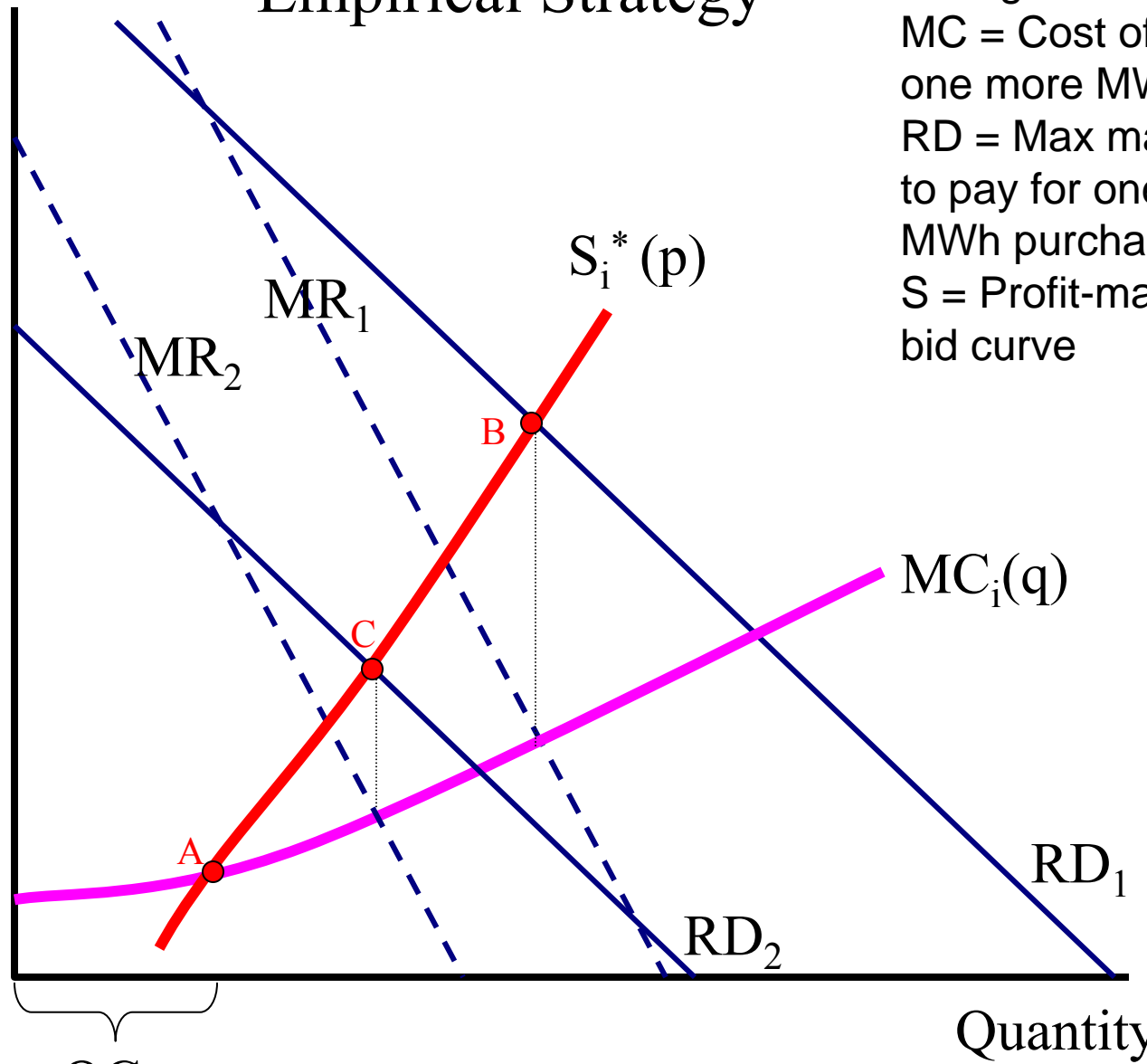
# Empirical Strategy

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# Empirical Strategy

Price



MR = Revenue from selling one more MWh  
MC = Cost of producing one more MWh  
RD = Max market willing to pay for one more MWh purchased  
S = Profit-maximizing bid curve

