Market Power and Mitigation in Deregulated Electricity Markets

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Talk Outline

The Problem: Competitive markets are free, but not all free markets are competitive. Is there a way to make electricity markets free and competitive?

- Issues in measuring market structure and building a better metric for electric power markets (pivotal suppliers)
- Market structure in CAISO, PJM, NYISO
- Mitigation options and costs: one solution will not work for all electric power systems
- Conclusions and extensions

Measuring Market Structure

Conventional metrics of market structure are concentration-based, looking at firm size relative to other firms.

Herfindahl-Hirschman Index (HHI) is the sum of the squared market shares of all firms in the market. The HHI ranges from zero (perfect competition) to 10,000 (monopoly).

System	HHI
California	664
PJM	1,160
NYISO	637

The DOJ threshold for a "concentrated" market is 1,800. Was the California power crisis really the result of a competitive market?

Problems with Concentration Measures

Concentration measures such as the HHI fail to accurately describe the structure of electricity markets because they fail to account for the special properties of electricity as a commodity.

Nonstorability ? Demand and supply must match at every moment. Market structure is a function of firm size, system size, and demand at every moment.

Example of a "pivotal" monopolist

Suppose that:

• Total generation capacity is 100 MW;

• Firm *M* controls 18 MW;

• The ISO announces that it seeks to buy 90 MW;

Results:

• Firm *M* knows that it has monopoly power, and the implied HHI for this market is 10,000;

• If every other firm in the market had less than 1% of market share, the conventional HHI would be 324.

We can repeat this example for a "pivotal" duopoly, and so on…

Calculation of the Pivotal Firm Duration Curve (PFDC):

Step 1: Calculate the “residual demand” for each hour (demand less imports and committed/must-run power)

Step 2: Calculate the “residual supply” for each hour (system capacity less committed/must-run power)

Step 3: Calculate the system surplus capacity for each hour; this is simply residual supply less residual demand

Step 4: Compare the system surplus capacity to the capacities of individual generators (check for pivotal monopolies, duopolies, etc.)

Calculating the Pivotal Firm Duration Curve

- Pivotal firm duration curves are calculated for CAISO, PJM, and NYISO (selections based on amount of available data).
- Nuclear generation is inflexible (must-run), so it is excluded from the calculation.
- No long-term contracts in California; no data on contracts in PJM and NYISO, so market power is probably overstated in PJM and NYISO

