WHOLESALE ELECTRICITY MARKET DEVELOPMENTS IN THE U.S.

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MIT CEEPR

Cambridge-MIT Institute Electricity Project

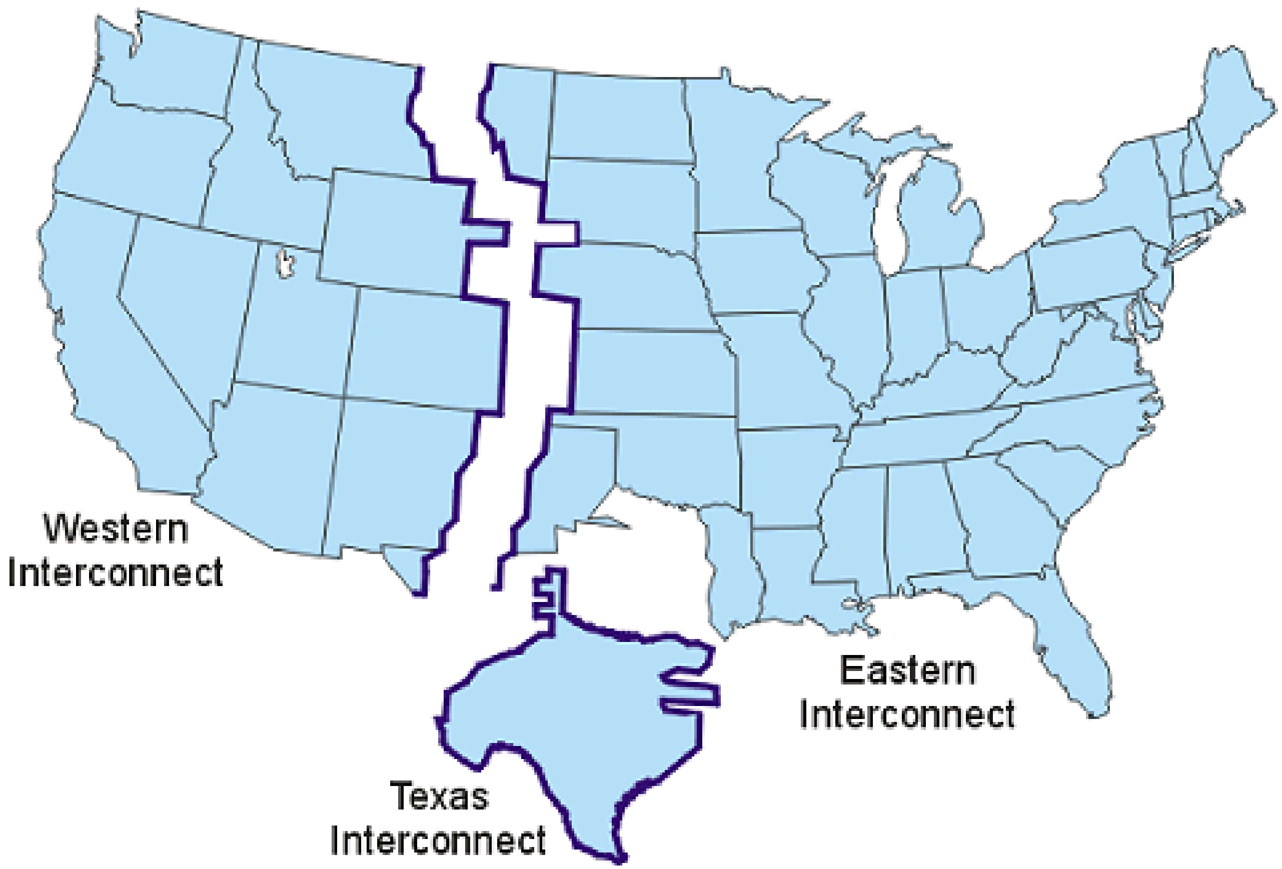
THE UNITED STATES

- Big country
- 50 states
- Diverse energy resources and costs
- Electric power sector organization and regulation was historically primarily the responsibility of the states
- Federal (FERC) historical role very small and its statutory authority modest
- Liberalization involves major increase of federal over state regulatory authority, creating state-federal tensions
- No broad national commitment to liberalization of the electricity sector. Very diverse regional views
- California mess in 2000-2001 slowed down reforms in other states
- August 2003 blackout is being used by opponents of further reform

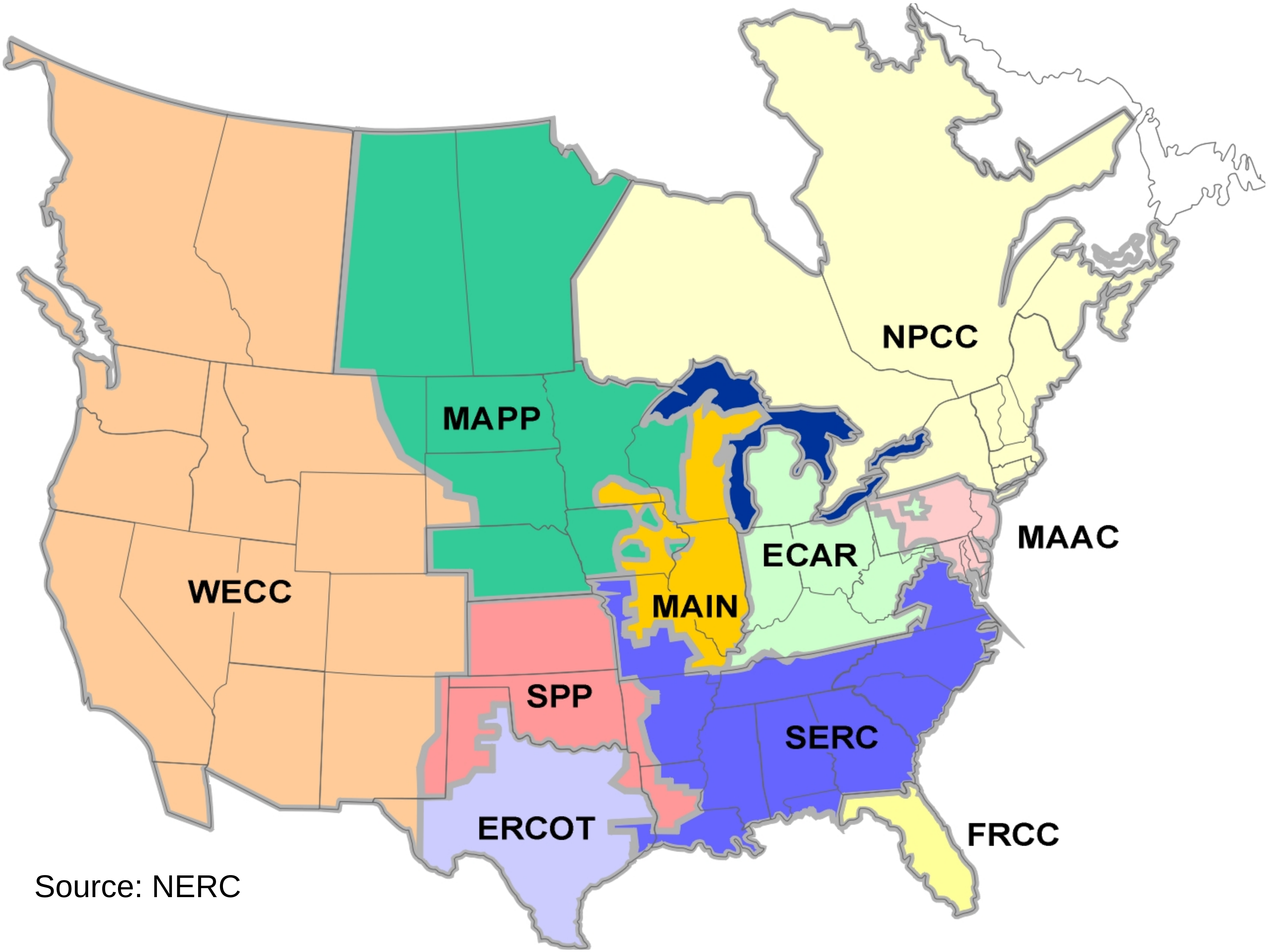
U.S. REGULATORY FRAMEWORK

- Federal: FERC (Federal Power Act of 1935)
  - Wholesale power transactions (not sales to end-users)
  - Interstate “unbundled” transmission access and pricing
  - Utility mergers
  - Market-based pricing authority (under J&R standard)
  - Has used limited statutory authority aggressively
- States: 49 State PUCs (+DC)
  - Local distribution franchises
  - Retail competition/procurement framework
  - Utility organization (Vertical integration)
  - Retail power prices and supporting costs (G +T+G)
  - Transmission investment approvals
  - Full unbundling of T&D for retail sales

North American Electric Power Grids



Source: NERC

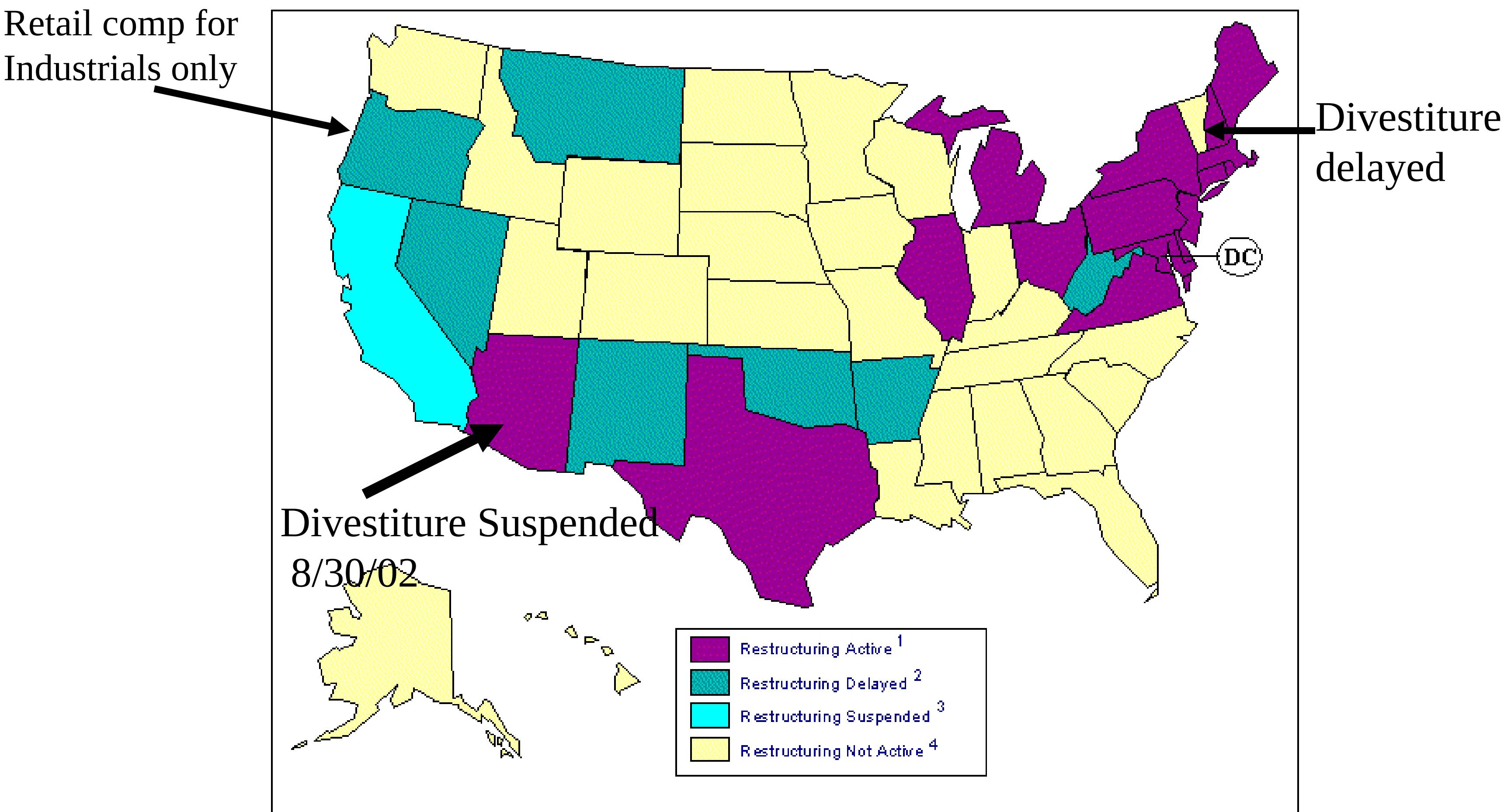


Source: NERC

LIBERALIZATION MILESTONES

- Energy Policy Act of 1992
  - FERC authority over transmission service expanded
  - Unregulated generating plants supported (EWG)
- FERC Order 888/889 (1996)
  - Open Access Transmission Tariffs
  - OASIS
- FERC Order 2000 (December 1999)
  - Formation of Regional Transmission Operators (RTOs)
  - Basic Wholesale Market and Transmission Pricing Principles
- Standard Market Design (SMD) Proposal (2002)
  - “PJM” for All
- Wholesale Market Platform White Paper (2003)
  - FERC Backs off SMD and returns to Order 2000
- Generator Interconnection Rules (2003)