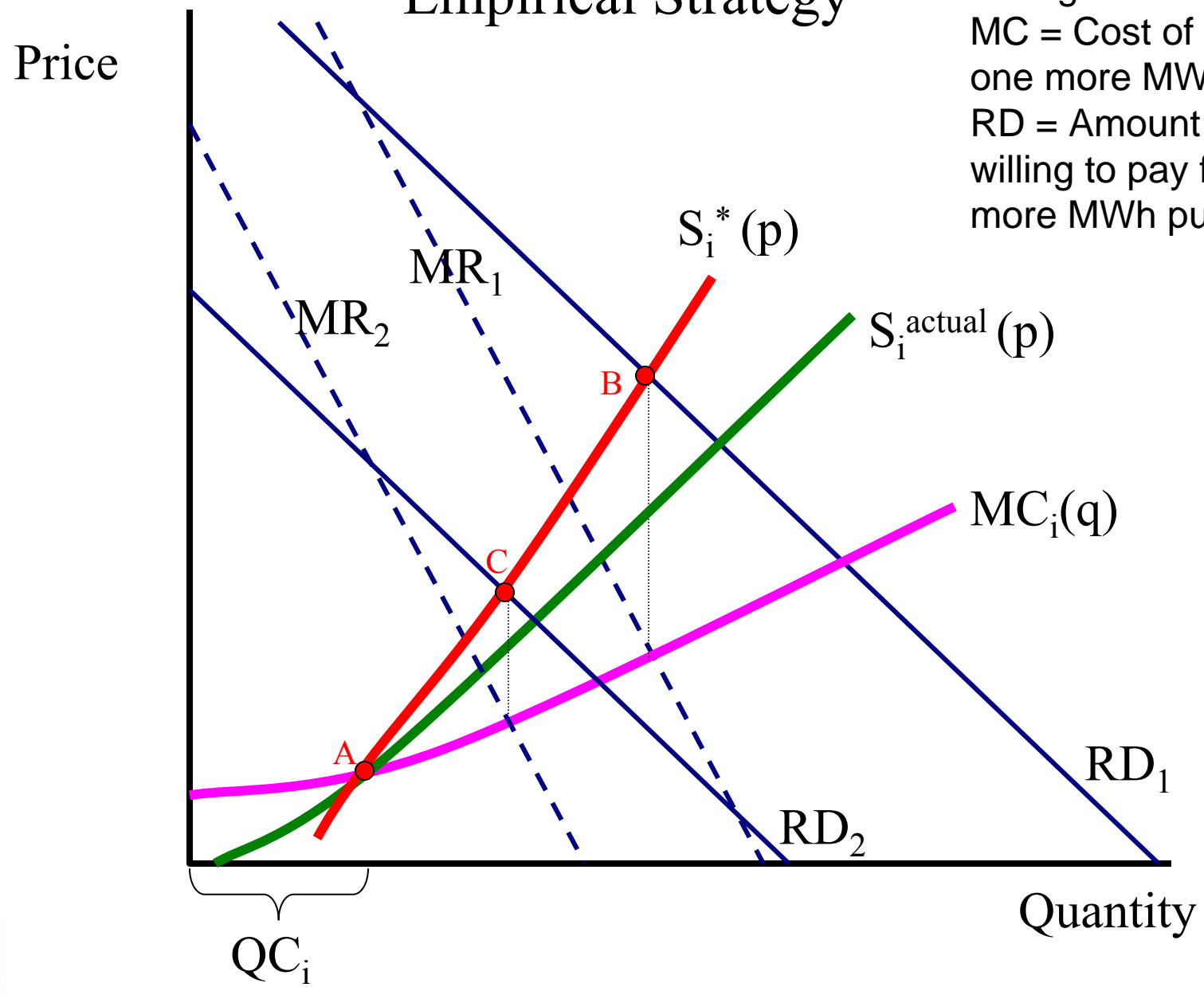
$QC_i$

Quantity

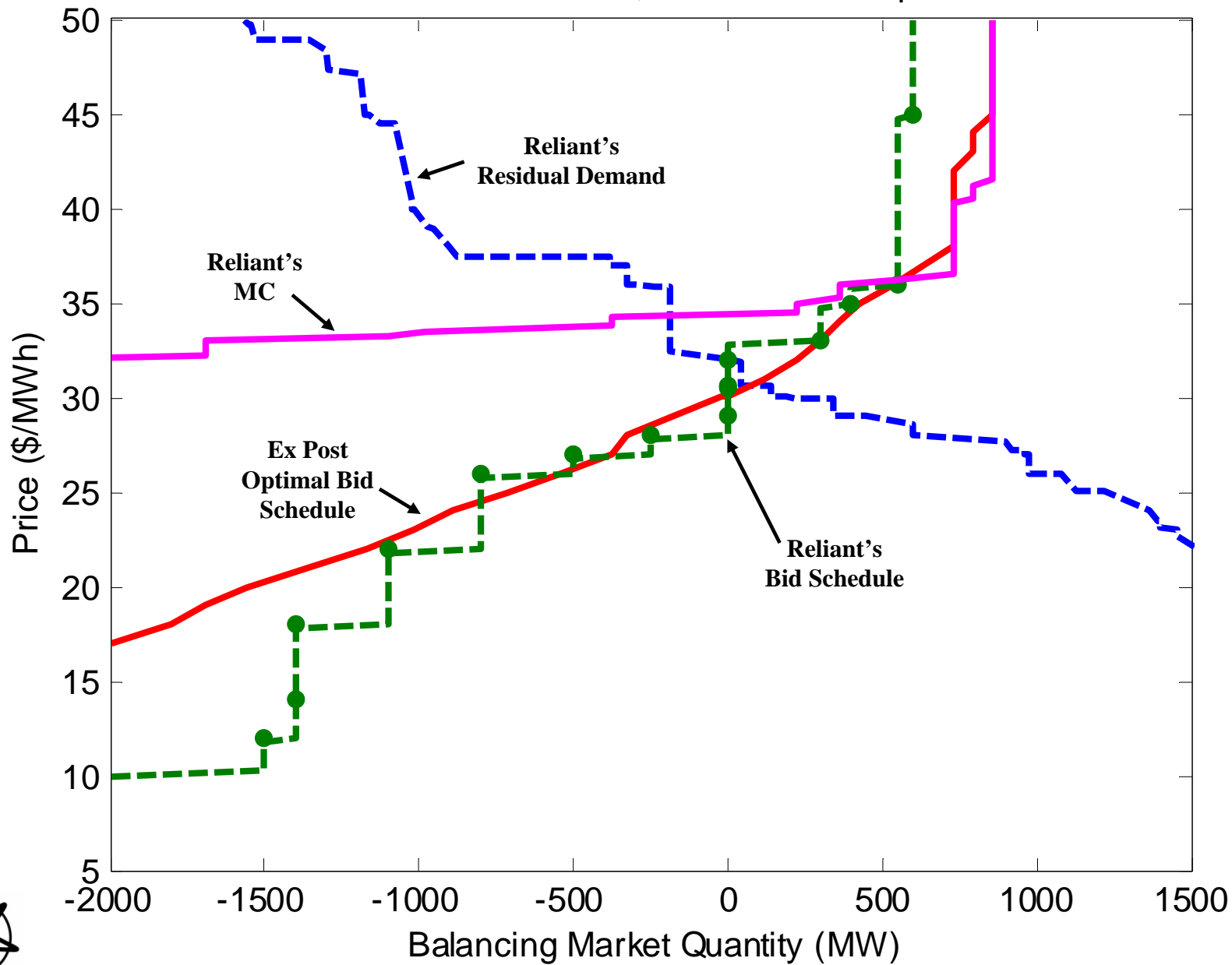


# Empirical Strategy

MR = Revenue from selling one more MWh  
 MC = Cost of producing one more MWh  
 RD = Amount market willing to pay for one more MWh purchased