Data Sources

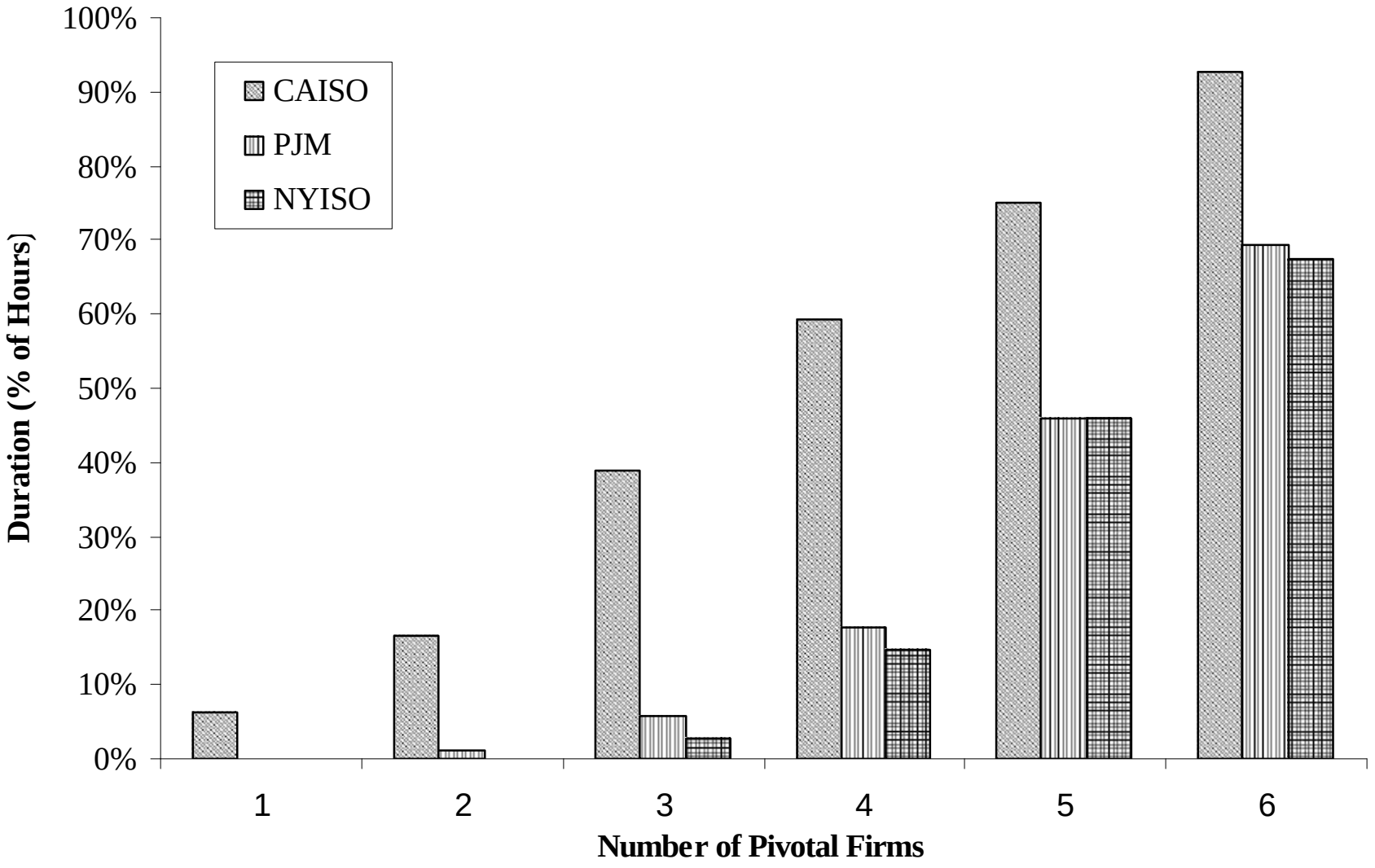
	Generation Capacity	System Load[a]	Imports
California	CAISO, EIA, EPA	CAISO OASIS[b]	CAISO OASIS
PJM	EIA,EPA	PJM OASIS	PJM OASIS
New York	EIA, EPA	NYISO	NYISO

a. System Load includes Ancillary Services. AS not available for NYISO.

b. OASIS = Open Access Same-time Information System

Pivotal Supplier Duration Curves for NYISO, PJM, CAISO

(June 2000 – June 2001, excludes nuclear, and geothermal for CAISO)