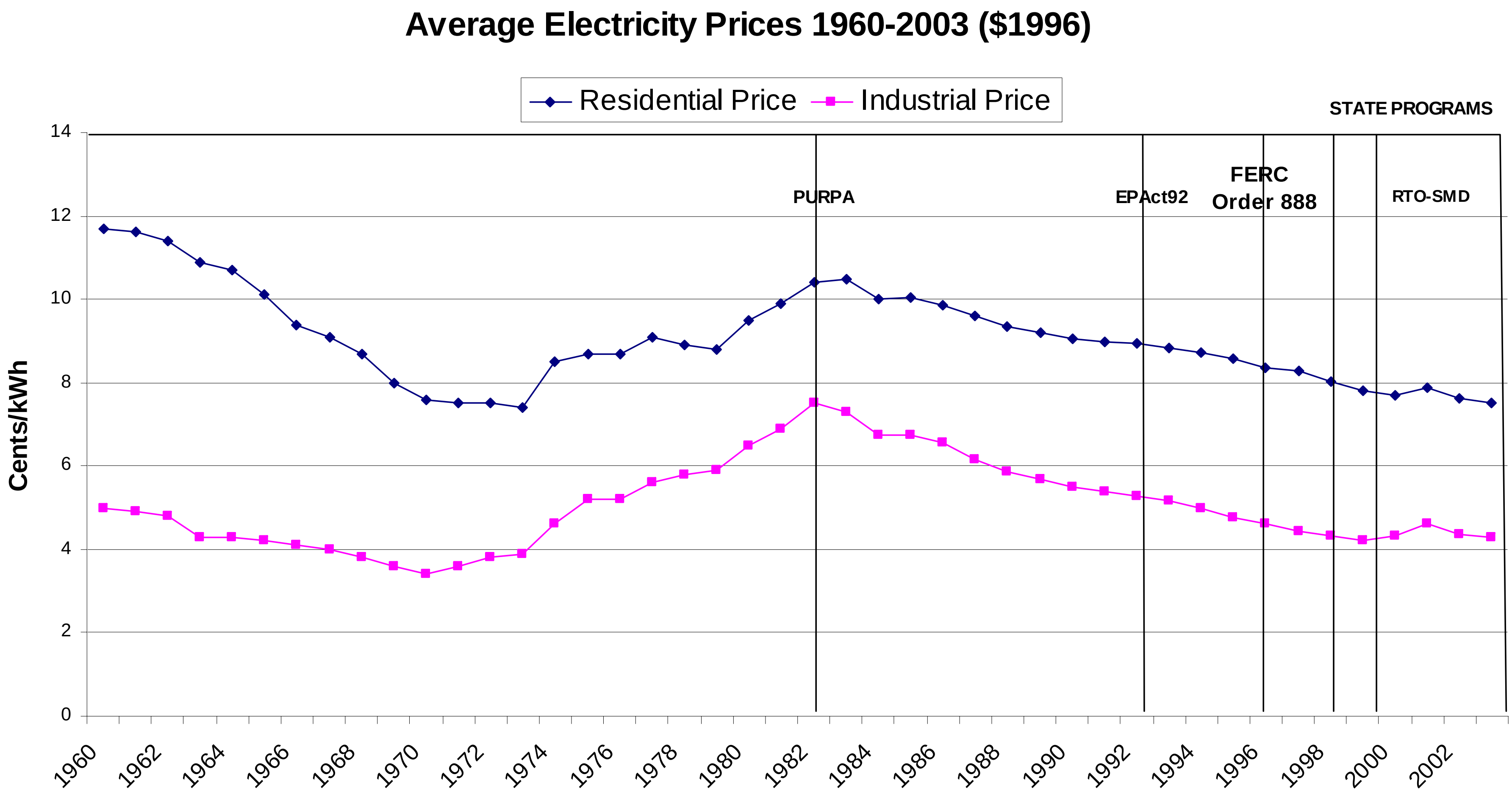
STATUS OF COMPREHENSIVE RESTRUCTURING PROGRAMS: STATES



Source: EIA

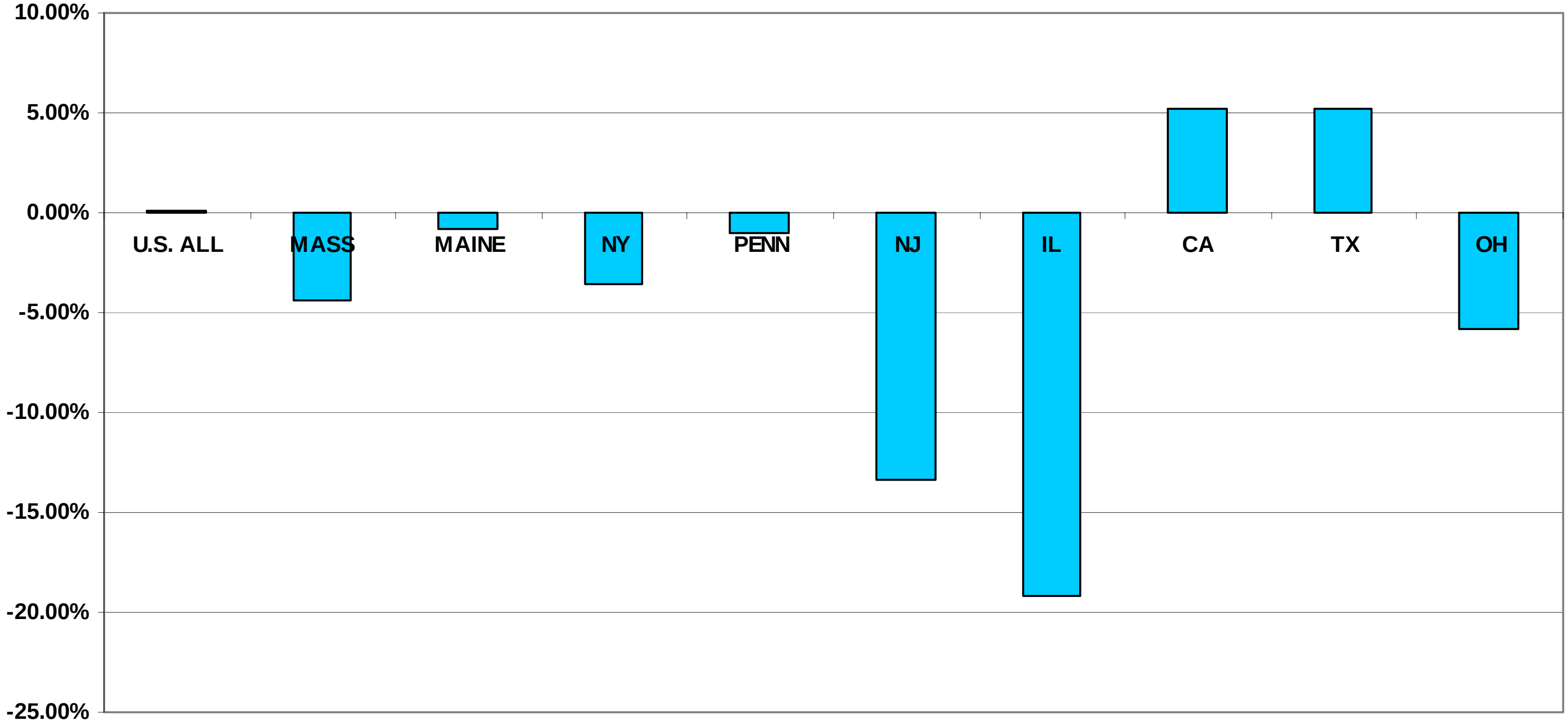
U.S. WHOLESALE MARKET CHANGES

- About 650,000 Mw of U.S. generating capacity in 1996 (75% IOU), almost all of it regulated and integrated with T&D
- 100,000 Mw divested and deregulated by 2003
- 85,000 Mw transferred to unregulated affiliates by 2003
- 175,000 Mw of new generating capacity (80% merchant) added between 2000 and 2003
- Large increase in wholesale trade. About 35% of electricity is produced by unregulated generators today (45% of IOU generation)
- Wholesale market prices have declined after controlling for fuel price changes


Average Electricity Prices 1960-2003 ($1996)
Residential Price
Industrial Price
STATE PROGRAMS
PURPA
EPAct92
FERC
Order 888
RTO-SMD
Cents/kWh
0
2
4
6
8
10
12
14
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002

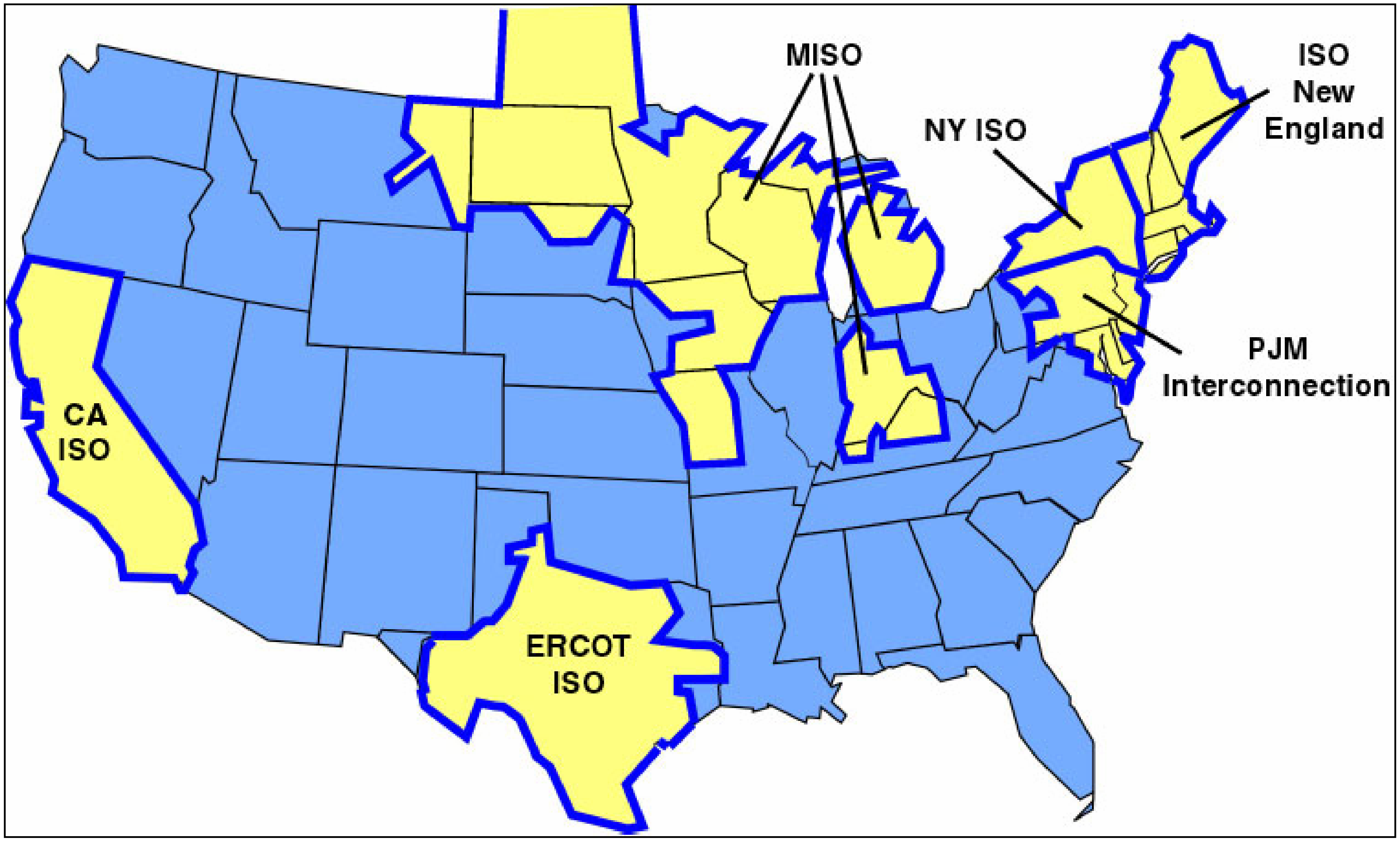
Source: EIA

% Change in Nominal Residential Retail Price (1995-2002)



LIBERALIZATION IS NOW MOVING FORWARD SLOWLY

- Restructuring and competition at wholesale and retail levels is still in transition and varies widely from state to state and region to region
- Development of important wholesale market institutions is incomplete in large portions of the country
- No comprehensive Federal restructuring, competition and deregulation initiatives have been passed by Congress
- States have taken their own individual paths with FERC trying to knit together consistent transmission access, pricing and wholesale market rules
- Vertically integrated regulated monopoly model and competitive models are trying to operate simultaneously but very uneasily on the same physical networks
- Incompatible market and regulatory structures operating on the same physical electric power network creates very significant challenges!