Reliant on June 4, 2002 6:00-6:15pm



# Preview of Results

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- Largest firm bids close to benchmarks for optimal bidding
- Small firms significantly deviate, but there's some evidence of improvement over time
- Efficiency losses from “unsophisticated” bidding at least as large as losses from “market power”

# Uniform-Price Auction Model of ERCOT

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- Setup
  - Static game,  $N$  firms, costs of generation  $C_{it}(q)$
  - Contract quantity ( $QC_{it}$ ) and price ( $PC_{it}$ )
  - Total demand  $\tilde{D}_t = D + \varepsilon_t$
  - Generators bid supply functions  $S_{it}(p)$
- Market-clearing price ( $p^c$ ) given by (removing  $t$  subscript from now on):

$$\sum_{i=1}^N S_i(p^c) = \tilde{D}$$

# Model (cont'd)

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- Ex-post profit:

$$\pi_i = S_i(p^c)p^c - C_i(S_i(p^c)) - (p^c - PC_i)QC_i$$

- Information Structure

- $C_i(q)$  common knowledge

- Private information:

- $QC_i$

- $PC_i$  – but does not affect maximization problem

- $\tilde{D}$  is unknown

➔ important sources of uncertainty from perspective of bidder  $i$

- Rival contract positions ( $QC_{-i}$ ) and total demand ( $\varepsilon$ )

# Characterization of Bayesian Nash Equilibrium\*

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Strategies :  $S_i(p, QC_i)$

$QC_{-i}, \tilde{D}$  have joint distribution  $F(QC_{-i}, \tilde{D} | QC_i)$  (possibly correlated)

Following Wilson's (1979) share auction model, define the probability distribution of market - clearing price, conditional on supply function

$\hat{S}_i(p)$  and  $QC_i$ , given that other firms follow strategy profile  $S_{-i}(p, QC_{-i})$ :

$$\begin{aligned} H(p, \hat{S}_i(p)) &\equiv \Pr\{p^c \leq p \mid QC_i, \hat{S}_i(p)\} \\ &= \Pr\left\{\sum_{j \in -i} S_j(p, QC_j) + \hat{S}_i(p) \geq \tilde{D} \mid QC_i, \hat{S}_i(p)\right\} \\ &= \int_{QC_{-i} \times \varepsilon} 1\left\{\sum_{j \in -i} S_j(p, QC_j) + \hat{S}_i(p) \geq D + \varepsilon\right\} dF(QC_{-i}, \varepsilon \mid QC_i) \end{aligned}$$



\* NE = A bidding outcome where bidders can't improve profitability by changing their bid.

# Equilibrium (cont'd)

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Bidders choose supply functions to maximize expected profits

$$\max_{\hat{S}_i(p)} \int_{\underline{p}}^{\bar{p}} p \hat{S}_i(p) - C_i(\hat{S}_i(p)) - (p - PC_i) QC_i dH_i(p, \hat{S}_i(p); QC_i)$$

If  $H(\cdot)$  is differentiable, necessary condition for pointwise optimality of  $S_i^*(p)$ :

$$p - C'_i(S_i^*(p)) = (S_i^*(p) - QC_i) \frac{H_s(p, S_i^*(p); QC_i)}{H_p(p, S_i^*(p); QC_i)}$$

# Equilibrium (cont'd)

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CLAIM: If we restrict the class of supply functions:

$$S_i(p) = \alpha_i(p) + \beta_i(QC_i)$$

then (ex ante) equilibrium bids are ex post best responses:

$$p - C'_i(S_i^*(p)) = \frac{RD_i(p) - QC_i}{RD'_i(p)}$$

where

$$RD_i(p) = D(p) - \sum_{j \neq i} S_j(p)$$

# Computing Ex Post Optimal Bids

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Ex post best response is Bayesian Nash Eqbm

→ Uncertainty shifts residual demand parallel in & out

(observed realization of uncertainty provides  
“data” on  $RD_i'(p)$  for all other possible realizations)

→ Can trace out ex post optimal/equilibrium bid point  
for every realization of uncertainty (distribution of  
uncertainty doesn't matter)

$$p - MC_i(\underbrace{S_i^*(p)}_{Unknown}) = \frac{\overbrace{S_i^*(p) - QC_i}^{Unknown}}{RD_i'(p)} \quad (\text{"inverse elasticity rule"})$$

# Sample Bidding Interface

ACS BTU ERCOT

Wednesday 7-Jan-2004 Local Time: 11:44

Date: Trade Date: 15 minutes for the day of Wednesday 7-Jan-2004

View: Scheduling for: BTU (QSE) Bryan Texas Utilities

Filter: Perspective: Balance Description: Balance Provision Equals ERCOT AS Deployment Balance Up Energy OR ERCOT

Grid: Averaged Current Hour: 11:44

Filter Set: ERCOT Filter on:

