Market Price Forecasting in Competitive Electricity Markets

February 7, 2001

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Presentation Outline

Electricity Market Products

Market Evolution & Regulatory Climate

Locational Price Forecasting

- Locational Energy Market Clearing prices
- Locational Installed Capacity Market Clearing prices
- Transmission Rights
- Market drivers, sensitivities
- Market Power and Strategic Bidding

Appendix (TCA Methodology Details)

Electricity Market Products

- Energy
  - Can be purchased either from a trader, generator or from the spot market
- Installed Capacity (in New York and PJM)
  - Can be purchased in auctions
- Transmission Rights
  - Depends on *where* energy is purchased (upstream, downstream)
  - Can be purchased in auctions, or through bilateral trading
- Ancillary Services
  - Reserves
- Regulated Products
  - Transmission access charge
  - Real power losses (might be changing to market-based)
  - Reactive power
  - Scheduling and dispatch
  - Balancing energy

Market Evolution and Regulatory Climate

All the Northeast ISOs, particularly NEPOOL, are very much in the process of development and pose considerable risk to market participants. In the three markets, the rules are still evolving.

- NYPP, NEPOOL and Ontario are evaluating a day-ahead regional market to address the failure of market rules for commerce at the 'seams'.
- In NYPP, the reserve markets are being debated (locational or not).
- In PJM, separate markets for ancillary services are being considered.
- In NEPOOL:
  - The ICAP market has been eliminated but not the requirement.
  - The definition and allocation of FCRs are currently being debated.
  - The details of multi-settlement and congestion management are not finalized.

Market Evolution and Regulatory Climate

Northeast markets have significant differences, but are evolving toward integration.

	NEPOOL	NYPP	PJM
Settlement	• One real-time market, but plan a two-settlement system by late 2001	• A day-ahead and a real-time energy market	• Real-time market, with day-ahead market.
Reserves	• Separate markets for oper. reserves (including spinning and non-spinning reserve)	• (same as New England), non-spinning mkt was suspended and capped	• Currently no explicit reserves markets, except just implemented regulations market
Congestion Management	• Congestion costs are currently socialized; nodal congestion management model with FCRs planned for late 2001.	• Congestion management uses zonal-nodal model with TCCs; expected to move to full-nodal !!	• Congestion management uses nodal-based model and FTRs
Capacity Markets	• Eliminated installed capacity market but NOT the requirement.	• Locational installed capacity markets	• Single capacity market with Capacity Interchange Rights

Locational Energy Price Forecasting

Northeast markets have all adopted (or will adopt) locational pricing and centralized pools for their market structures.

- Loads and Generators bid into centralized pool (RTO operates all markets).
- In real time the system operator dispatches units so as to minimize cost (including transmission) given bids.
- "After the fact" (ex-post) LMP prices calculated at each bus.
- Distinct Clearing times / markets (day-ahead, hour-ahead) .
- Transmission property rights strictly financial (FTRs)– can have negative value.
- FTRs defined for every combination of nodes.
- Hubs defined to ease forward trading based on LMP averaging.

Locational Energy Price Forecasting – Perfect Competition

TCA's price forecasting model simulates the Northeast markets very closely to how they are actually operated, under assumptions of both perfect and imperfect competition.