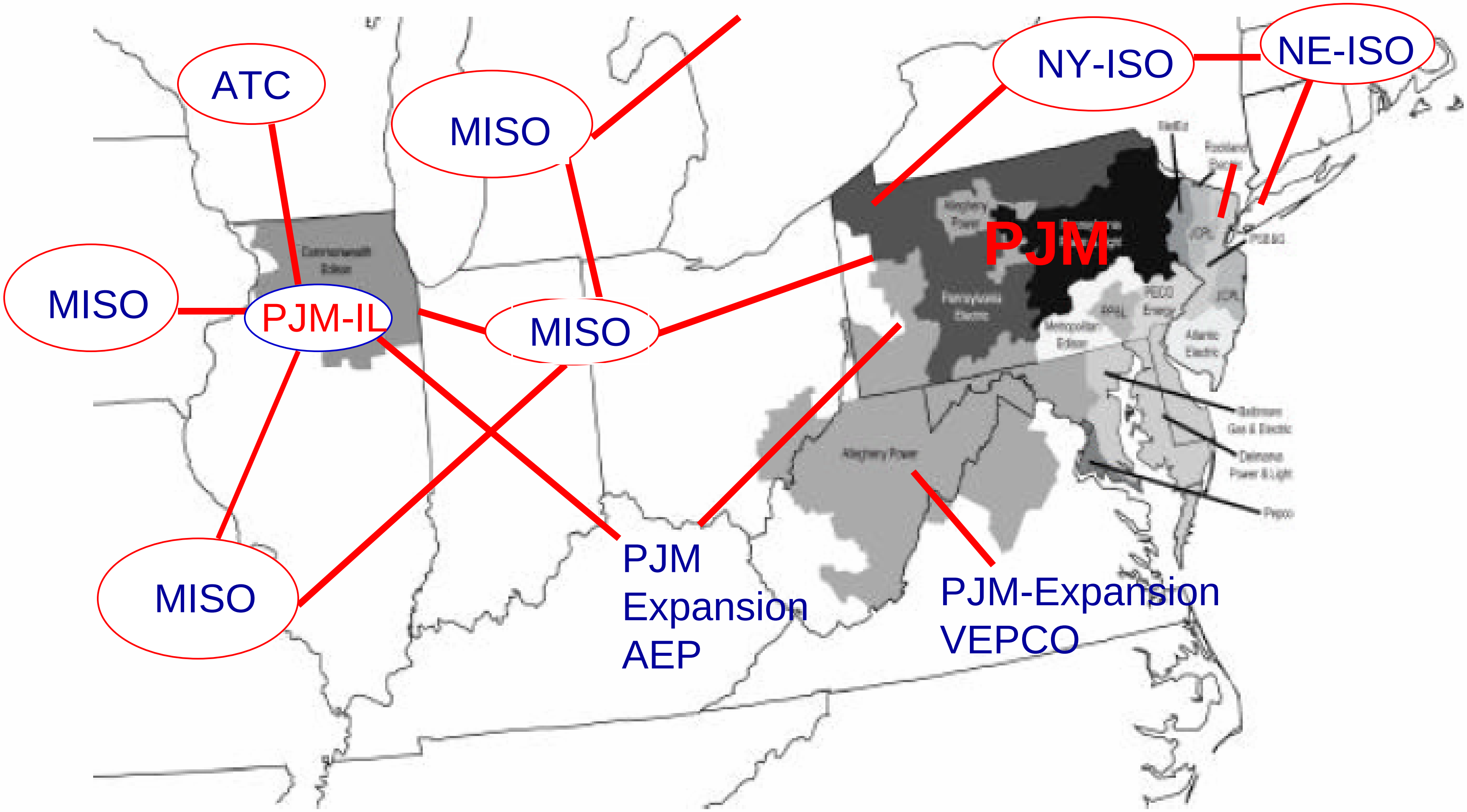

MISO
ISO
New
England
NY ISO
PJM
Interconnection
CA
ISO
ERCOT
ISO

Source: EIA

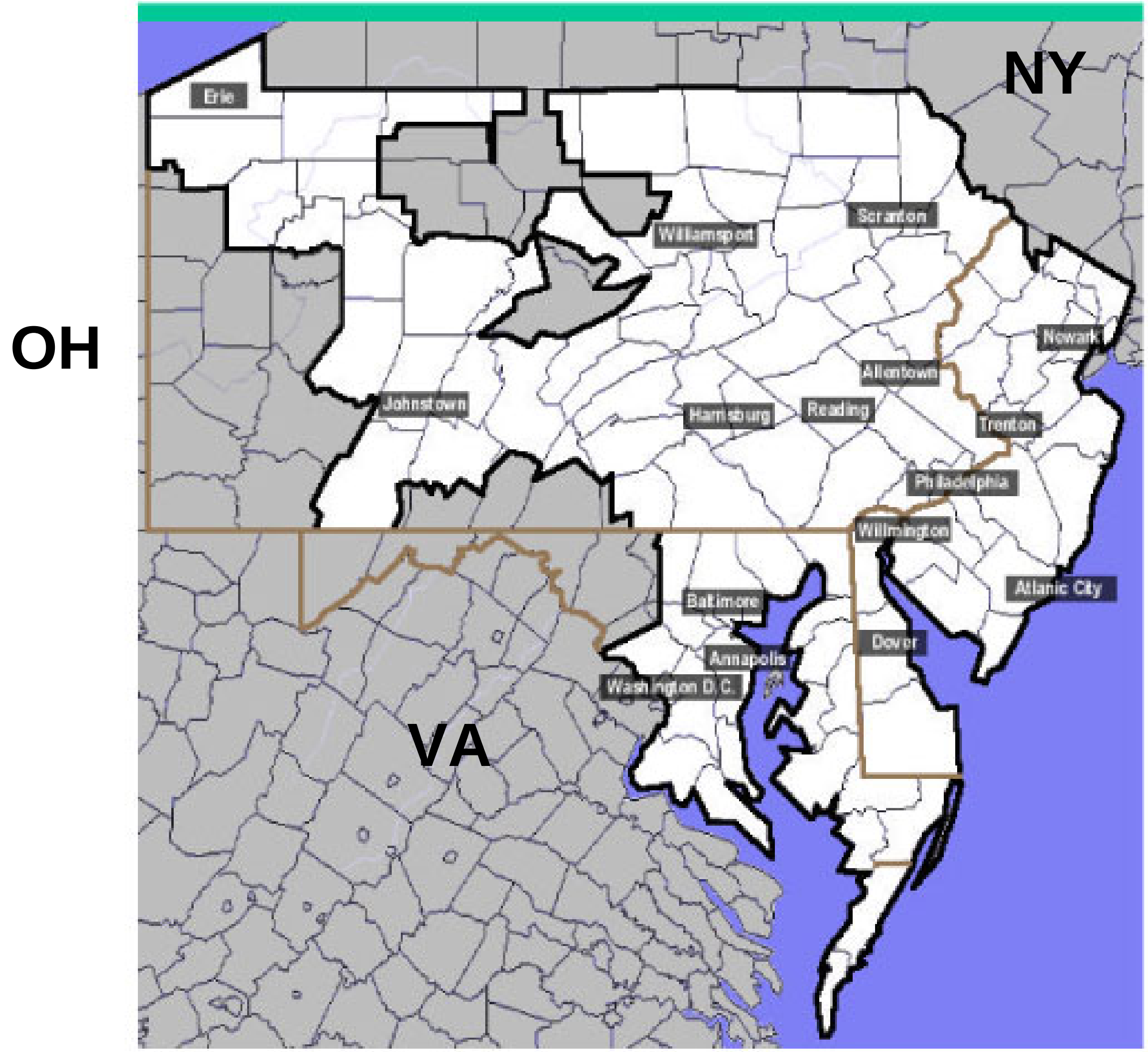
FOCUS ON THE NORTHEASTERN MARKETS

- New England, New York and PJM
- Best articulations of FERC’s RTO and SMD visions
- Retail competition in all states but Vermont
- Continued state commitments to restructuring and competition
- Several years of experience
- California and MISO will adopt similar market designs
- PJM expanding West to include portions of Ohio, West Virginia, Indiana, and Virginia as well as Northern Illinoid

PJM RTO 2004
AND INTERCONNECTIONS

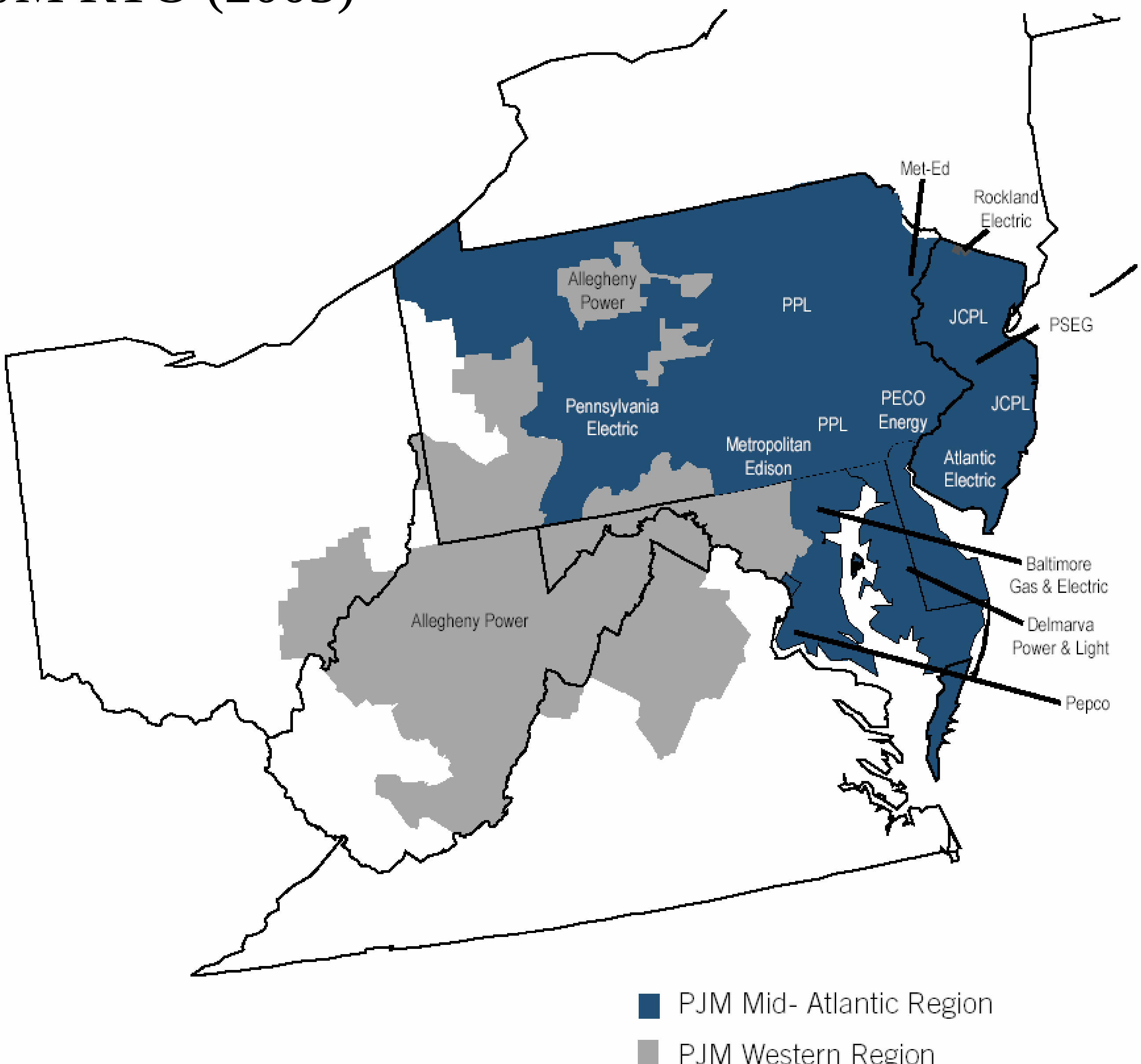


PJM Control Area 1998



Source: PJM

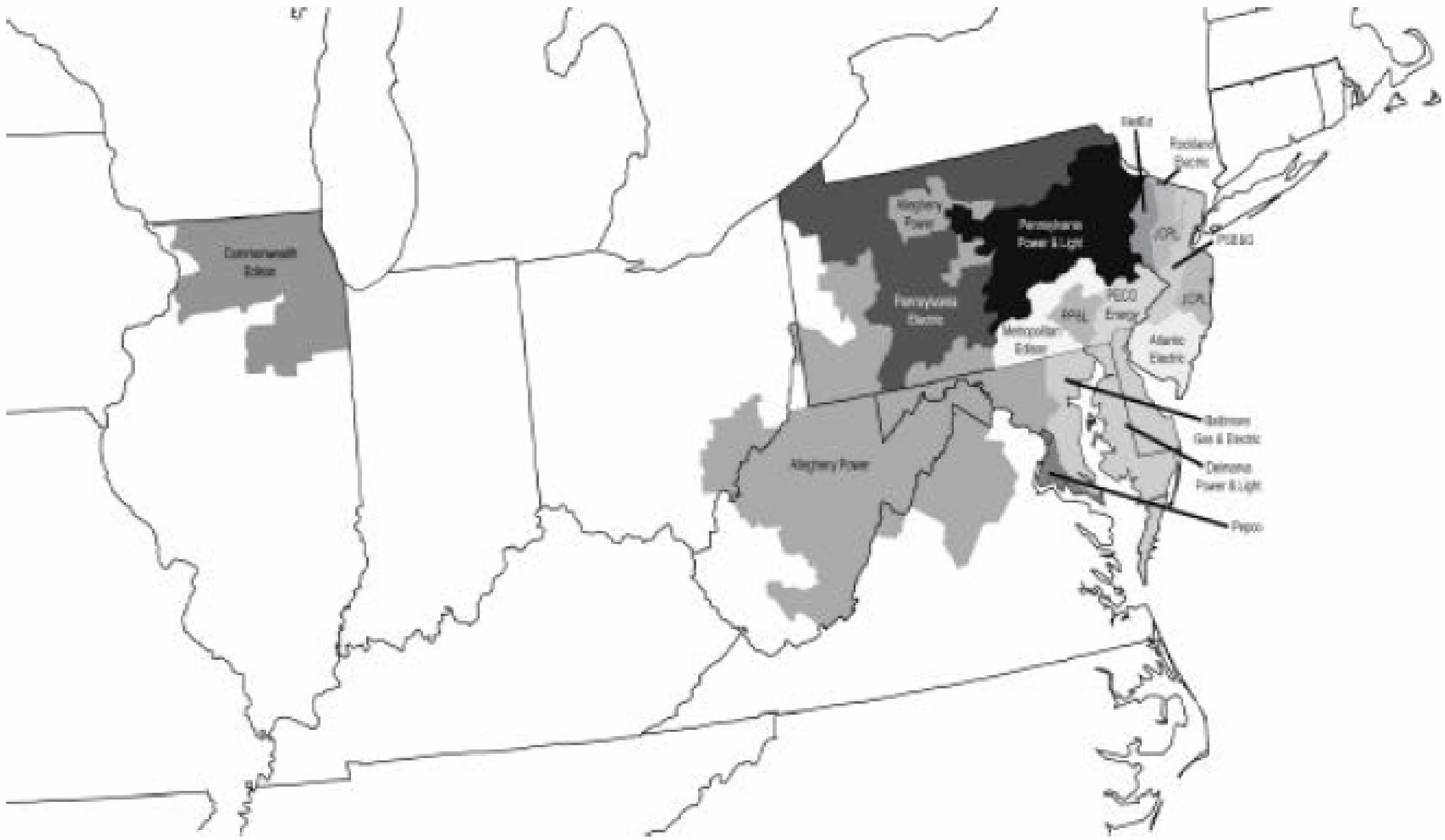
PJM RTO (2003)



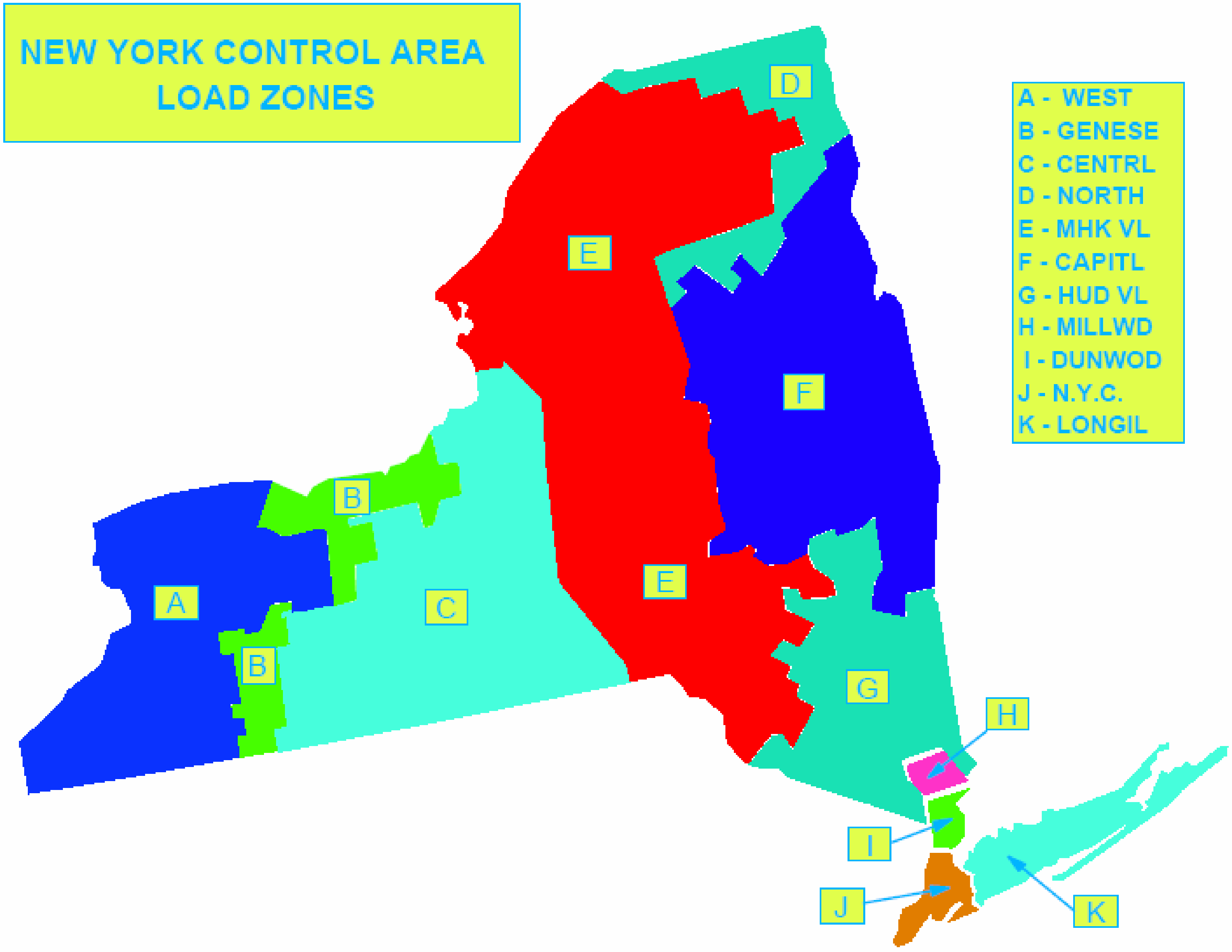
Source: PJM

PJM RTO 2004

PJM Transmission Zones



Source: PJM



Source: NY ISO

BASIC ATTRIBUTES OF NORTHEASTERN RTO/ISOs

- Independent System Operator
  - Non-profit entity that does not own transmission assets
  - Responsible for operating reliability of network
  - Control area operator
  - Manages Open Access Transmission Tariff and OASIS
  - Manages voluntary wholesale markets for power and ancillary services
  - Manages requests for transmission service, allocation of scarce transmission capacity and network expansions
  - Regional Transmission Expansion Planning process
  - Market monitoring and mitigation programs
  - Coordination with neighboring control areas, including imports/exports (cross-border trade)
- Regulated Incumbent Transmission Owners (TO)
  - Functional separation rules due to vertical integration
  - Opportunities for merchant projects