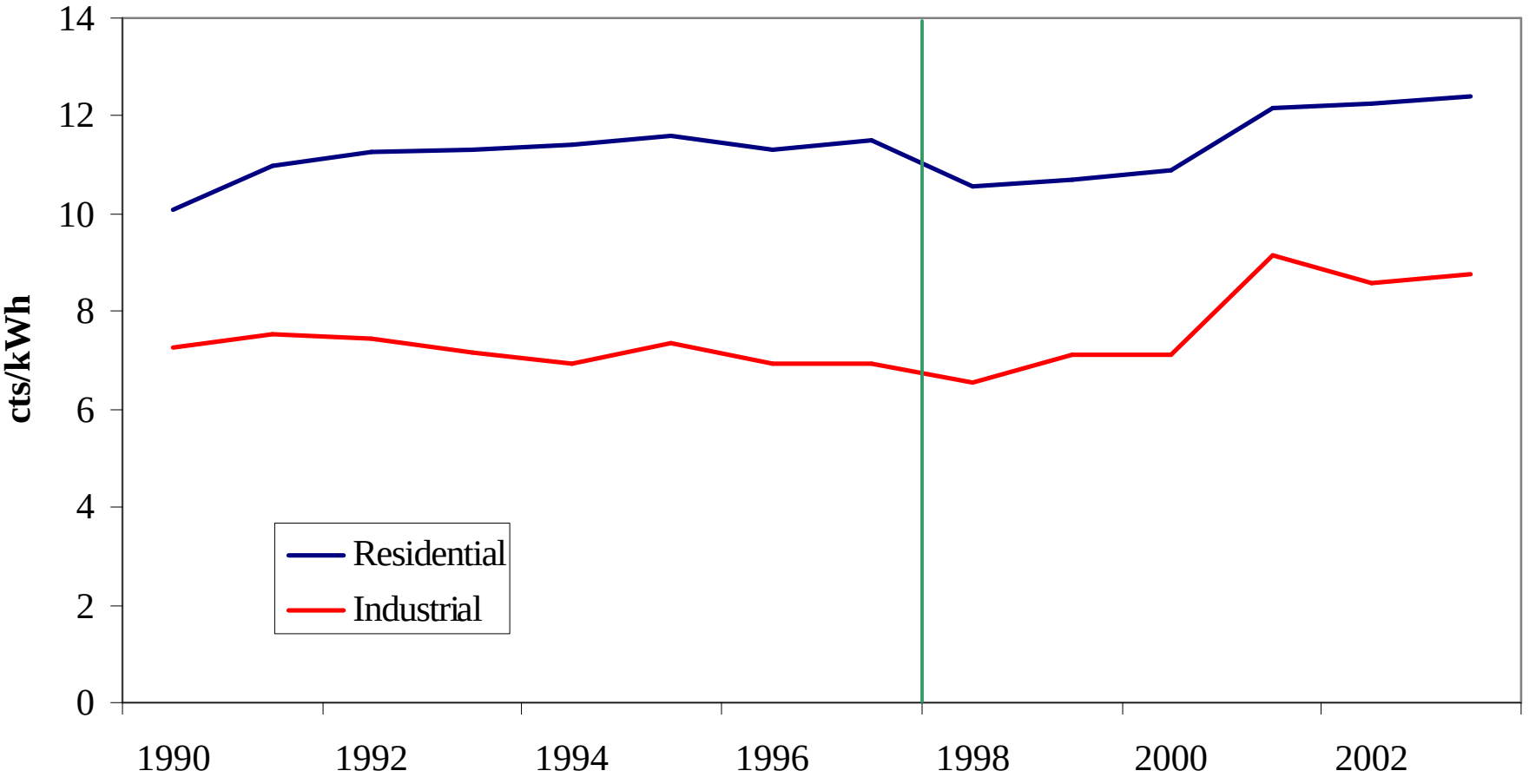
Curtailing Market Power

Eliminate the power to raise price by withholding capacity:

A. Regulate price during high demand
B. Increase generation capacity
C. Increase transmission capacity
D. Increase demand response
E. Lower firm size: Divest assets
F. Long-Term contracts

Benefits to Deregulation?