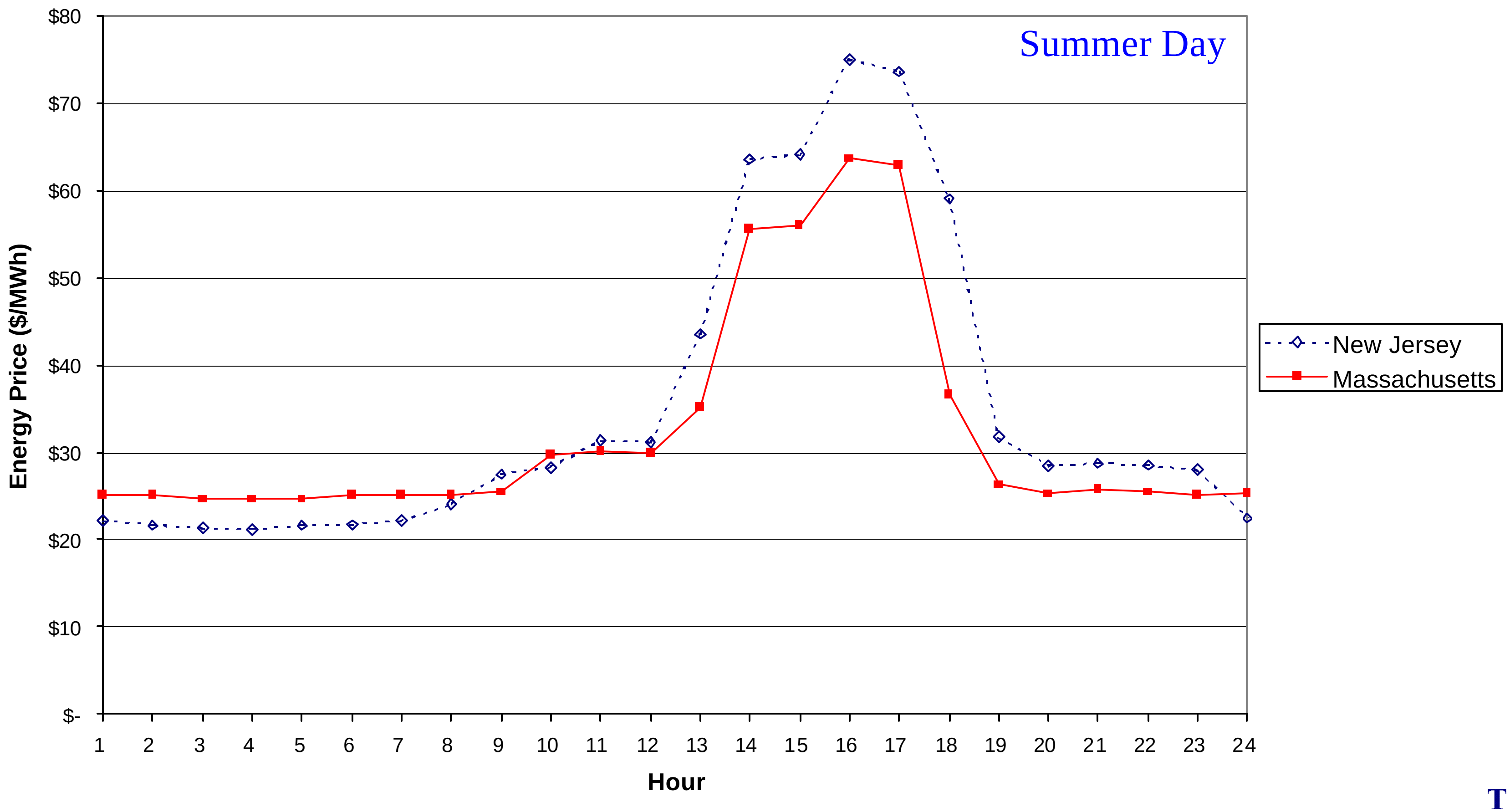
- TCA uses General Electric's Multi-Area Production Simulation Software (MAPS) to forecast locational energy prices.
- MAPS is a chronological, security-constrained dispatch model, that simulates very closely the operation of the PJM and New York markets and proposed operation of the NEPOOL market.
- MAPS assumes that generators bid their marginal cost, which is behavior expected in a perfectly competitive market
  - TCA performs a separate analysis to quantify the impact of market power.

Marginal Cost Bidding

- **Assumes perfectly competitive generation markets where generators bid their short run marginal costs**
  - **Fuel costs**
  - **Variable Operation and Maintenance costs**
  - **Tradable permits cost (NO_x, SO_x)**
- **Three part or single part bids**
  - **Three part bids include startup, min. generation and incremental block (PJM, NYPP).**
  - **Single part bids mean that generators have to internalize the startup costs and min. generation into the energy bid (NEPOOL).**

Illustrative Daily Variation in Price Forecast

The daily price profile tracks the regional load profile, and can be even more location-specific under conditions of congestion.