BASIC FEATURES OF WHOLESALE MARKET DESIGN

- Security constrained bid-based dispatch using state-estimator network model
  - Day-ahead hourly markets
  - Real-time market (adjustments, imbalances, 5-minutes)
  - Self-scheduling permitted subject to imbalance and congestions charges
- Resulting LMPs calculated at each bus
  - Marginal cost of congestion
  - Marginal cost of losses (not yet in PJM)
- Market-based provision of ancillary services integrated with day-ahead and real-time energy markets
- All transmission service customers must pay costs of congestion based on differences in LMPs between source and sink of power transactions
  - Day-ahead
  - Real-time

BASIC FEATURES OF WHOLESALE MARKET

- Financial Transmission Rights (FTRs) allocated (theoretically) consistent with network feasibility constraints
  - Rights to proportionate share of congestion rents
  - Initial allocation based on transmission ownership to serve “native load,” third-party contracts for firm transmission service or investment in new T capacity
  - FTRs are tradable and there are reconfiguration opportunities
  - Auctions (annual, monthly) and Auction Revenue Rights (PJM)
  - Obligation rights, option rights, peak, off-peak rights (PJM)
- Generating capacity (reserve) obligations imposed on LSE (e.g. 18% forward reserve margin)
  - Load reduction capabilities are eligible
  - Capacity resources must meet deliverability criteria (PJM)
  - Designated capacity resources must make energy available to the SO through bids

MARKET MONITORING AND MITIGATION

- $1000/MWh general bid cap
- Local market power mitigation rules
  - Bid caps
  - RMR contracts
  - Must-offer restrictions
  - Interaction with computation of market prices
- Must offer requirements
- Ex-post bid/price adjustments
- Monitoring of individual market participant behavior and market performance

TRANSMISSION PRICING (PJM)

- Firm Network Integration Service
  - Designed to replicate transmission service available "internally" to vertically integrated LSEs in PJM with their own T networks.
  - LSE's transmission service price equals average total cost of transmission network per MW of peak load based on cost of transmission facilities in load areas (license plate tariff --- $15-$25/KW-year) + network enhancement charges, if any
  - Cost-of-service rate of return regulation determines prices. No PBR for operating costs, availability, outage response (yet)
  - Transmission customers pay congestion charges and losses.
  - Receive FTRs/ARRs for designated sources and sinks
- Firm point-to-point service
  - Imports, exports, transit, internal transactions not otherwise covered by network integration service
  - Term: one day to one year (short-term). One year or more by agreement (long term).
  - Average total cost of transmission system in delivery area ($15 - $25/KW-year) or PJM border + enhancement charges
  - Receive FTR/ARR allocation
  - Responsible for congestion charges and allocation of losses

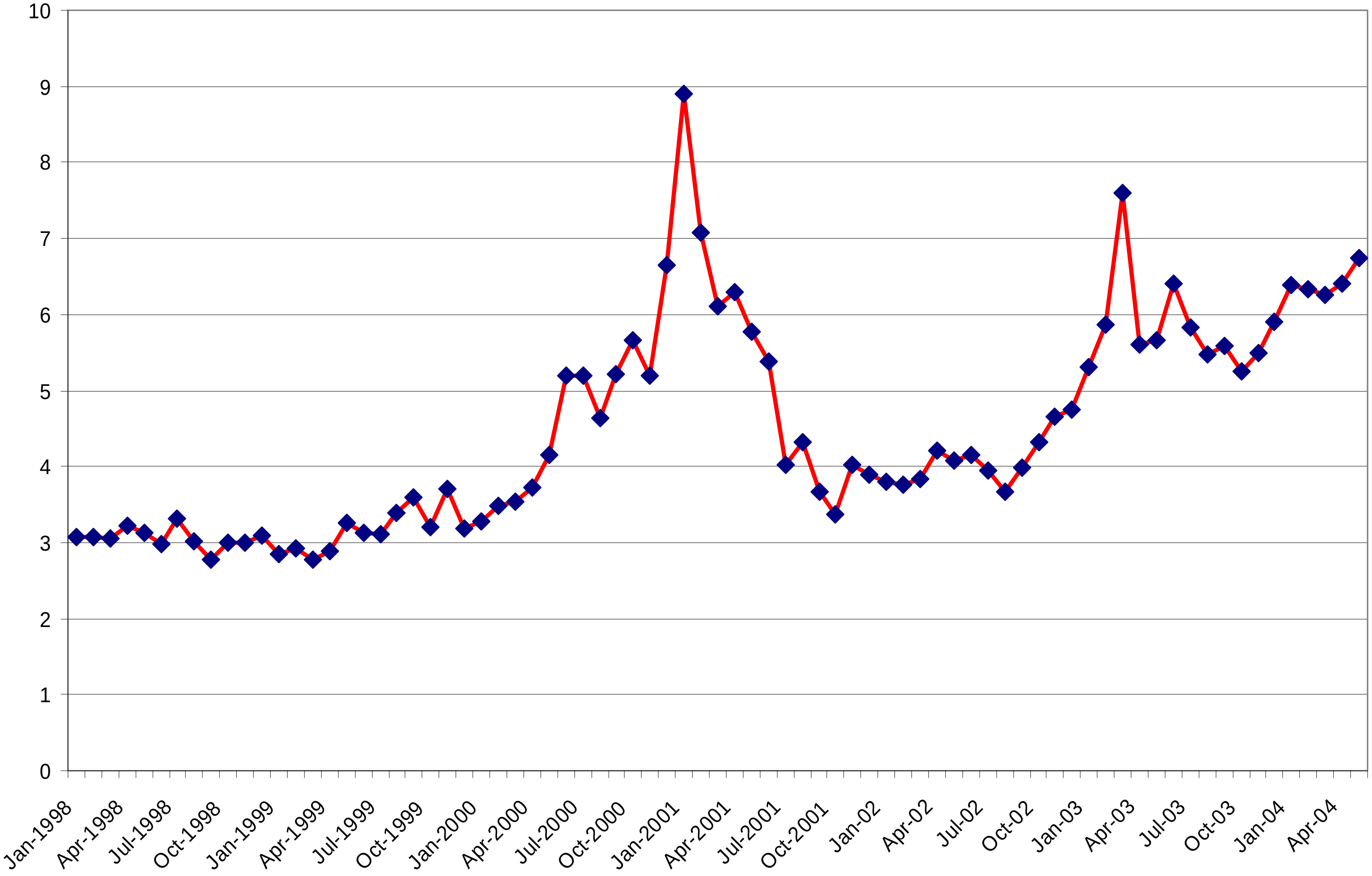
TRANSMISSION PRICING (PJM)

- Non-firm point-to-point service
  - Term: One hour to one-month
  - Curtailed first to relieve congestion with option to pay congestion charges and avoid curtailment
  - Same average total cost-based price per Kw-time as firm but no network enhancement charges (can be discounted)
  - Hourly on-peak transmission service fee averages about $5/Mwh on peak
  - Loss charges are added
  - No FTRs included

TRANSMISSION PRICING (PJM)

- Transmission charges paid by generators and merchant transmission projects
  - Direct interconnection costs
  - Incremental network upgrade costs to maintain MAAC reliability criteria (incremental FTRs allocated)
    - Sharing protocol for groups of new generators
  - Incremental network upgrade costs to meet MAAC deliverability criteria to be certified as a "capacity resource" (incremental FTRs allocated)
  - Congestion charges and losses only if the generator is also providing supporting transmission service for the transaction or by agreement with buyer (e.g. an export by a merchant generator)

AVERAGE CITY-GATE NATURAL GAS PRICES (1998 -2004)
$/MCF



Source: EIA

Table 2-23 PJM Average Hourly Locational Marginal Prices (in Dollars per MWh)

	Locational Marginal Prices (LMP)			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2003	$38.27	$30.79	$24.71	35.2%	46.0%	10.3%
2002	$28.30	$21.08	$22.40	-12.6%	-8.3%	-50.6%
2001	$32.38	$22.98	$45.30	15.1%	20.3%	76.3%
2000	$28.14	$19.11	$25.69	-0.6%	6.9%	-64.5%
1999	$28.32	$17.88	$72.41	30.4%	7.7%	130.2%
1998	$21.72	$16.60	$31.45			

Source: PJM State of Markets 2003

Table 2-26 PJM Load-Weighted, Fuel-Cost-Adjusted LMP (in Dollars per MWh)

	2003	2002	Percent Change
Average LMP	$28.60	$31.60	-9.5%
Median LMP	$24.40	$23.41	4.2%
Standard Deviation	$16.94	$26.74	-36.6%

Source: PJM State of Markets 2003

Table 2-1 Peak PJM Demand Days: 2001, 2002 and 2003

	22-Aug-03	14-Aug-02	9-Aug-01
Peak Demand (MW)	61,500	63,762	62,232
Maximum Daily LMP ($ per MWh)	$95.11	$445.30	$932.30
Average PJM LMP ($ per MWh)	$58.47	$88.00	$387.70
Average Peak PJM LMP ($ per MWh)	$65.89	$122.30	$559.40
Average Off Peak PJM LMP ($ per MWh)	$43.61	$19.20	$44.20

Source: PJM State of Markets 2003

Table 2-27 Comparison of Real-Time and Day-Ahead 2003 Market LMP (in Dollars per MWh)

	Day-Ahead	Real-Time	Difference	Difference as Percent Real-Time
Average LMP	$38.72	$38.27	-$0.45	-1.2%
Median LMP	$35.21	$30.79	-$4.43	-14.4%
Standard Deviation	$20.84	$24.71	$3.87	15.7%

Source: PJM State of Markets 2003

Table 2-33 2003 Demand-Side Response Program

PJM Programs	MW Registered
PJM Economic Load-Response Program	724
PJM Emergency Load-Response Program	659
PJM Active Load-Management Resources	1,207
PJM ALM Resources Included in Load-Response Program	(445)
Total PJM Programs	2,145

Source: PJM State of Markets 2003

Table 24 – Quarterly Statistics for Daily All-In Price of Wholesale Electricity ($/MWh)

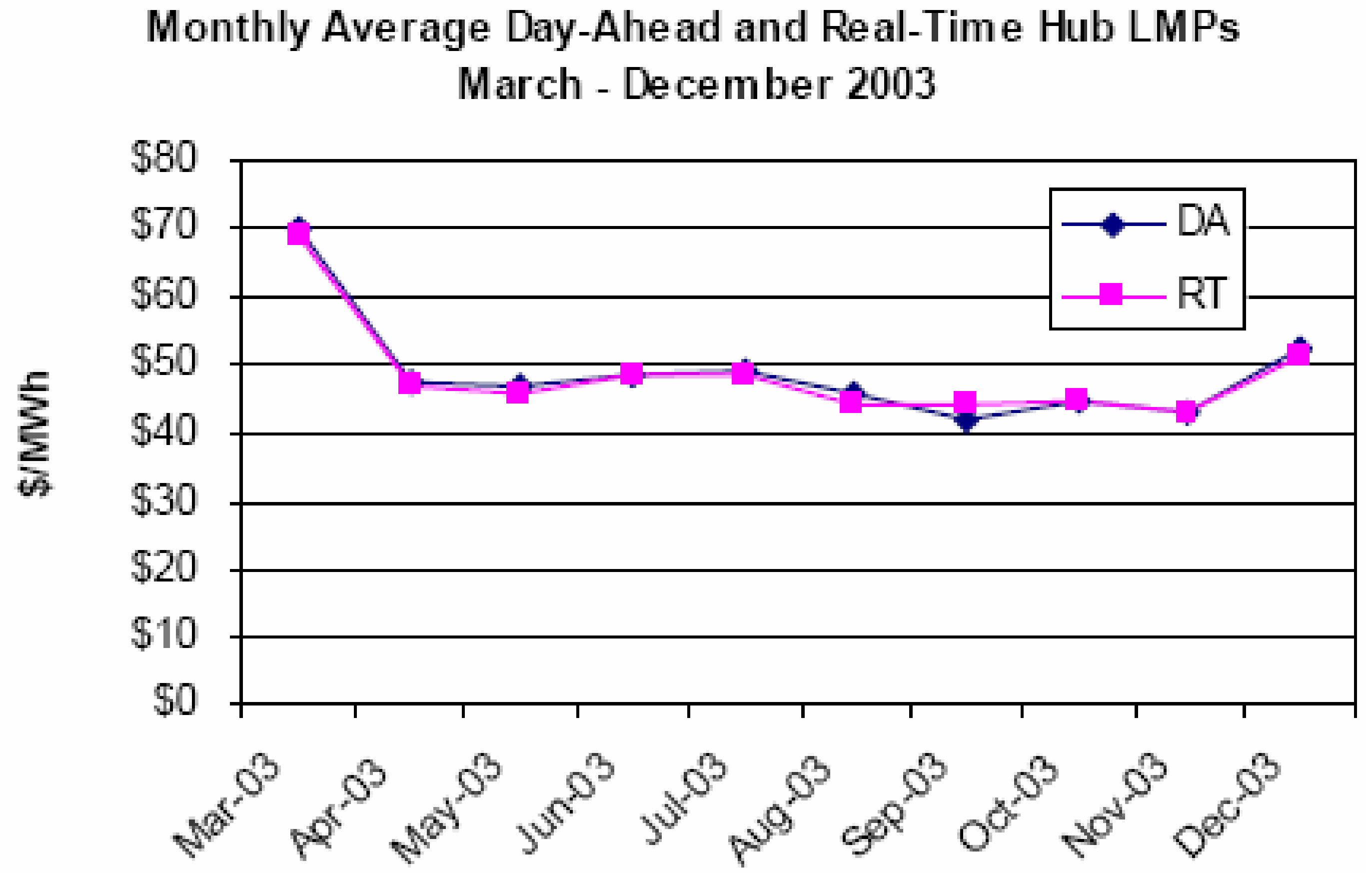
Year	Mean Daily Price	Median Daily Price	Max. Daily Price	Min. Daily Price	Std. Dev. Daily Price
1999 Q2	$39.40	$29.07	$232.37	$23.54	$42.09
2000 Q2	$44.31	$33.45	$1,219.56	$20.18	$107.72
2001 Q2	$42.31	$41.96	$91.41	$17.11	$11.59
2002 Q2	$32.43	$32.02	$52.22	$19.12	$5.80
2003 Q2	$52.65	$46.47	$150.24	$34.04	$18.45