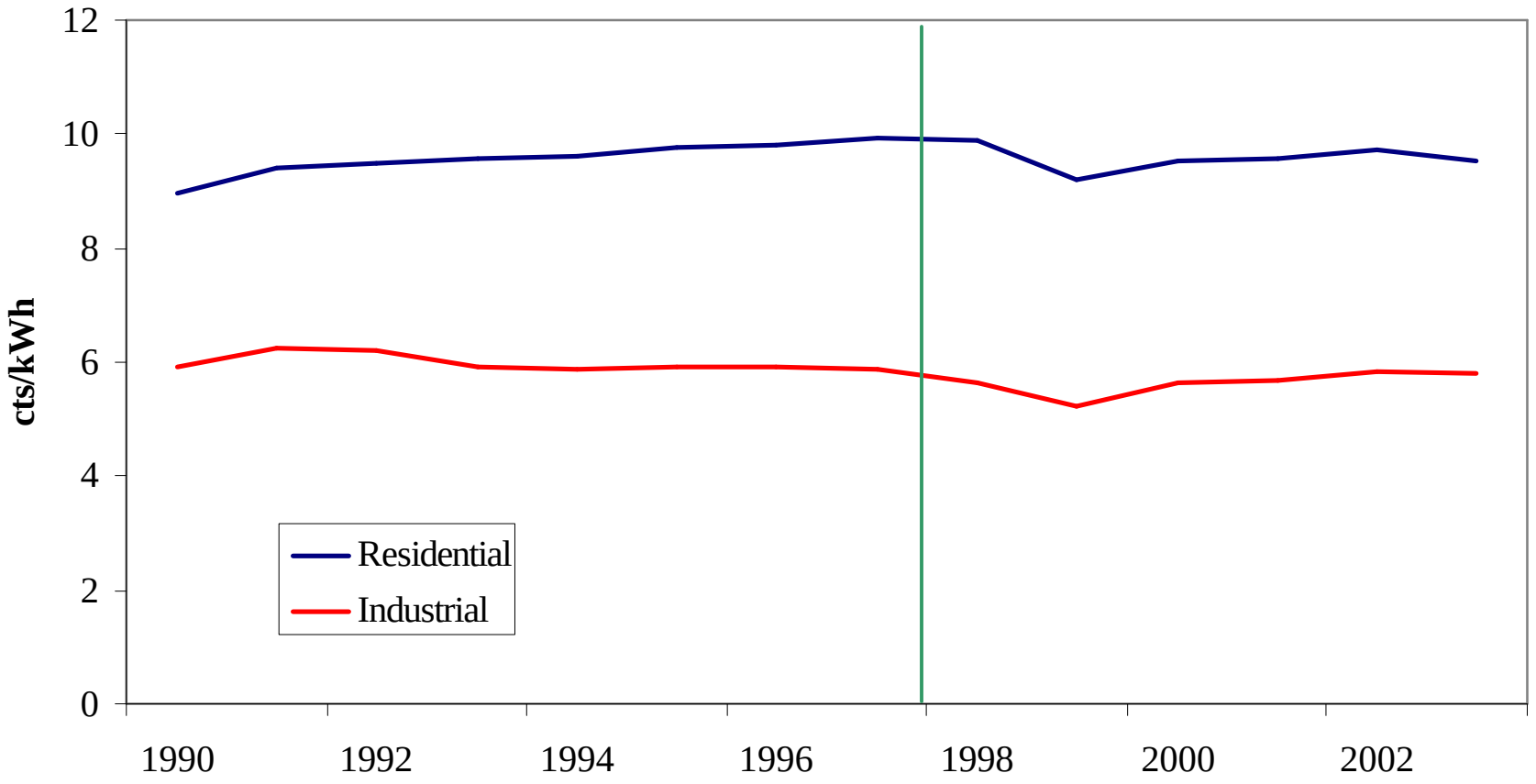
California: No-brainer, prices have risen since deregulation



Source: Average retail prices from EIA.

Benefits to Deregulation?

Pennsylvania: Prices slightly lower than before deregulation, but also a retail price freeze in effect through December ‘03



Source: Average retail prices from EIA.

Regulate Price When Demand is High

1. Standard Market Design (SMD): “Hard” price cap during all hours, with price = average variable cost (AVC) during hours of high prices.
    i. Competitive firms can’t recover capital costs, and marginal firms may not fully cover variable cost
    ii. Requires regulators to perform audits, approval of new capacity…tantamount to re-regulation
2. Supplier Margin Assessment (SMA): Revoke the ability of pivotal suppliers to charge market-based prices when they are demonstrably pivotal.
    i. Revocation of market-based ratemaking applies to an entire month or year in which a supplier is pivotal, even if pivotal status only lasts for a small number of hours.
    ii. Does not account for the possibility of pivotal oligopoly

Increase Generation Capacity

- Will do the job, but raises costs
- Example: Build gas turbines at $600/kW to mitigate pivotal duopoly. California had pivotal duopolies 16% of the time in 2000, amounting to 1,400 hours. Pivotal duopoly owns 8.4 GW of generation in California.

  Capital costs: 10-year payback at 10% ? annual capital costs of $81/kW.

  Capacity only needed for 1,400 hours ? marginal cost of

  10.7 cts/kWh to mitigate pivotal duopoly.

- Offset some of the costs with reserve benefit?

  Replacing a 8,000 heat rate plant with a 12,000 heat rate plant will offset some fuel costs, but also has higher capital costs.