Energy balance AS Balance AS Bid / Award AS Dispatch

Schedule Description	9:15	9:30	9:45	10:00	10:15
BTU-BTU D F Dansby Down Balance	100	100	100	100	100
*: DownBalancingEnergy	0.00	0.00	0.00	0.00	0.00
BTU-BTU E F ERCOT AS Deployment Down	100	100	100	100	100
BTU-BTU E F ERCOT AS Deployment Up Er	0.00	0.00	0.00	0.00	0.00
*: Energy					15
BTU-BTU (ERCO) N F ERCOT AS Bid - Awar	14	14	14	14	30
BTU-BTU N F Atkins7 Non-Spinning Reserv	11.69	11.69	11.69	11.69	7.11
BTU-BTU N F Dansby Non-Spinning Reserv	20	20	20	20	20
*: NonSpinningReserve	0.00	0.00	0.00	0.00	0.00
BTU-BTU (ERCO) R F ERCOT AS Bid - Awar	0	0	0	0	16
*: RegulationDown	0.00	0.00	0.00	0.00	0.00
BTU-BTU (ERCO) R F ERCOT AS Bid - Awar	5	5	5	5	11
*: RegulationUp	6.25	6.25	6.25	6.25	4.88
BTU-BTU (ERCO) R F ERCOT AS Bid - Awar	5	5	5	5	15
*: RegulationUp	1.56	1.56	1.56	1.56	1.22
BTU-BTU (ERCO) R F ERCOT AS Bid - Awar	5	5	5	5	15
*: RegulationUp	7.80	7.80	7.80	7.80	5.00
BTU-BTU (ERCO) R F ERCOT AS Bid - Awar	5	5	5	5	15
*: RegulationUp	1.95	1.95	1.95	1.95	1.25
BTU-BTU (ERCO) R F ERCOT AS Bid - Awar	2	2	2	2	3

**Market Bid**

Market Bid Strategy: 010704\_DBES

Bid Type: ERCOT Bid

Period Ending	Quantity	Bid Price
1:00	0	68.85
1:00	15	68.84
1:00	16	15
1:00	45	14
2:00	0	68.85
2:00	5	68.84
2:00	6	15
2:00	45	14
3:00	0	68.85
3:00	4	68.84
3:00	5	15
3:00	35	14

Delete Row Clear

New Save Delete

OK Cancel

Bid BE	Premiums - Public	Dynamic Balance	Interchange
00	12:15	12:30	12:45
100	100	100	100
0.00	0.00	0.00	0.00
100	100	100	100
0.00	0.00	0.00	0.00
9	8	8	8
5.97	5.84	5.84	5.84
9	8	8	8
1.49	1.46	1.46	1.46
5	5	5	5
7.80	7.80	7.80	7.80
5	5	5	5
1.95	1.95	1.95	1.95
2	2	2	2



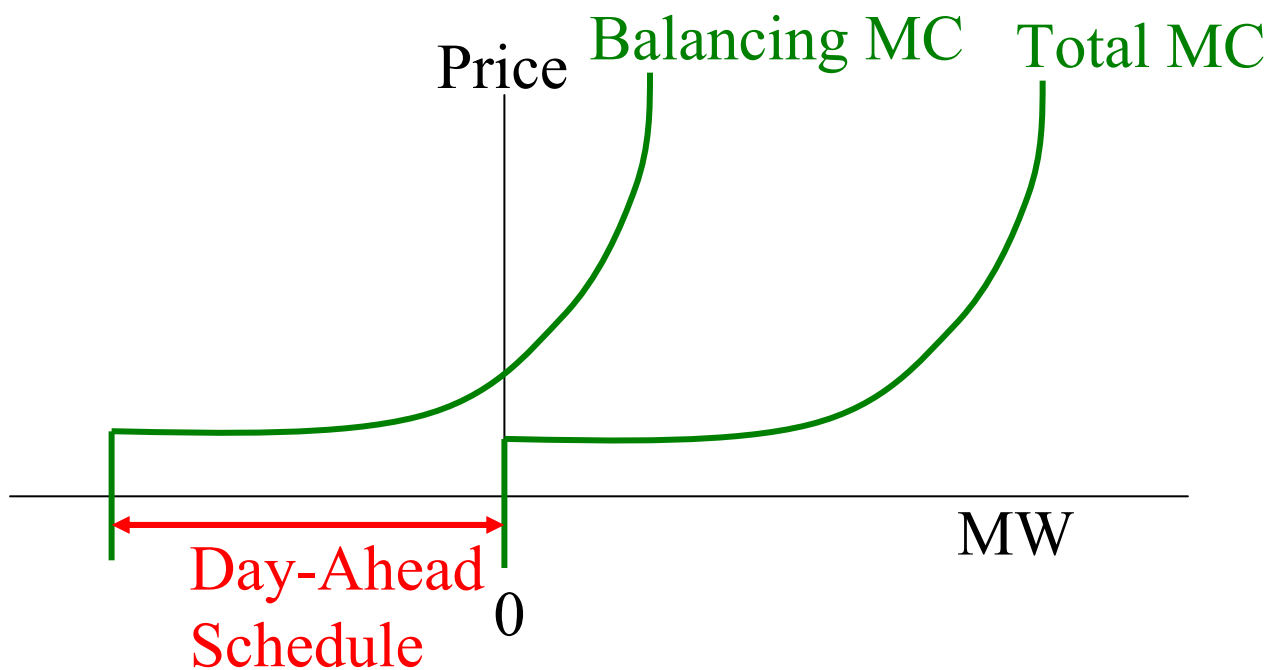
# Data (Sept 2001 thru Jan 2003)