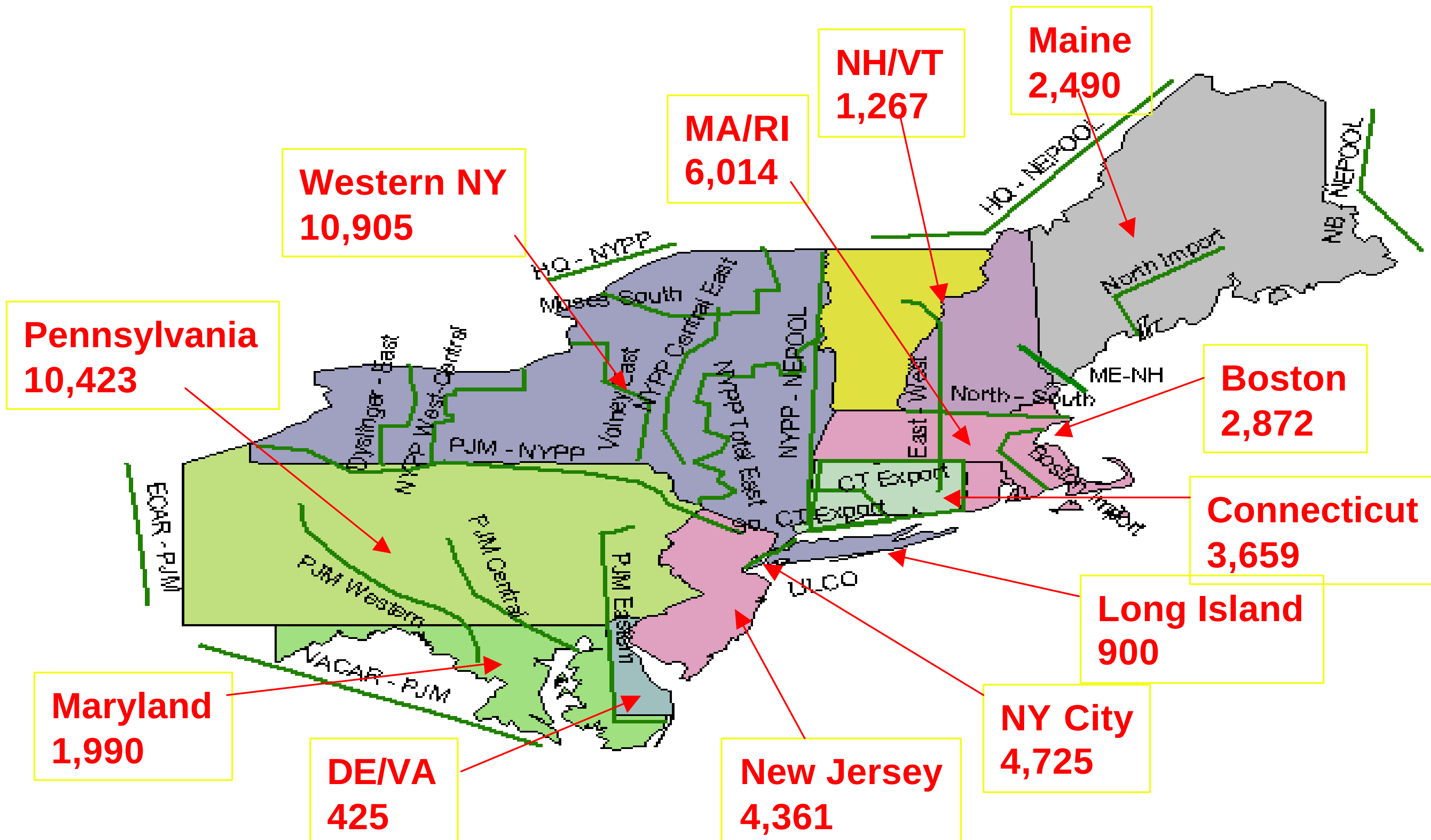
Market Drivers

We use scenario analysis to quantify the impact of major variables and forecast market clearing prices under different market conditions