Source: ISO New England

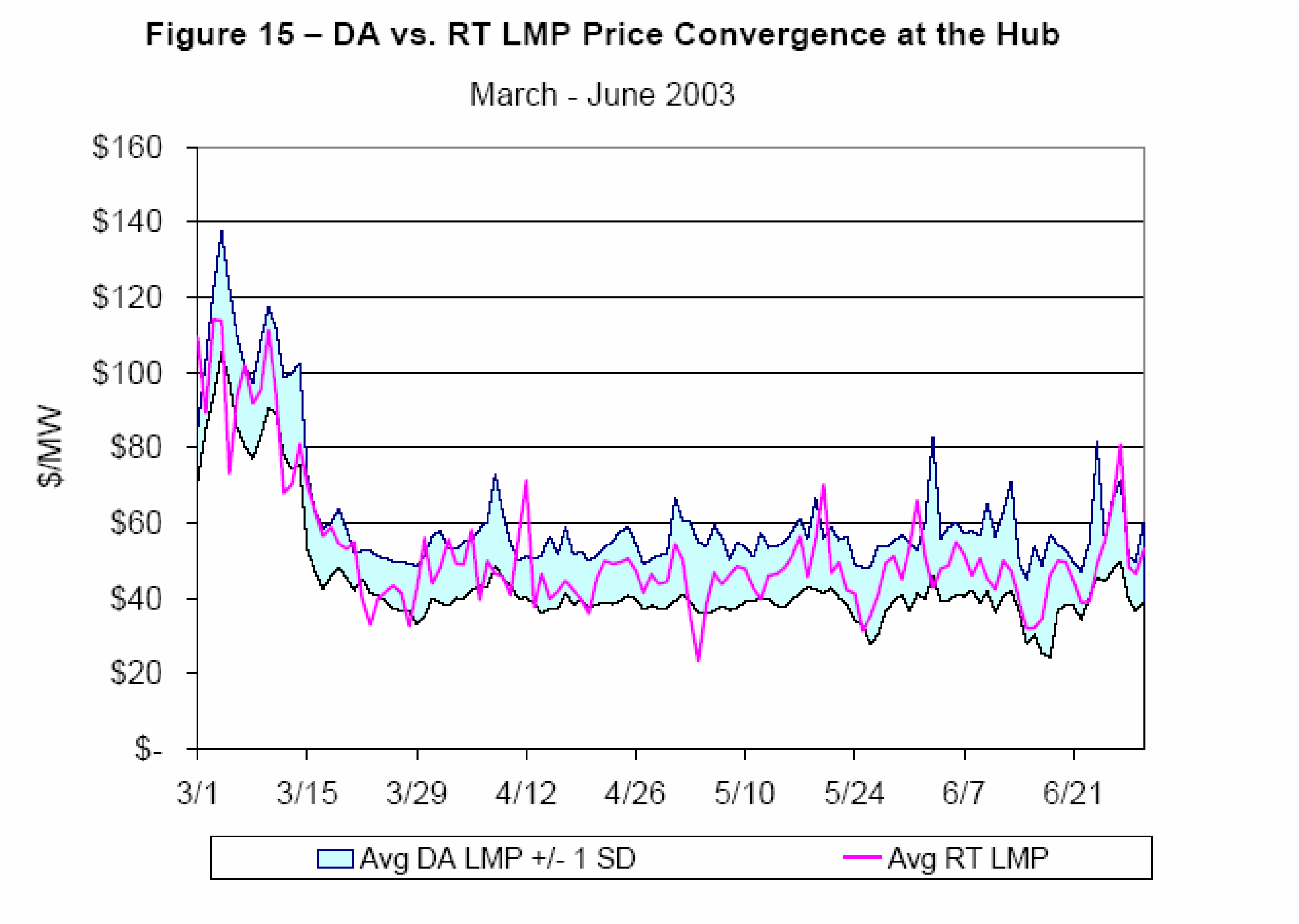
All In Price by Load Zone and System, Month Averages

	MAR2003	APR2003	MAY2003	JUN2003	JUL2003	AUG2003	SEP2003	OCT2003	NOV2003	DEC2003
Maine	$68.02	$42.50	$40.83	$42.44	$43.17	$40.05	$37.85	$41.51	$38.51	$46.33
New Hampshire	$68.27	$46.89	$43.86	$46.20	$47.06	$43.44	$40.64	$43.46	$40.86	$49.72
Vermont	$69.65	$47.93	$45.38	$47.79	$49.22	$45.66	$41.96	$44.92	$42.27	$50.70
Connecticut	$70.07	$48.80	$50.00	$50.75	$52.50	$51.85	$44.52	$49.05	$48.88	$54.58
Rhode Island	$67.37	$45.64	$45.60	$46.90	$46.47	$44.68	$40.13	$43.41	$41.46	$50.82
SEMASS	$67.09	$45.80	$45.76	$46.68	$46.72	$43.23	$39.88	$43.22	$41.45	$49.88
WCMASS	$69.28	$46.62	$46.01	$47.80	$48.17	$44.53	$41.74	$44.22	$42.20	$51.33
NEMA/Boston	$71.23	$48.07	$47.62	$49.30	$49.06	$46.65	$43.11	$46.31	$43.51	$51.48
System Overall	$71.44	$47.46	$46.64	$47.43	$48.66	$46.74	$42.31	$45.83	$44.00	$51.62