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- 6:00-6:15pm each day
- Bids
  - Hourly firm-level bids
- Demand in balancing market – assumed perfectly inelastic
- Marginal Costs for each operating fossil fuel unit
  - Fuel efficiency – average “heat rates”
  - Fuel costs – daily natural gas spot prices & monthly average coal spot prices
  - Variable O&M
  - SO<sub>2</sub> permit costs
  - Each unit’s daily capacity & day-ahead schedule

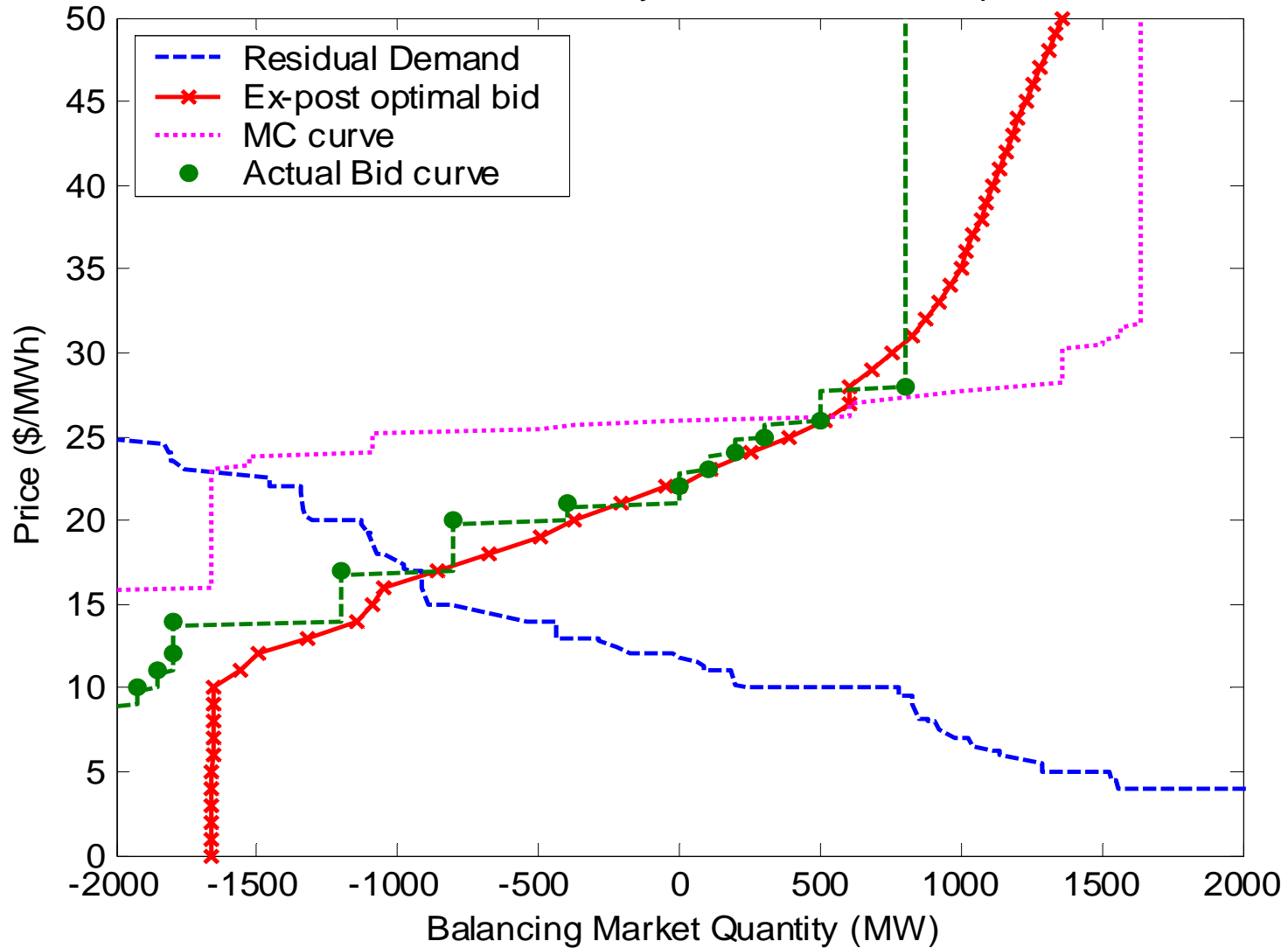
# Measuring Marginal Cost in Balancing Market

- Use coal and gas-fired generating units that are “on” and the daily capacity declaration
- Calculate how much generation from those units is already scheduled == Day-Ahead Schedule