Increase Generation Capacity

Pivotal Group Size		California		PJM		NYISO	
	System Capacity (GW)	**54**		**60**		**38**	
	Average Retail Price ($/kWh)	**$0.12**		**$0.07**		**$0.11**	
	Capital Cost ($/kW)	**$600**	**$1,200**	**$600**	**$1,200**	**$600**	**$1,200**
1	Additional Capacity Needed (GW)	4.9		0.0		0.0	
	Average Mitigation Cost (cts/kWh)	48.36	96.71	0.00	0.00	0.00	0.00
	Cost Increase (%)	*403.0%*	*805.9%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
2	Additional Capacity Needed (GW)	8.4		15.7		0.0	
	Average Mitigation Cost (cts/kWh)	10.67	21.34	83.36	166.72	0.00	0.00
	Cost Increase (%)	*88.9%*	*177.8%*	*1190.9%*	*2381.7%*	*0.0%*	*0.0%*
3	Additional Capacity Needed (GW)	11.7		21.1		14.7	
	Average Mitigation Cost (cts/kWh)	3.24	6.48	12.23	24.46	37.83	75.66
	Cost Increase (%)	*27.0%*	*54.0%*	*174.7%*	*349.4%*	*343.9%*	*687.8%*
4	Additional Capacity Needed (GW)	14.9		25.2		17.6	
	Average Mitigation Cost (cts/kWh)	1.67	3.35	3.33	6.65	5.72	11.44
	Cost Increase (%)	*14.0%*	*27.9%*	*47.5%*	*95.1%*	*52.0%*	*104.0%*
5	Additional Capacity Needed (GW)	17.8		28.8		20.1	
	Average Mitigation Cost (cts/kWh)	1.10	2.21	1.12	2.23	1.60	3.19
	Cost Increase (%)	*9.2%*	*18.4%*	*16.0%*	*31.9%*	*14.5%*	*29.0%*
6	Additional Capacity Needed (GW)	20.7		32.4		22.4	
	Average Mitigation Cost (cts/kWh)	0.77	1.54	0.66	1.32	0.98	1.95
	Cost Increase (%)	*6.4%*	*12.8%*	*9.4%*	*18.8%*	*8.9%*	*17.8%*

Assumptions: 10% discount rate (CAPM), all new generation is gas-fired with a 30-year economic life, capacity is on standby during hours with pivotal suppliers.

Increasing System Capacity – New Transmission

Example: Mitigating pivotal duopoly in California (again)
Necessary capacity amounts to 10,000 MW (5,000 line-miles, including losses).
Capital cost of $0.12 million per mile ? total cost $600 million.
At 200 million MWh/year, electricity costs rise by 0.3 to 1 ct/kWh.

- Transmission is cheaper than generation, but still raises costs
- Intense political opposition to siting new lines (NIMBY)
- Transmission will only mitigate pivotal suppliers if imports are available and competitively priced

Increase Transmission Capacity

Is surplus generation capacity available elsewhere when needed?

In California/Northwest – Yes, except during drought

In East – Less likely due to coincident demand peaks

	AZ	CA	NM	OR	WA
AZ	1				
CA	0.90	1			
NM	0.93	0.80	1		
OR	-0.10	**-0.04**	0.10	1	
WA	-0.48	**-0.41**	-0.33	0.77	1

Demand correlation matrix – Western States

	PJM	NYISO	ECAR	SERC	NEPOOL
PJM	1				
NYISO	**0.92**	1			
ECAR	**0.90**	0.78	1		
SERC	0.87	0.83	0.88	1	
NEPOOL	0.91	0.86	0.84	0.74	1

Demand correlation matrix – Eastern Interconnect

Demand Response

- For mitigation to work, demand needs to drop by at least the difference between the capacity owned by the pivotal group and the system surplus capacity.
- Can still have a monopoly with a downward-sloping demand curve
- The amount of demand response needed to mitigate pivotal groups is large, but could be effective if suppliers are pivotal in a small number of hours (pivotal duopoly occurred in PJM around 1% of hours)