- The key market uncertainties affecting market prices are:
  - Fuel prices (residual oil, natural gas)
  - Competitive new entry (combined cycle, gas-fired units)
    - Location of new units also has major implications for transmission congestion and locational prices
  - Load Growth
  - Environmental regulations (NOx and SOx emissions trading)
  - Scheduled and random outages
  - External imports (Hydro Quebec)

New Entry

Announced New Entry (MW) 2000-2005



T C A

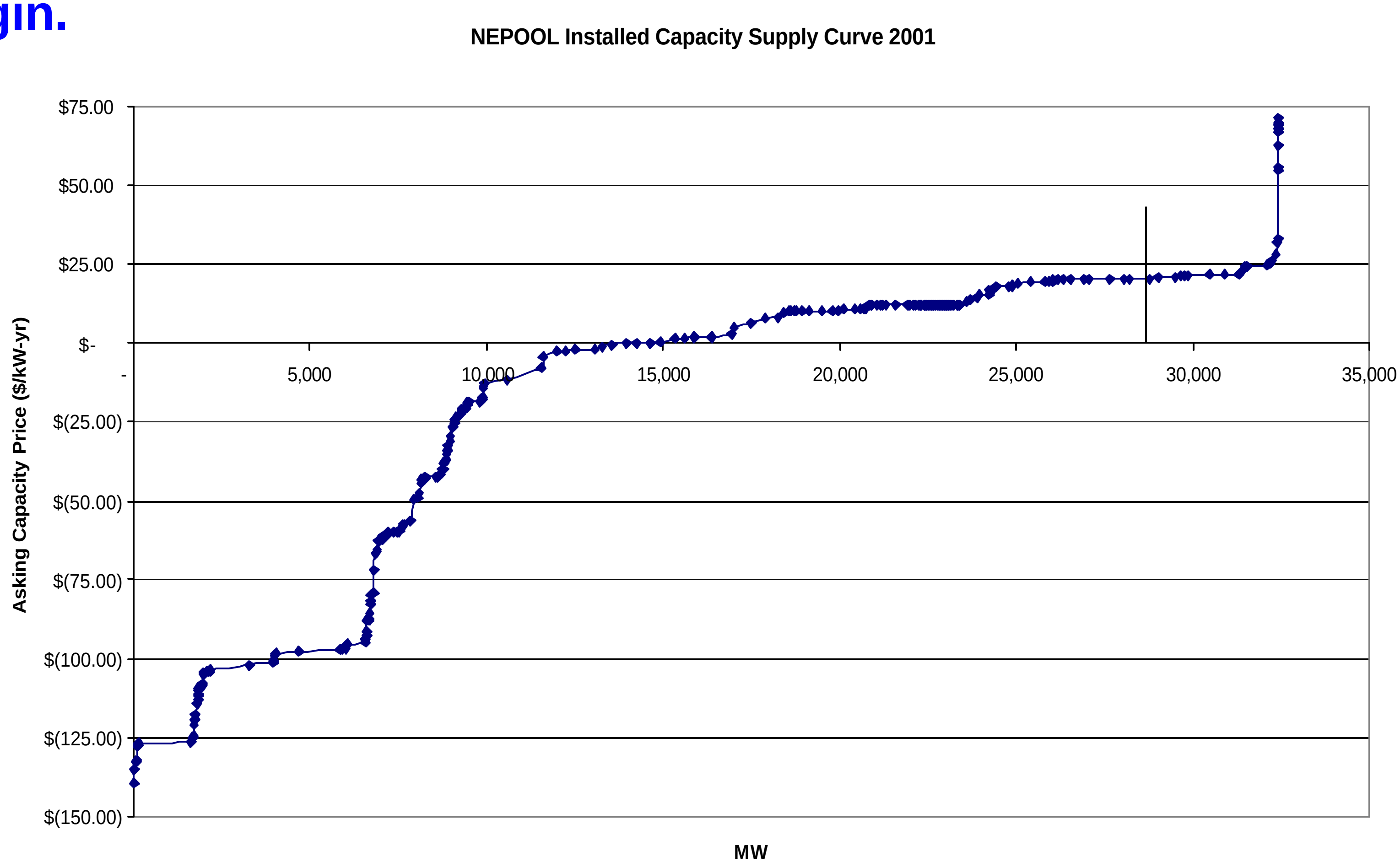
Forecasting Installed Capacity Market Prices