Source: ISO New England

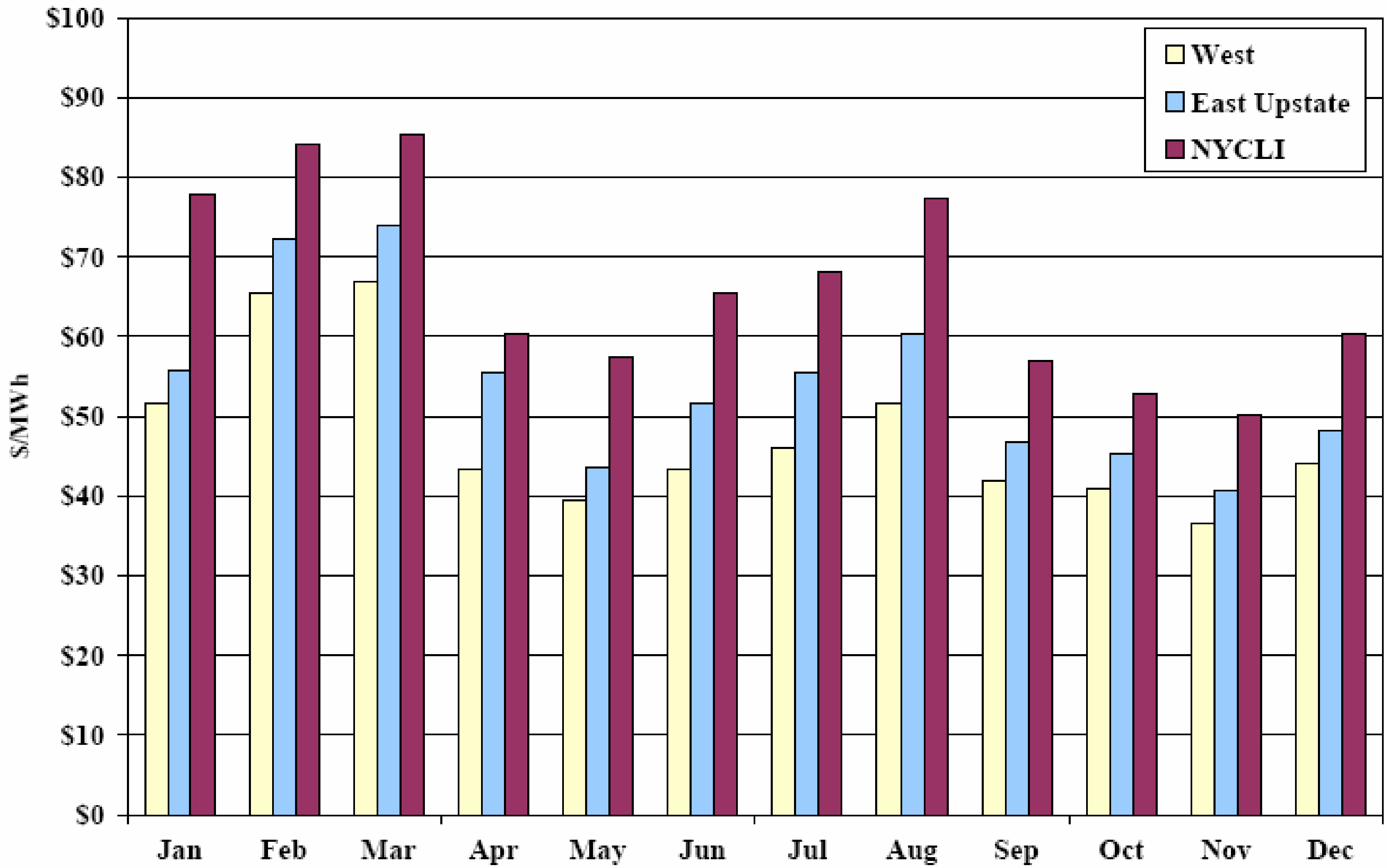


Source: ISO New England

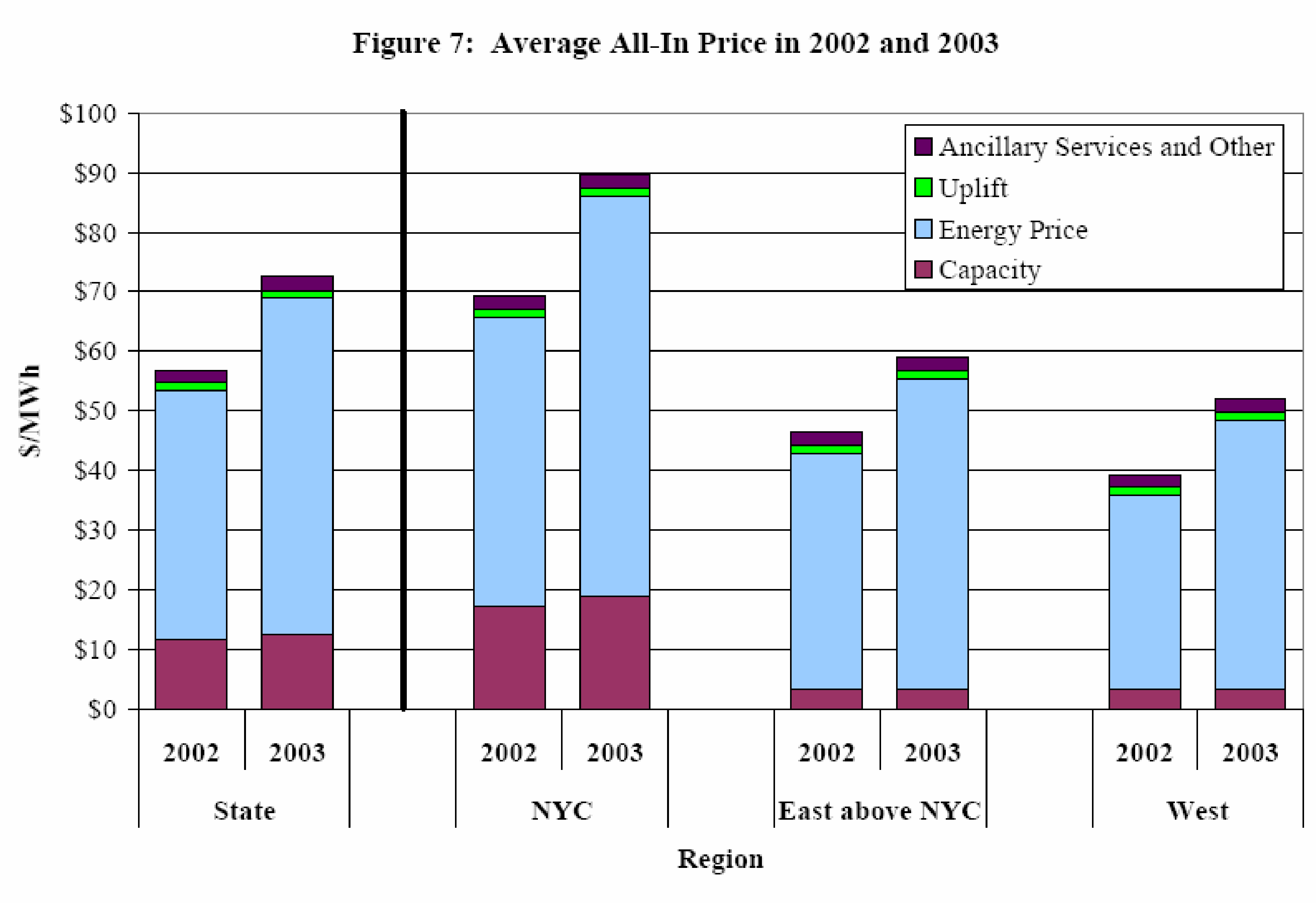


Source: ISO New England

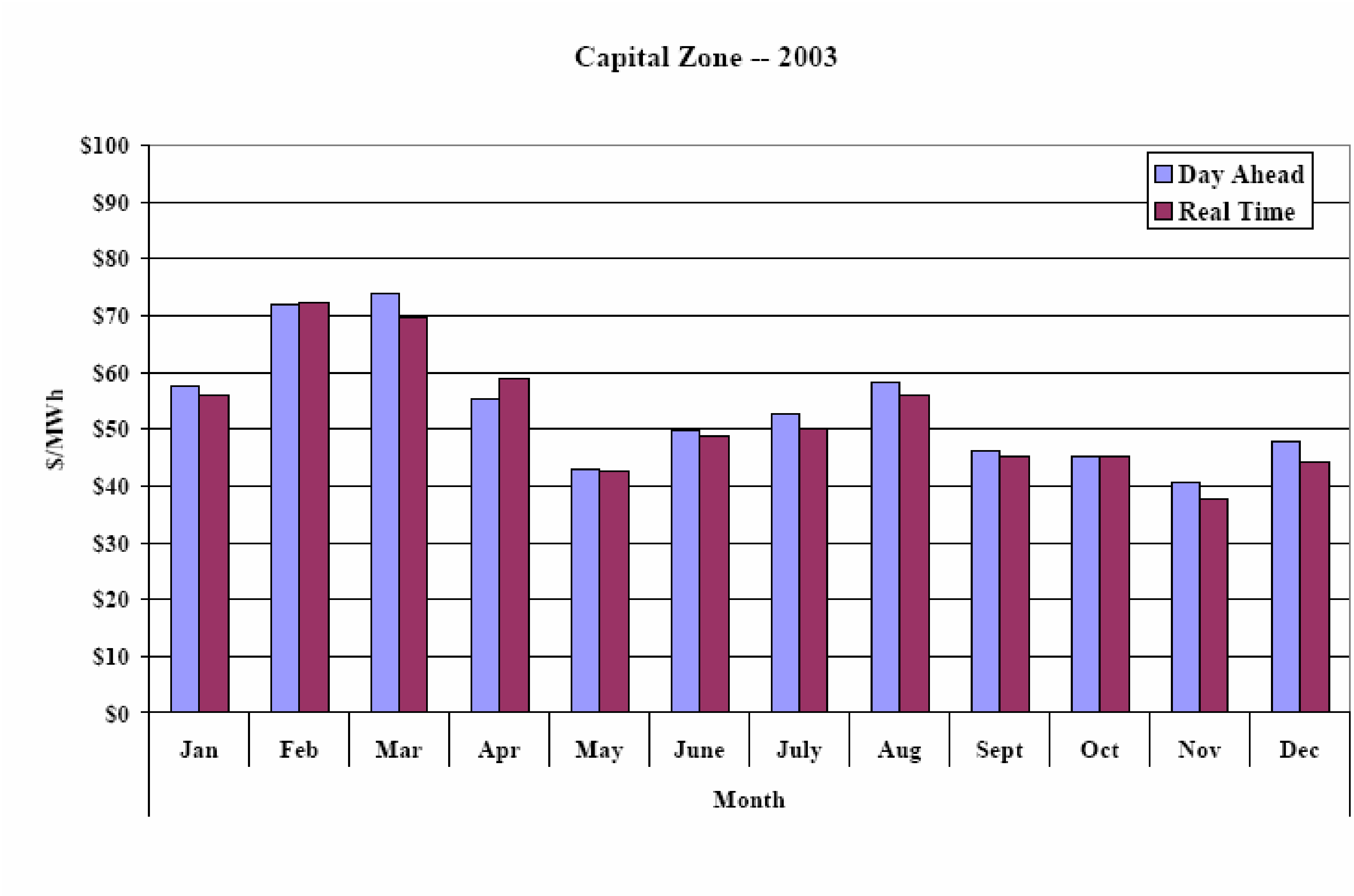
Figure 4: Day-Ahead Energy Prices in 2003



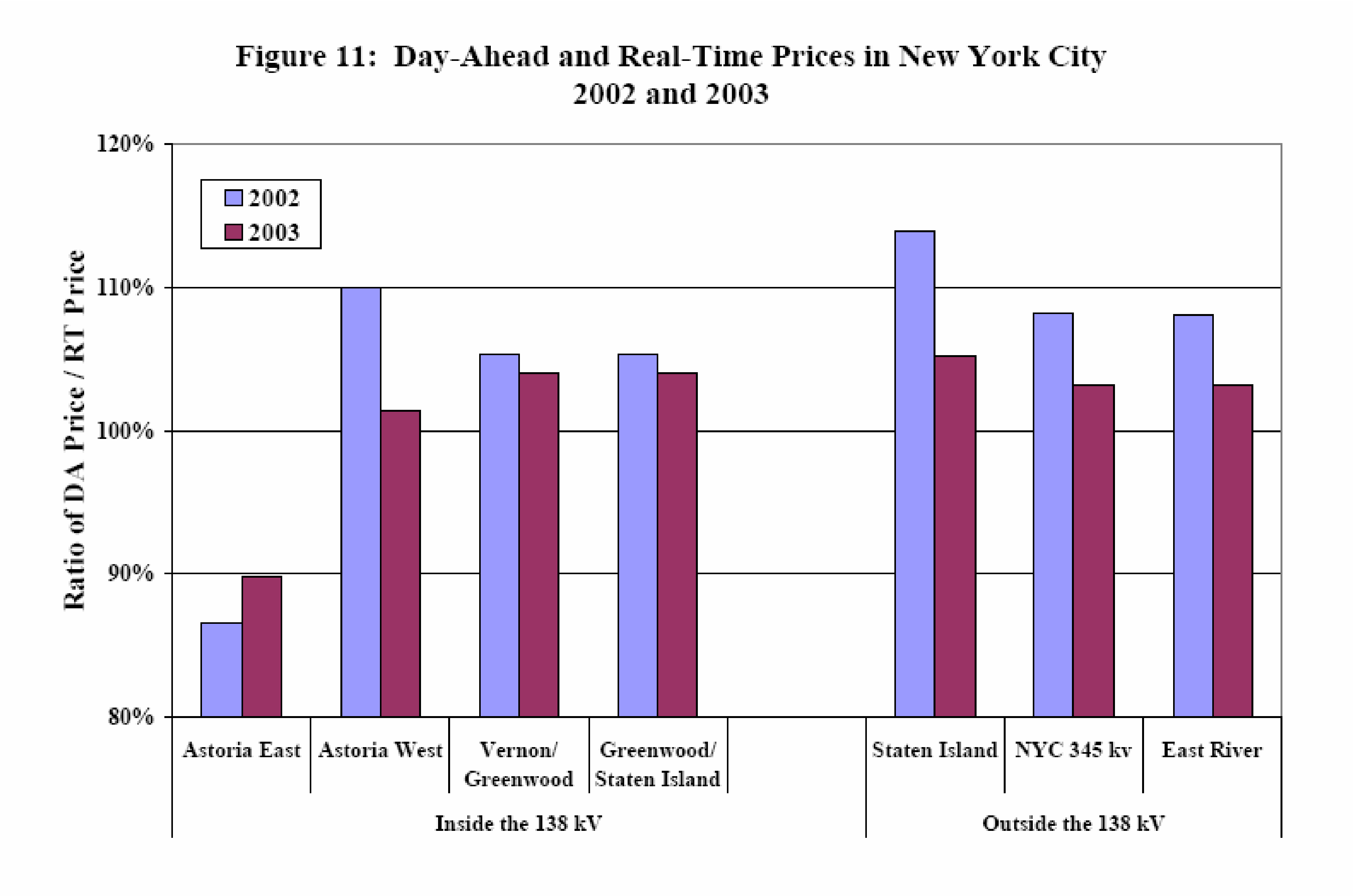
Source: New York ISO (2004)



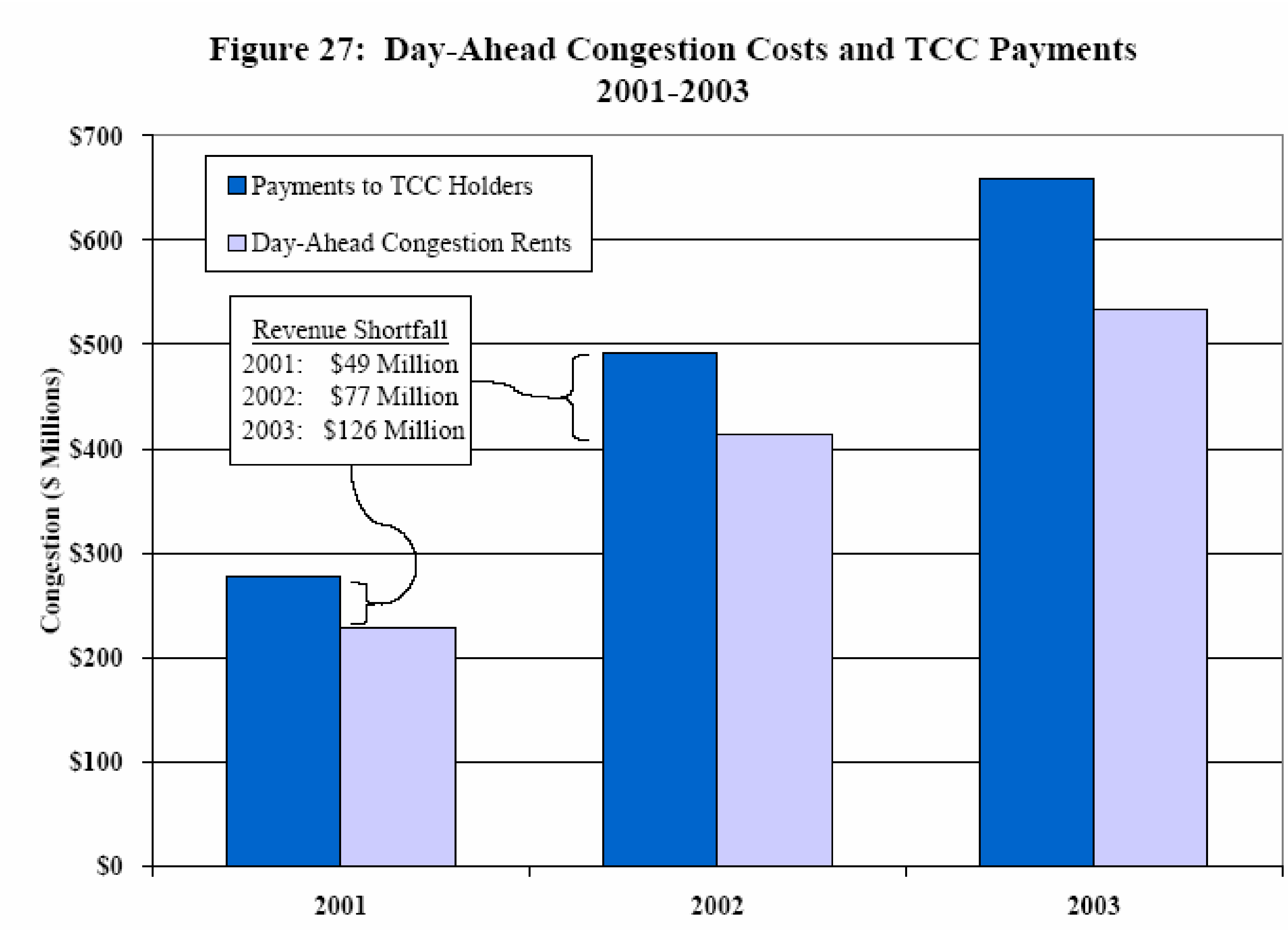
Source: New York ISO (2004)



Source: New York ISO



Source: New York ISO (2004)



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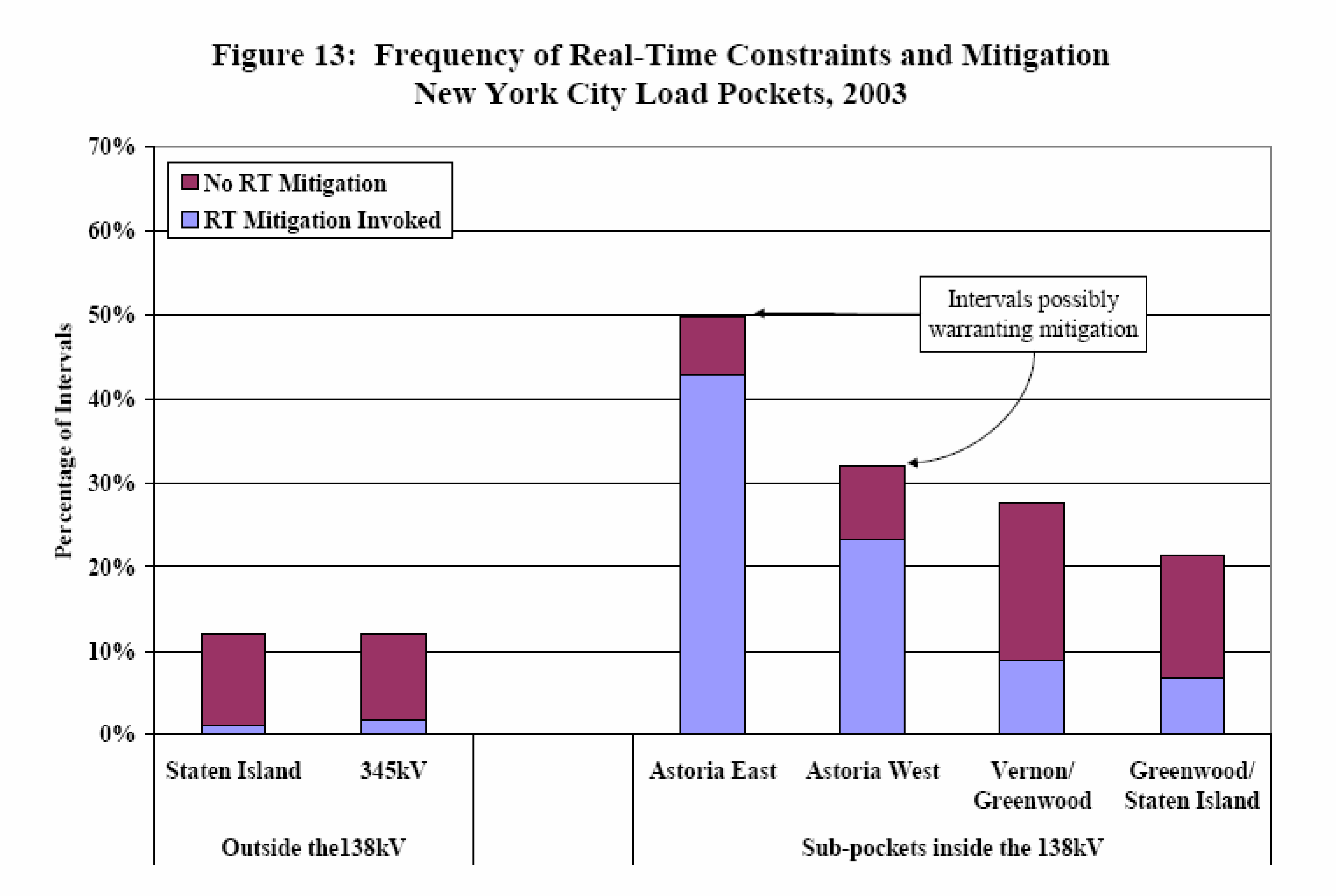