Pivotal Group Size	CA Demand Response MW	CA Demand Response %	PJM Demand Response MW	PJM Demand Response %
1	4,840	12%	5,395	15%
2	3,534	10%	5,395	15%
3	3,296	10%	5,381	18%
4	3,165	12%	4,030	16%
5	2,951	12%	3,617	16%
6	2,877	13%	3,611	19%

Demand Response in Elasticity Terms

Pivotal Group Size	Price Cap In Effect	Demand Response	New Demand	Price Increase	New Price	Estimated Elasticity
1	$750	4,840	34,492	61.5	73.5	-0.17
2	$150	3,534	30,529	5.25	17.25	-0.38
3	$250	3,296	29,069	6.25	18.25	-0.33
4	$250	3,165	24,279	5.00	17	-0.44
5	$150	2,951	22,593	3.3	15.3	-0.61
6	$250	2,877	19,718	1.25	13.25	-1.55

Demand Response: From previous slide

New Demand: Load after demand response

Price Cap in Effect: California power price cap

New Price: Estimated based on average price (as a percentage of the price cap) with a given pivotal group size.

Price Increase: Premium over assumed MC = $12.

Estimated Elasticity: (? Q/? P) × (P/Q) = (Dem. Res./Pr. Inc.) × (New Pr./New Dem.)

Divestiture

- Mitigation through divestiture works by limiting plant holdings by each firm to the point where firms are no longer pivotal (or pivotal less often).
- In areas where system surplus capacity is larger, such as PJM, divestiture can completely mitigate certain-sized pivotal groups. In California, no amount of divestiture can completely eliminate pivotal oligopolies since surplus capacity is negative at peak periods.

Pivotal Groups in PJM Under Divestiture:

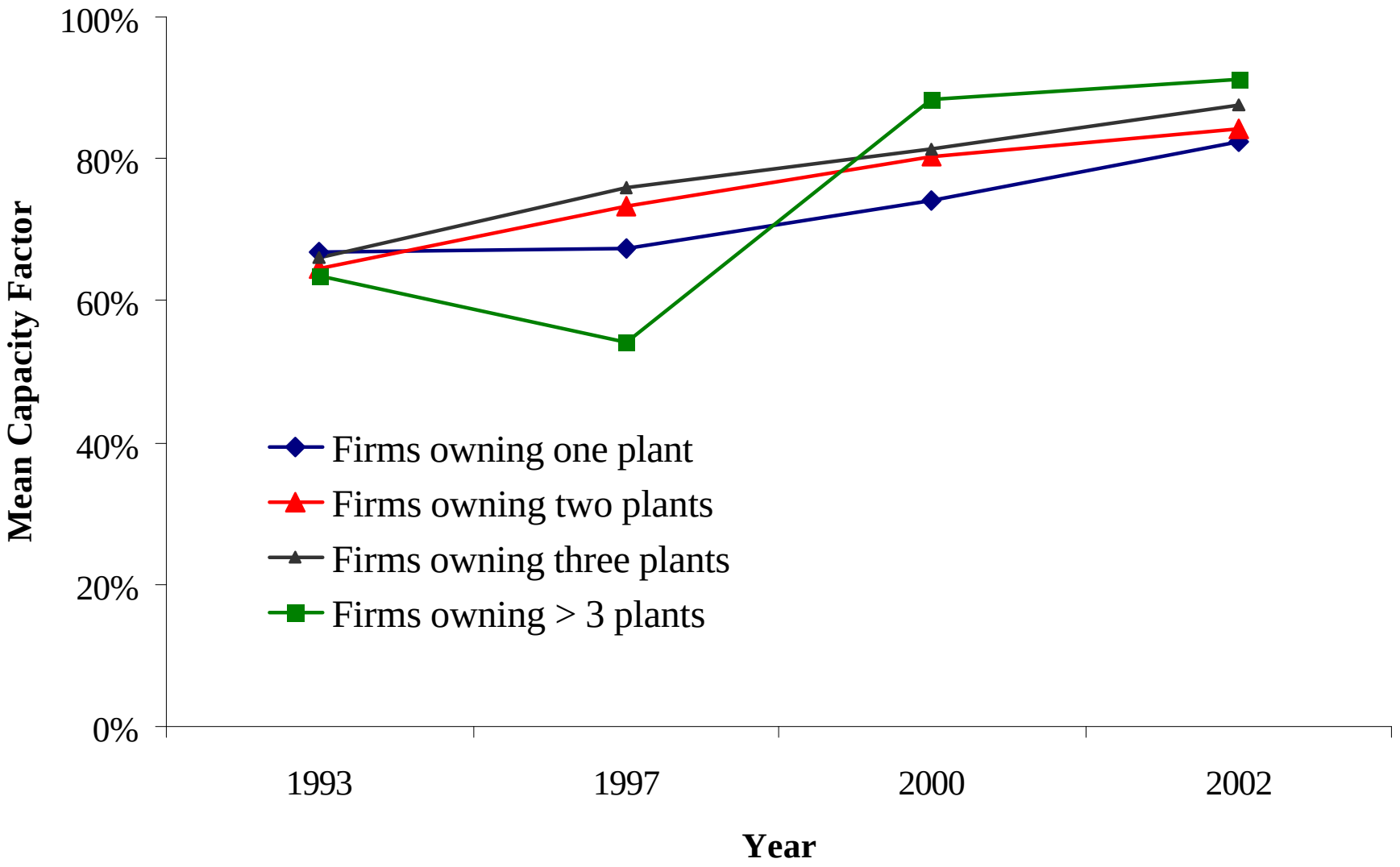
Number of Pivotal Firms	PFDC Under Capacity Ownership Limit (% Hrs.)				
	No Limit	10 GW	6 GW	4 GW	3 GW
1	0%	0%	0%	0%	0%
2	1%	1%	0%	0%	0%
3	6%	6%	2%	0%	0%
4	18%	17%	6%	1%	0%
5	46%	45%	16%	4%	1%
6	69%	69%	42%	10%	2%