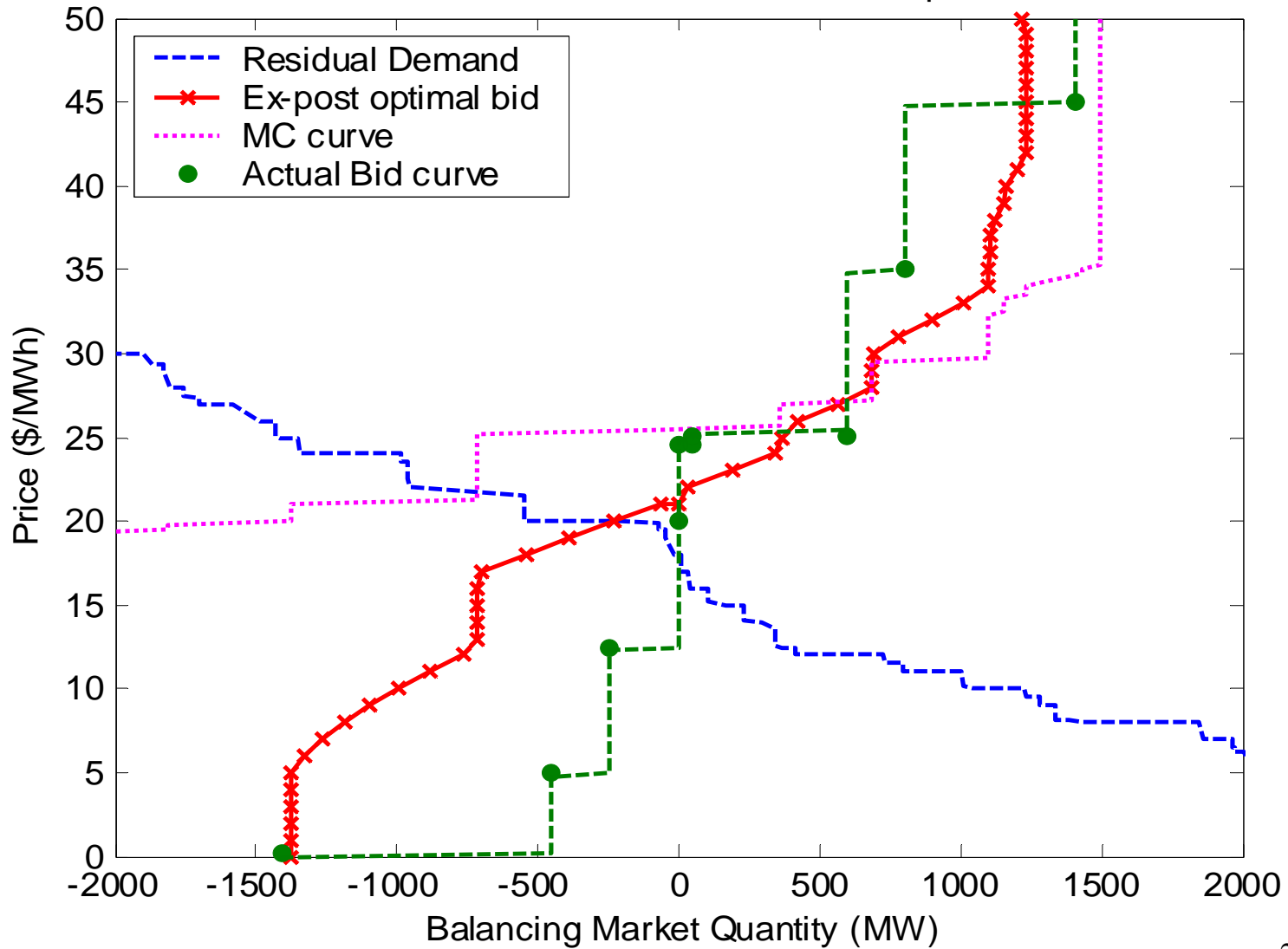
# Reliant (biggest seller) Example

Reliant on February 26, 2002 6:00-6:15pm

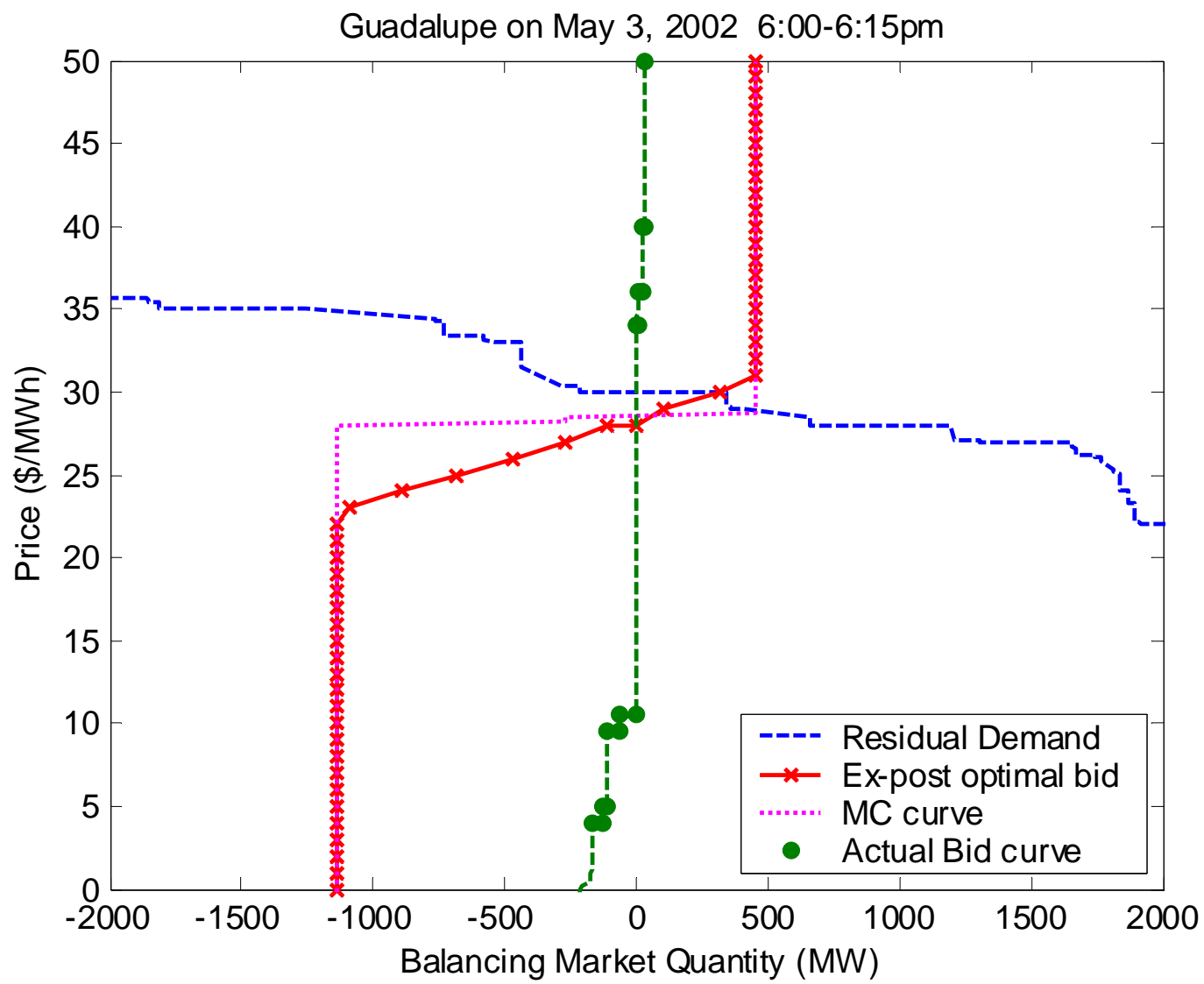


# TXU (2<sup>nd</sup> biggest seller) Example

TXU on March 6, 2002 6:00-6:15pm



# Guadalupe (small seller) Example



Firm	Percent Achieved Relative to		Producer Surplus (\$/hour)			Upper Bound of Total Profitability
	Ex-post Optimal	Naïve Best Response	Actual	Naïve Best Resp.	Ex-post Optimal	
Reliant	79%	80%	3,422	4,268	4,333	98%
Brownsville PUB	50%	50%	173	343	343	88%
City of Bryan	45%	45%	221	488	488	85%
Tenaska Gateway Partners	41%	41%	456	1,111	1,115	88%
TXU	39%	41%	1,243	3,056	3,159	97%
Calpine Corp	37%	38%	820	2,168	2,214	91%
Denton Municipal Electric	35%	35%	11	31	31	98%
Ingleside Cogeneration	31%	31%	171	541	541	79%
City of Austin	30%	31%	581	1,889	1,907	84%
Rio Nogales LP	28%	28%	109	393	393	93%
Lower Colorado River Auth	25%	25%	367	1,471	1,488	88%
City of San Antonio	23%	24%	290	1,221	1,241	90%
Gregory Power Partners	20%	20%	143	720	722	82%
Midlothian Energy	17%	17%	171	1,016	1,024	86%
Cogen Lyondell Inc	16%	16%	408	2,523	2,523	67%
Tractebel Power Inc	16%	16%	127	795	795	79%
Brazos Electric Power Coop	15%	15%	101	676	677	79%
Lamar Power Partners	15%	15%	266	1,800	1,808	79%
Mirant Wichita Falls	14%	14%	16	114	114	83%
BP Energy	14%	14%	134	993	994	80%
City of Garland	13%	13%	128	1,018	1,019	80%
Hays Energy	8%	8%	64	775	777	82%
West Texas Utilities	8%	8%	132	1,635	1,635	82%
Central Power & Light	8%	8%	185	2,375	2,407	80%
Guadalupe Power Partners	6%	6%	140	2,356	2,380	77%



PSERC

Incumbent Utility

Municipal Utility

Merchant Generator

Cooperative

# What the Traders Say about Suboptimal Bidding

1. Lack of sophistication at beginning of market
  - Some firms' bidders have no trading experience; are employees brought over from generation & distribution
2. Heuristics
  - Most don't think in terms of "residual demand"
3. Newer generators