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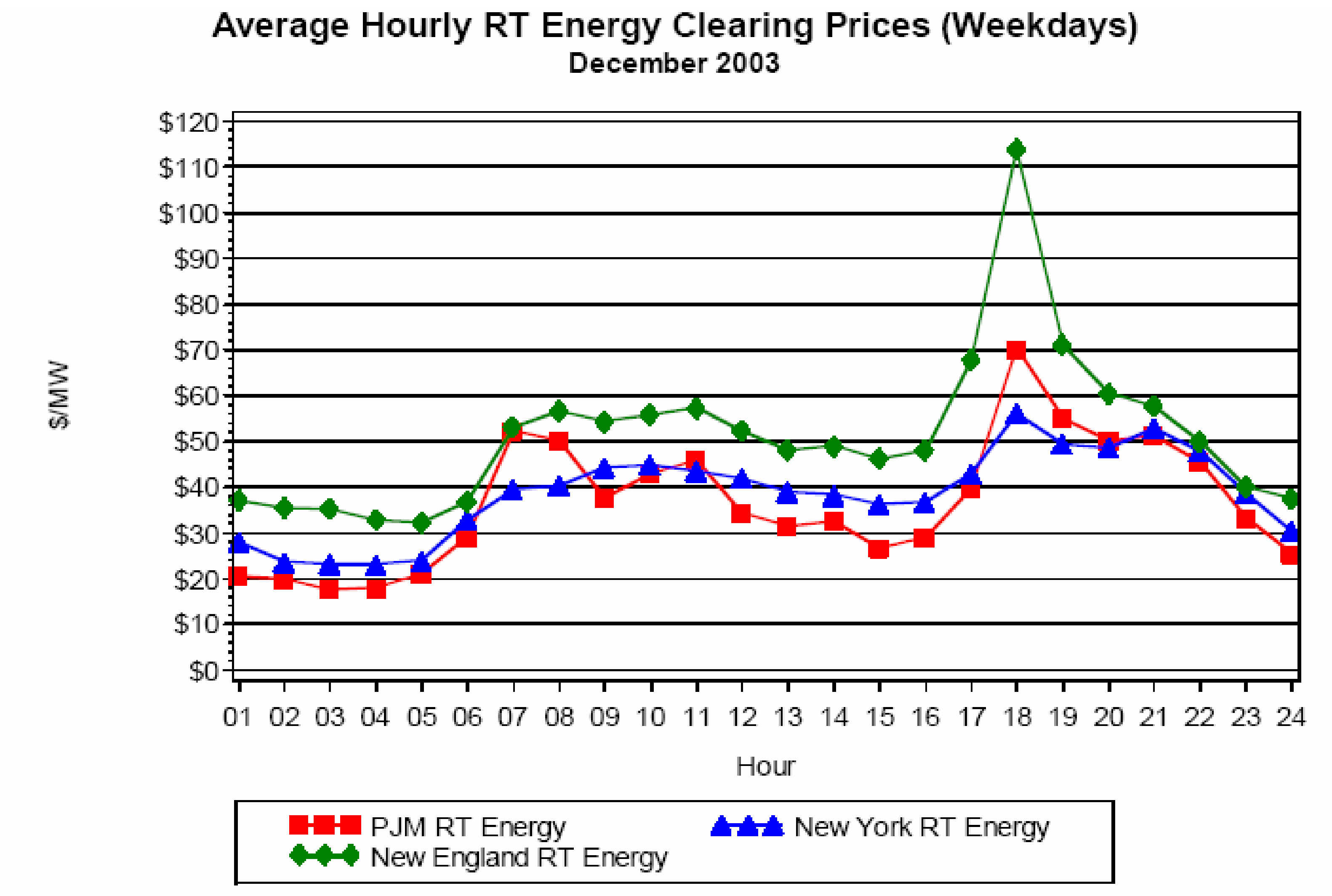
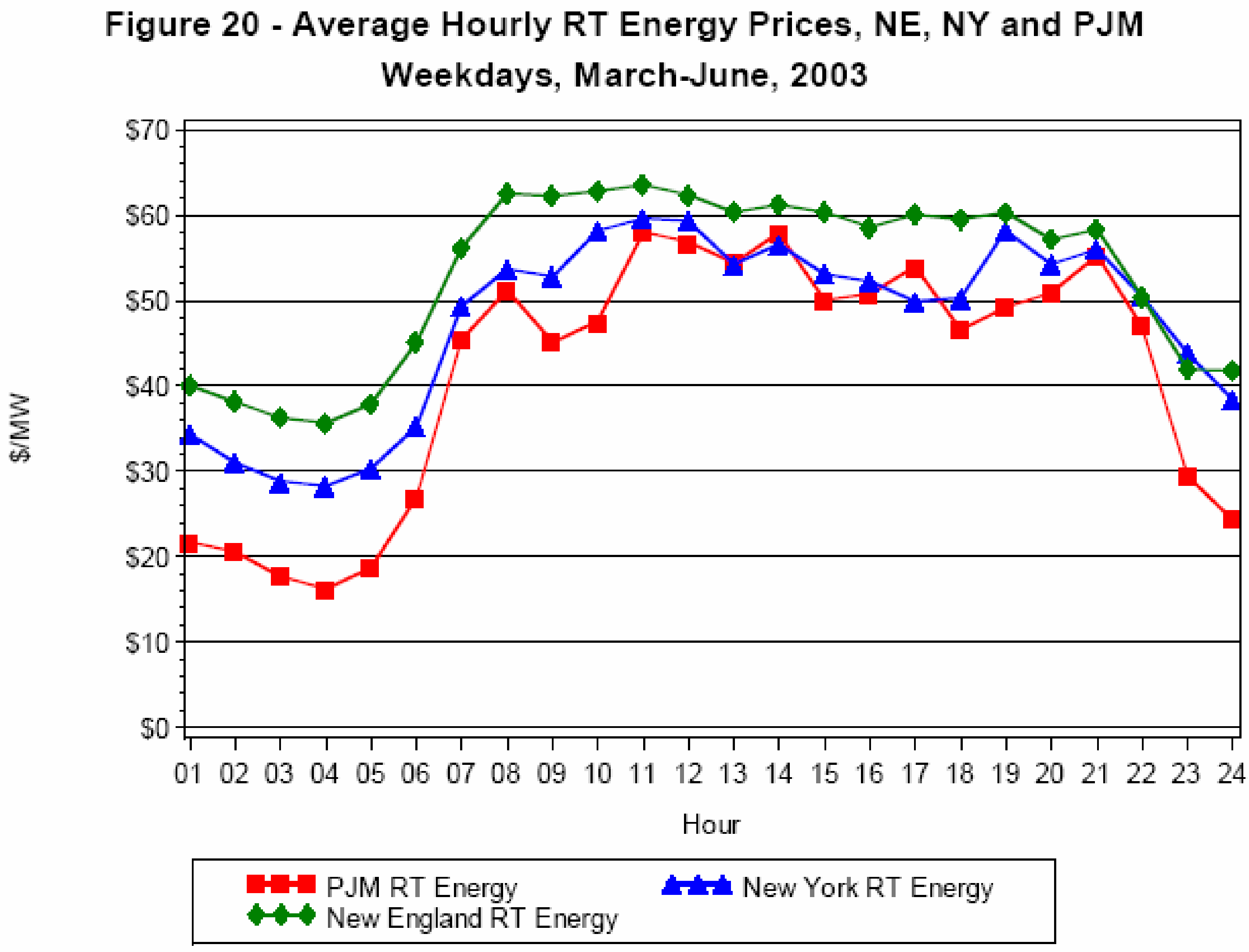


Source: ISO New England



Source: ISO New England

DAY-AHEAD PEAK PRICES (2004) $/MWH

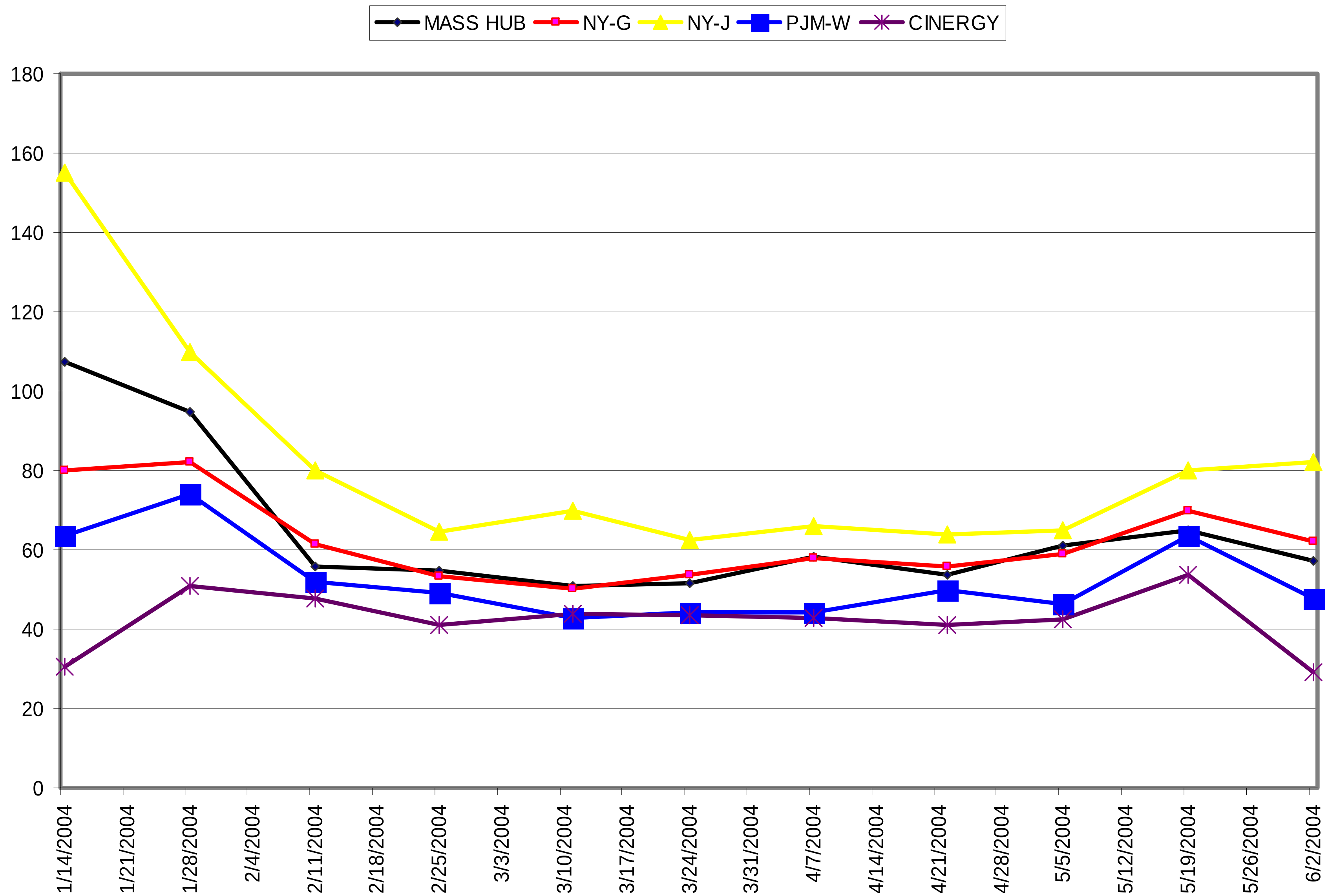
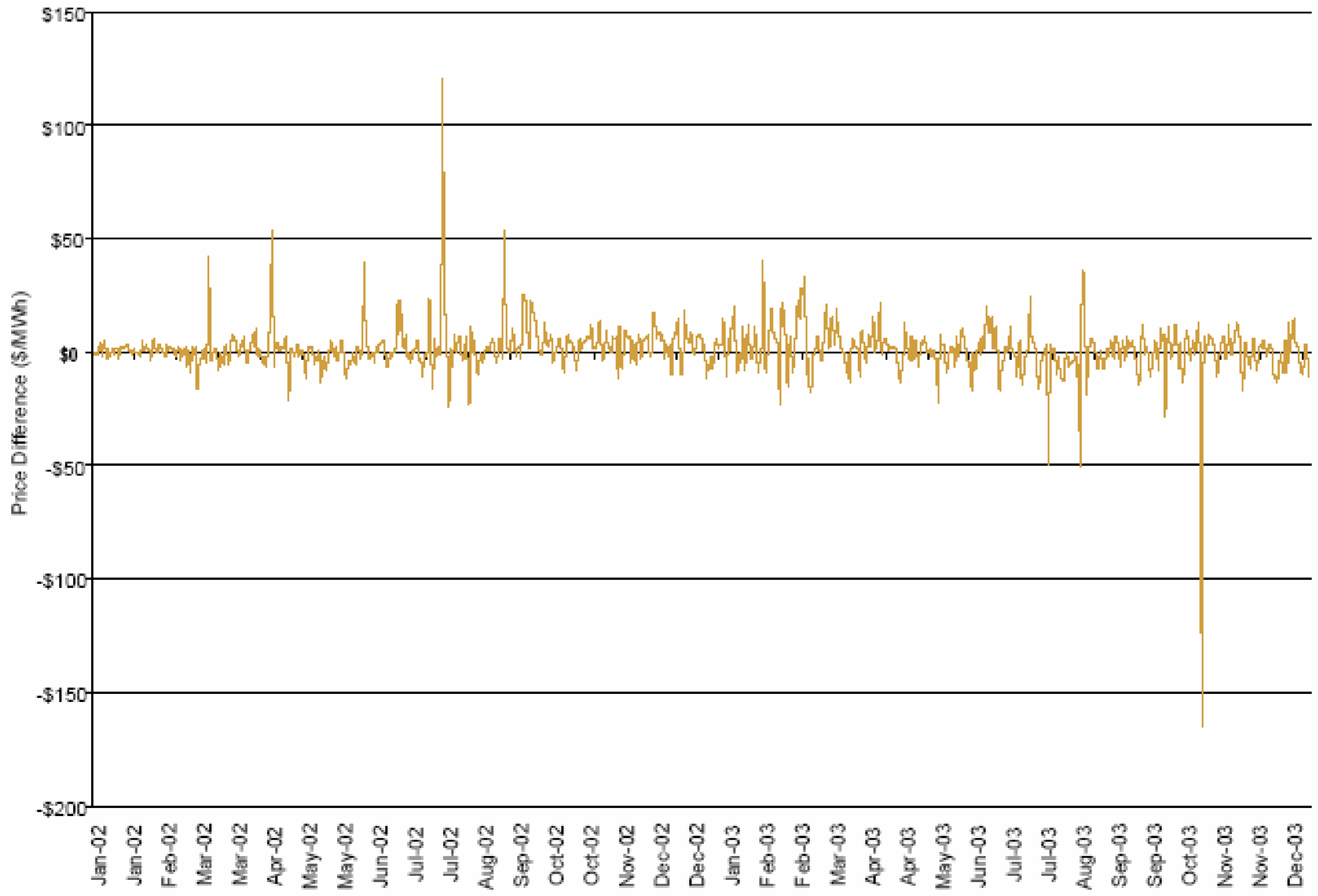