Limitations of Divestiture

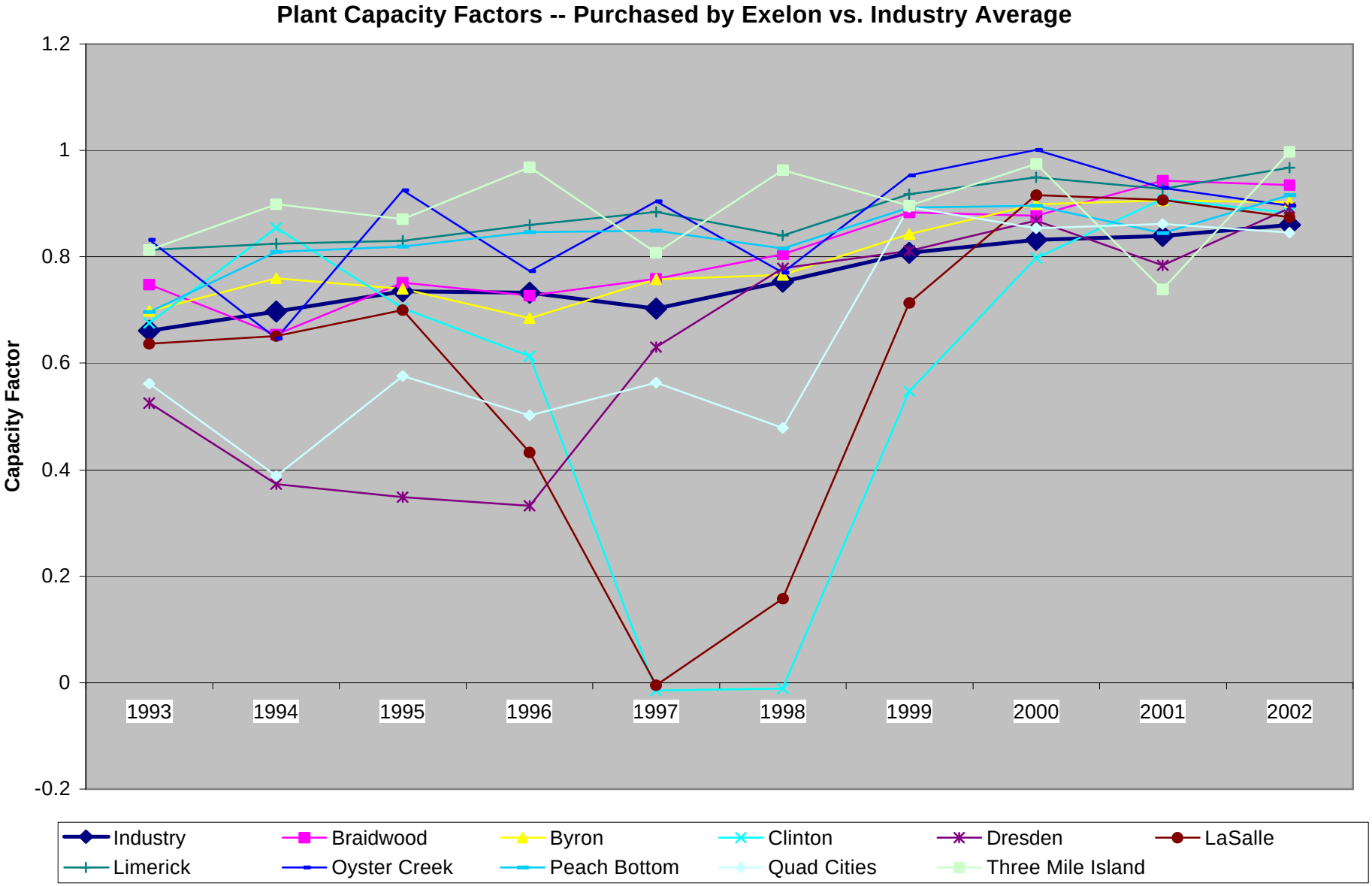
1. Economies of scale: Systems dominated by large generators are unlikely to succeed with divestiture (e.g. The largest plant in Arkansas represents 20% of the state's capacity). Ownership can be subdivided, but are there incentives for collusion among the owners? Control must also remain in the hands of a single firm.
2. Management economies of scale: Similar to economies of scope, firms may be able to employ one person to perform tasks at multiple generators (fuel purchasing, operations, etc.).