  - If a unit has debt to pay off, bidders follow a formula of % markup to add
4. TXU
  - "old school" – would prefer to serve it's customers with own expensive generation rather than buy cheaper power from market
5. Small players (e.g. munis)
  - "scared of market" – afraid of being short w/ high prices

# Possible Explanations for Deviations from Benchmarks

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1. Unmeasured “adjustment costs”
2. Transmission constraints
3. Collusion / dynamic pricing
4. Type of firm
5. Stakes matter

# Adjustment Costs?

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1. Flexible gas-fired units often are marginal
  - 70-90% of time for firms serving as own bidders
2. “Bid-ask” spread smaller for firms closer to benchmark
  - Decreases over time for higher-performing firms

Table 5: Characteristics of Bid Functions By Percent Achieved

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Firm	Percent Achieved	Mean Bid Points	Mean Bid-Ask Spread (\$/MWh)
Reliant	79%	22.2	\$2.06
City of Bryan	45%	6.5	\$22.58
TXU	39%	12.6	\$20.60
Calpine Corp	37%	7.5	\$12.55
City of Austin	30%	10.0	\$25.92
Lower Colorado River Authority	25%	9.1	\$25.98
City of Garland	13%	6.1	\$20.32
South Texas Electric Coop	3%	3.7	\$68.66

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# Transmission Constraints?

- Does bidding strategy from congested hours spillover into uncongested hours?

Table 6: Relationship Between Profitability and Transmission Congestion

Dependent Variable: Monthly <i>PercentAchieved</i> by Firm <i>i</i>		
	All Firms	Own Bidders
Pct Intervals Congested	-0.16 (0.09)	-0.17 (0.14)
Volume Optimal Output (GWh)	0.34 (0.21)	0.09 (0.25)
Monthly Fraction DEC	-0.05 (0.06)	0.03 (0.11)
R-squared	0.48	0.47

Model includes firm fixed effects.

Robust standard errors in parentheses.

Note: *PercentAchieved* is the monthly fraction of potential profits achieved relative to not bidding, defined in section 4.2.