Figure 3-10 Daily Hourly Average Price Difference (NY Proxy - PJM/NYIS)



Source: PJM State of Markets Report 2003

FORWARD MARKETS
$/Mwh 6x16 Contract
(June 30, 2004)

Delivery Location	July 04	Aug 04	Q4-04	June 05	Cal 05	Cal 06
MA Hub	70.0	72.0	62.75	61.0	64.75	60.0
NY Zone A	61.25	63.0	-	-	55.75	-
NY Zone G	74.0	76.0	-	-	66.25	-
NY Zone J	99.0	100.0	-	-	83.25	-
PJM West	64.6	67.0	50.25	53.25	52.5	49.75
Cinergy	52.3	54.8	40.8	46.3	45.9	43.0

Source: Platt's *Megawatt Daily*, June 30, 2004

Table 2-17 New Entrant Combustion Turbine and Combined-Cycle Plant Theoretical Net Revenues

Economic Dispatch Generic CT and CC Net Revenue Streams ($ per Installed MW - Year)								
Gas-Fired								
Year	CT Energy	CC Energy	Capacity	Ancillary	CT Total	CC Total	CT Run Hours	CC Run Hours
2003	$15,380	$53,743	$5,936	$3,880	$25,196	$63,559	964	2,791
2002	$27,626	$57,148	$11,601	$3,915	$43,142	$72,664	1,383	3,206
2001	$44,481	$74,831	$36,700	$3,823	$85,004	$115,354	1,373	3,507
2000	$19,876	$45,236	$23,308	$4,594	$47,779	$73,138	926	2,201
1999	$73,480	$97,603	$20,469	$3,444	$97,393	$121,516	1,415	4,199

Average Net Revenues/MW-year (1999-2003)

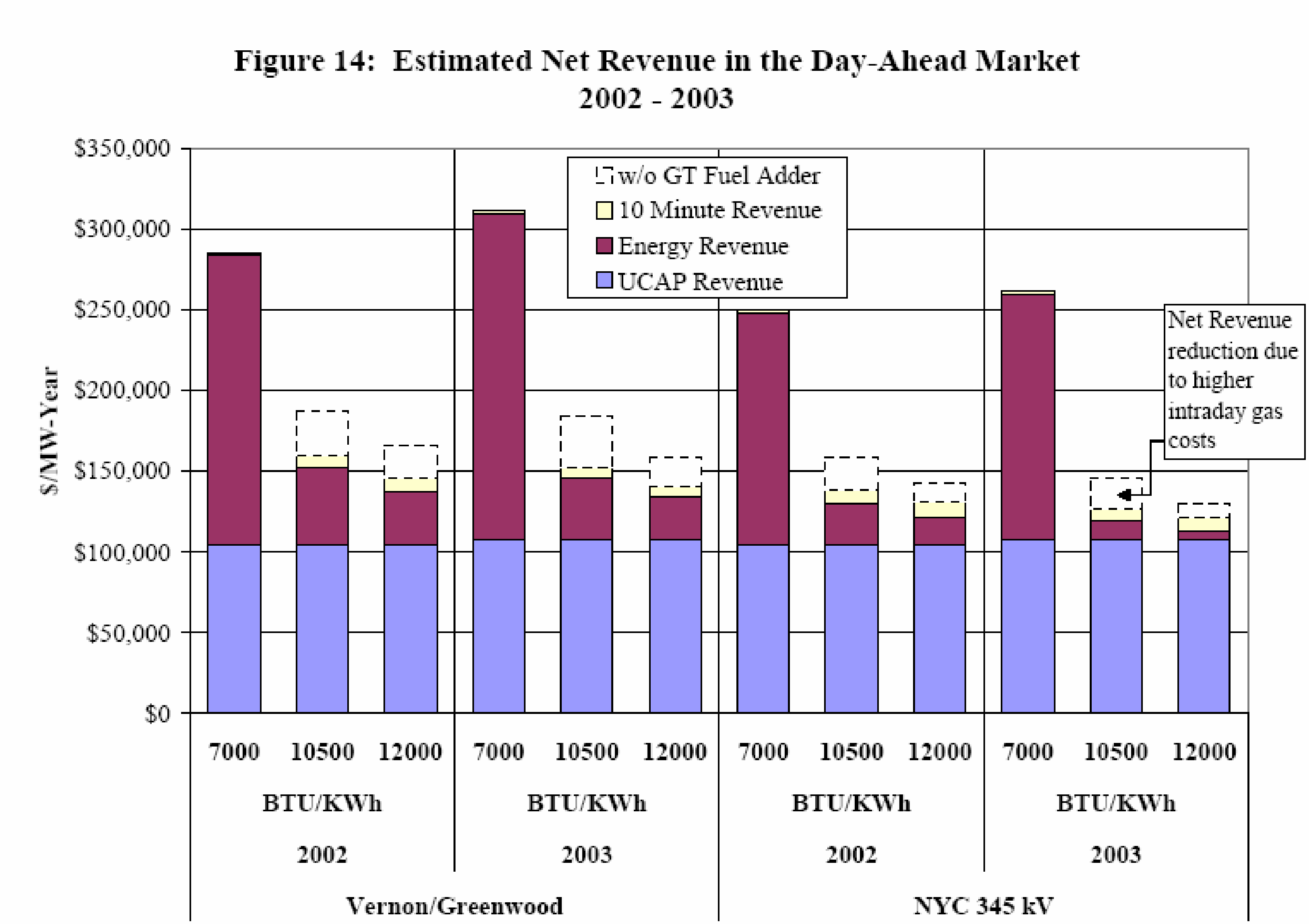
	Total	Energy Only
CT:	$60,000	$36,000
CC:	$90,000	$60,640

Source: PJM State of Markets 2003

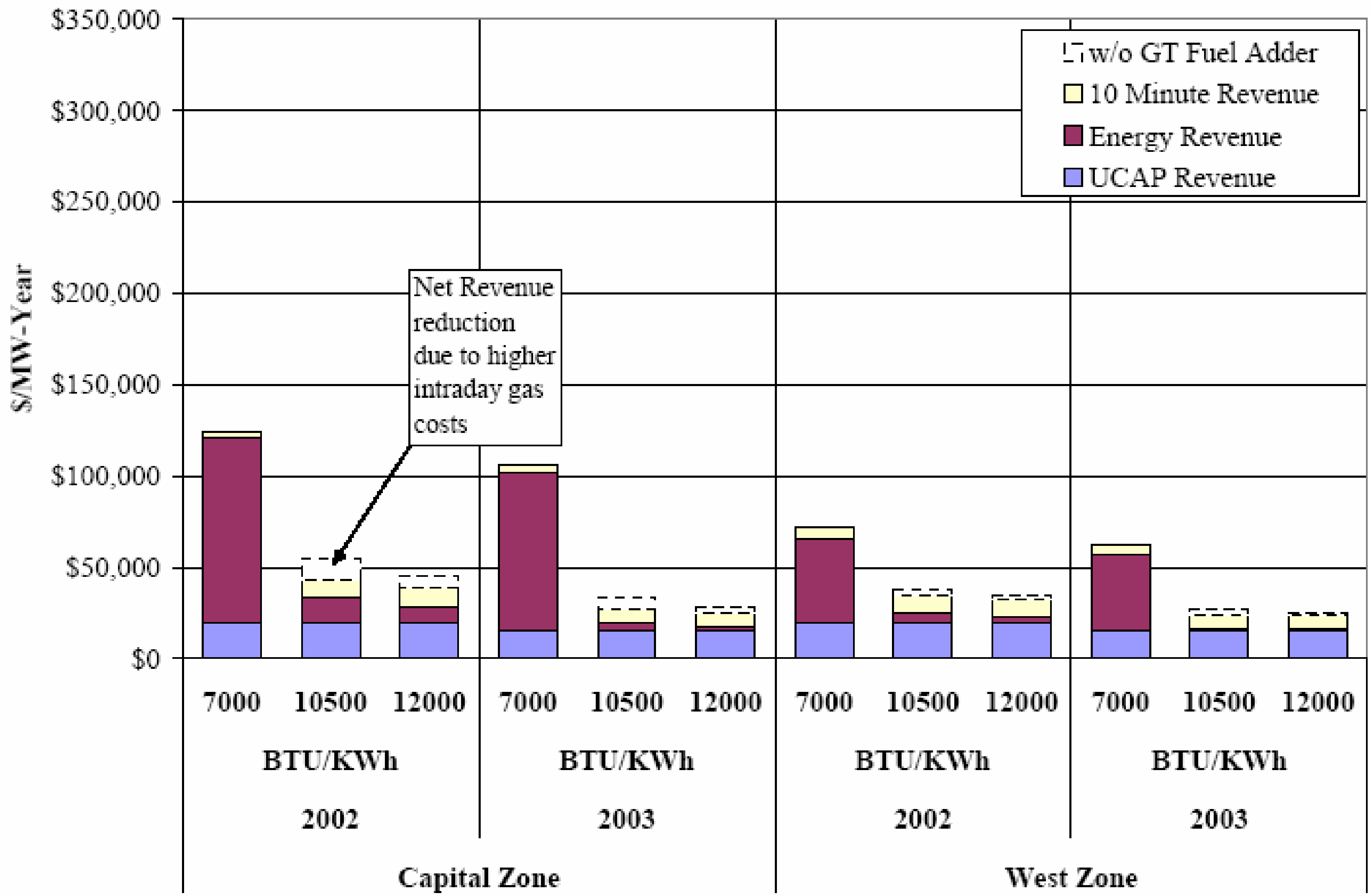
SCARCITY RENTS PRODUCED DURING OP-4 CONDITIONS ($1000 Price Cap) ($/Mw-Year)

YEAR	ENERGY MC=50	ENERGY MC=100	OPERATING RESERVES	OP-4 HOURS/ (Price Cap Hit)
2002	$ 5,070	$ 4,153	$ 4,723	21 (3)
2001	$15,818	$14,147	$11,411	41 (15)
2000	$ 6,528	$ 4,241	$ 4,894	25 (5)
1999	$18,874	$14,741	$19,839	98 (1)
Mean	$ 11,573	$ 9,574	$10,217	46 (6)

Peaker Fixed-Cost Target: $60,000 - $70,000/Mw-year



Source: New York ISO (2004)



Source: New York ISO (2004)

PJM CONGESTION EVENT HOURS

YEAR	TOTAL	500kv	345kv	230kv
1998	1,244	203	71	588
1999	2,134	189	148	818
2000	6,941	562	14	869
2001	8,435	759	38	744
2002	11,662	1,888	1,084	1,474
2003	9,711	1,985	705	3,016

Source: *PJM State of the Market Report 2002 and 2003*

PJM CONGESTION COSTS (RENTS)
($ millions)

1999	53
2000	132
2001	271
2002	430
2003	499

Source: PJM *State of the Market Report 2002 and 2003*

CONGESTION COSTS IN NEW YORK

2001	$310 million
2002	$525 million
2003	$688 million

TRANSMISSION INVESTMENT
PJM

- Heavy Influenced by legacy reliability rules and their implementation in the old regime
- Various Categories of investment
  - Direct Interconnection of generators or merchant transmission
  - Interconnection Network Upgrades to restore reliability parameters
  - Deliverability Network Upgrades
  - Other system reliability network upgrades
  - “Economic” upgrades
  - Merchant transmission
- Mediated through regional transmission planning process

TRANSMISSION INVESTMENT PJM

- MAAC has a complex hierarchy of reliability rules that are applied at the system level and to specific geographic areas (transmission zones)
- Engineering models are used to evaluate the system under various assumptions that bear no relationship to economic dispatch or congestion management
  - e.g. incumbent generators assumed to run to meet peak load and then generator being studied is assumed to run at peak capacity
- Distinctions between “reliability” investments and “economic” investments are quite arbitrary (e.g. generator deliverability)
- A significant fraction of “reliability” investments are really “economic” investments as they are modeled by economists
- New York and New England apply different reliability and economic considerations for transmission investment

PJM (MAAC) RELIABILITY RULES

- Normal system operating conditions
- N-1
- N-2
- Multiple Facility Contingency
- Generator deliverability
- Deliverability to load

TRANSMISSION INVESTMENT PJM

- TO in affected area designs, owns and operates transmission facilities approved in RTEP except for merchant transmission facilities which TO <u>may</u> also own
- Generators pay regulated cost of service prices for:
  - Direct interconnection facilities
  - Interconnection Network upgrades (incremental FTRs)
  - Deliverability network upgrades (incremental FTRs)
- LSEs shares costs of other reliability mandated network upgrades
- Merchants design, own, operate and pay for new merchant facilities and get FTRs for AC enhancements
- Costs of "economic" planned transmission facilities are shared by LSEs with customers who benefit from upgrades (recent addition still in process)

TRANSMISSION INVESTMENT PLANS PJM RTEP (11/03)

- Direct interconnection: $275 million
- Interconnection reliability and deliverability network upgrades: $214 million
- Other network reliability upgrades: $197 million
- Economic upgrades: (in process)
- Merchant
  - None completed to date and several proposals withdrawn
  - Most active projects are HVDC interconnects with New York or Long Island (supported by long term contract with LIPA)
  - Three transformer projects (one inside the fence of a refinery and two by incumbent TO) in development

TRANSMISSION INVESTMENT PLANS
ISO NEW ENGLAND (11/03)

- Interconnection + Reliability + Economic Benefit: $1.5 – $3.0 billion
- Mostly “reliability”
- All regulated projects

NORTHEASTERN MARKET ISSUES

- Seams Issues
  - Better integrate energy and ancillary services markets
  - Framework for expanding interconnections between control areas (merchant is now the only option)
- Local market power problems and solutions
- Incentives for investment in new generating capacity
- Implementation of “resource adequacy” obligations in the presence of retail competition
- Transmission investment framework
- Reliability and markets relationships
- Incentive regulation (PBR) to control transmission operating costs and improve reliability of transmission facilities
- Expand demand-side participation in the wholesale market
  - priority curtailment contracts
  - real time pricing