- Economies of scale are not an issue for PJM or California. The largest thermal unit in California represents less than 2% of capacity. The largest thermal unit in PJM represents 5% of capacity
- The loss of management economies is hard to measure, since we need data on power plant operations before and after divestiture. Consolidation in the nuclear industry may provide some clues – larger firms in the nuclear industry have become more efficient at a faster pace than smaller firms.

Some Evidence for Management Economies in Nuclear Generation



A Closer Look at Exelon



Long-Term Contracts

- Two motivations for long-term contracts: to reduce the amount of pivotal supply bid into spot markets, and to reduce use of the spot market in general, since repeated interactions encourage implicit collusion.
- California: Originally only limited to one hour or one day contracts. When longer contracts were permitted, prices went as high as $150/MWh.
- Long-term contracts need to give buyers a bargaining chip ("outside option"), or suppliers will wind up pivotal in the spot and contract markets! The option of building generation in place of a contract is a good candidate for an outside option. This means an active market for 20- or 30-year contracts.
- Incentives of the buyer and seller need to coincide. The structure of the "optimal contract" is still an open question. Moral hazard problems in plant maintenance, fuel purchase, construction, staffing. Need to pay suppliers extra to incite the desired level of performance.

Conclusion

1. Concentration measures such as the HHI are poor descriptors of electricity market structure. FERC SMA corrects this, but is overly harsh and needs to account for pivotal oligopoly.
2. Effective market-power mitigation in one system may be costly and ineffective in another system.
    - New transmission from the NW could be relatively inexpensive and beneficial for CA if prices were competitive; less appealing for PJM and NY since peak demands are coincident.
    - Divestiture is more appealing for PJM than California; cutting the largest firms in half would eliminate pivotal monopolies and duopolies. No reasonable divestiture plan in California would be as successful.
3. Do the costs of mitigating pivotal suppliers outweigh efficiency gains from deregulation?

- In California, Deregulation has created inefficiencies and electricity costs have risen. In PJM, prices have dropped by 1 ct/kWh (partially due to price caps). This is still lower than most measured costs of mitigating market power.

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