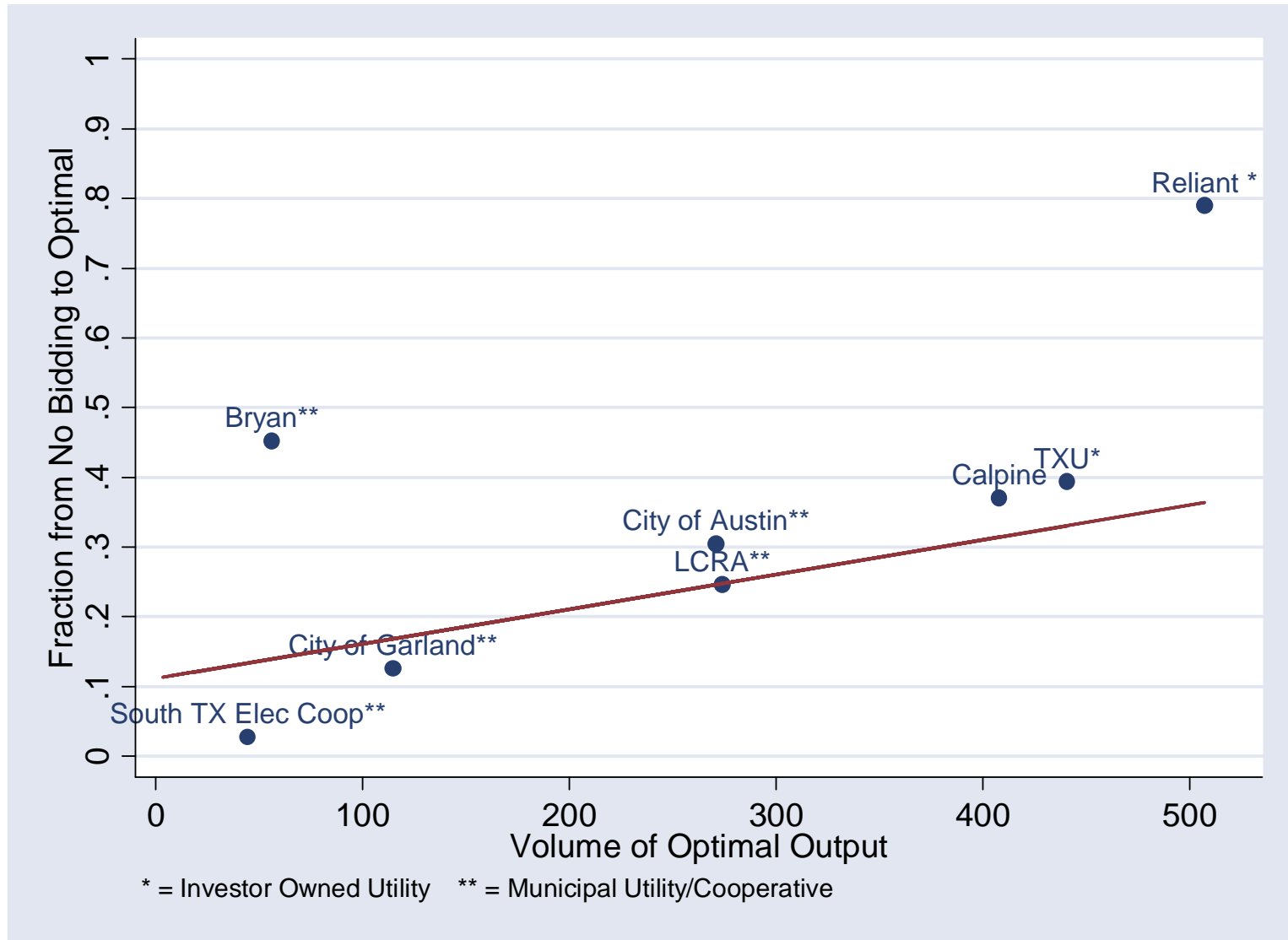
- 1 std dev increase in percent congestion → only 3% ↓Pct Achieved

# Collusion?

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- Collusion not consistent with large bid-ask spreads
  - Collusion  $\rightarrow$  smaller sales than ex-post optimal
  - Bid-ask spread  $\rightarrow$  no sales
- Would be small(!) players - unlikely

# Do Stakes Matter?



# Efficiency Losses from Observed Bidding Behavior

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- Which source of inefficiency is larger?
  - Exercise of market power by large firms?
  - Bidding “to avoid the market” by “unsophisticated” firms?

Bidding Counterfactual	Average Production Cost
Actual Bids for all firms	\$29,874
“Strategic” firms Bid MC, Others Bid Actual	\$28,671
All Firms Bid MC (Vickrey auction)	\$23,571
Total Efficiency Losses	\$6,303
“Strategic Bidders”	\$1,203
“Non-Strategic Bidders”	\$5,100

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- Total efficiency loss = **27%**
- Fraction “strategic” = 19%    **Fraction “unsophisticated”=81%!!**

# Implications for Market Design

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- Production inefficiencies arise from both:
  - Sophistication (“market power”)
  - and lack of sophistication (“avoid the market”)
- More participation by small players → less market power for large players
- Market monitor should concern itself with:
  - Bidding by smaller players
  - Market power on DEC side
- Market design
  - If strategic complexity imposes large participation costs, may wish to choose mechanisms with dominant strategy equilibrium (e.g. Vickrey auction)

For more details, see:

[http://econweb.tamu.edu/puller/AcadDocs/Hortacsu\\_Puller.pdf](http://econweb.tamu.edu/puller/AcadDocs/Hortacsu_Puller.pdf)

Thank You!