Installed Capacity value will be reflected either in an installed capacity market, or in its absence in the reserves and energy markets.

- Installed capacity prices value will be reflected only in peak months, and generally equal the penalties/price caps on capacity deficiencies.
- New entry in all markets will cause a substantial drop in capacity prices over the next 4-5 years.
- Thereafter, in an equilibrium market annual capacity prices will generally equal the carrying cost of a new unit (gas-fired combined cycle) less its energy revenues.
- Installed capacity can be traded across RTOs (with some limitations).

Forecasting Capacity Market Prices

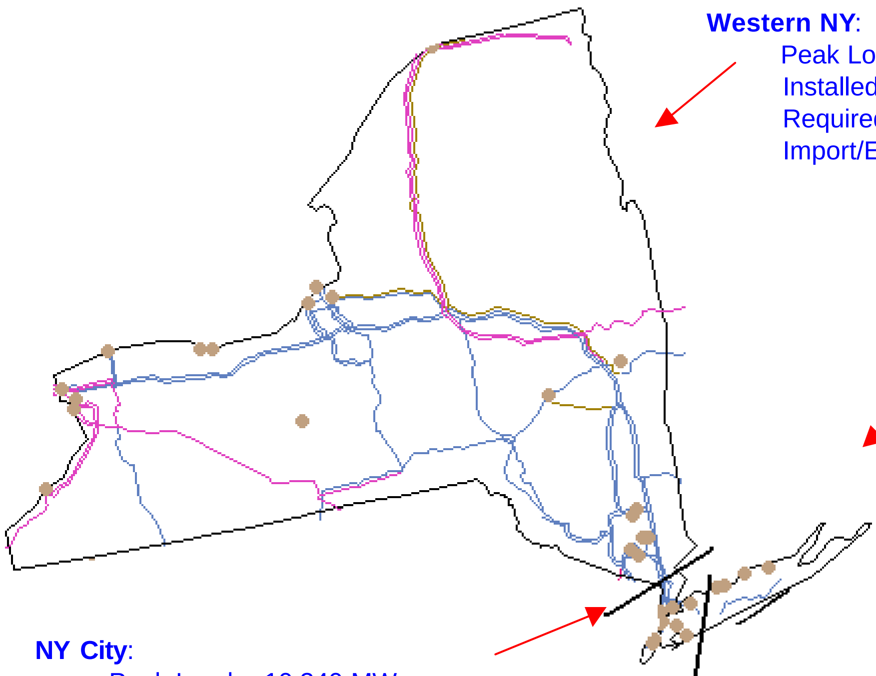
We forecast capacity prices based on the residual marginal operating cost of the last unit required to meet the reserve margin.



Locational Capacity Markets - NYPP 2000

The NY ISO has proposed three regional capacity markets and has minimum requirements on installed capacity in New York City (80% of peak load) and Long Island (104% of peak load).

Western NY:
Peak Load = 15,500 MW
Installed Capacity = 22,700 MW
Required Capacity = 14,738 MW
Import/Export = -4,600 MW



Long Island:
Peak Load = 4,350 MW
Installed Capacity = 4,410 MW
Required Capacity = 4,638 MW
Import/Export = 1,050 MW

Generating Plants
230 kV Lines
345 kV Lines
500 kV Lines
765 kV Lines

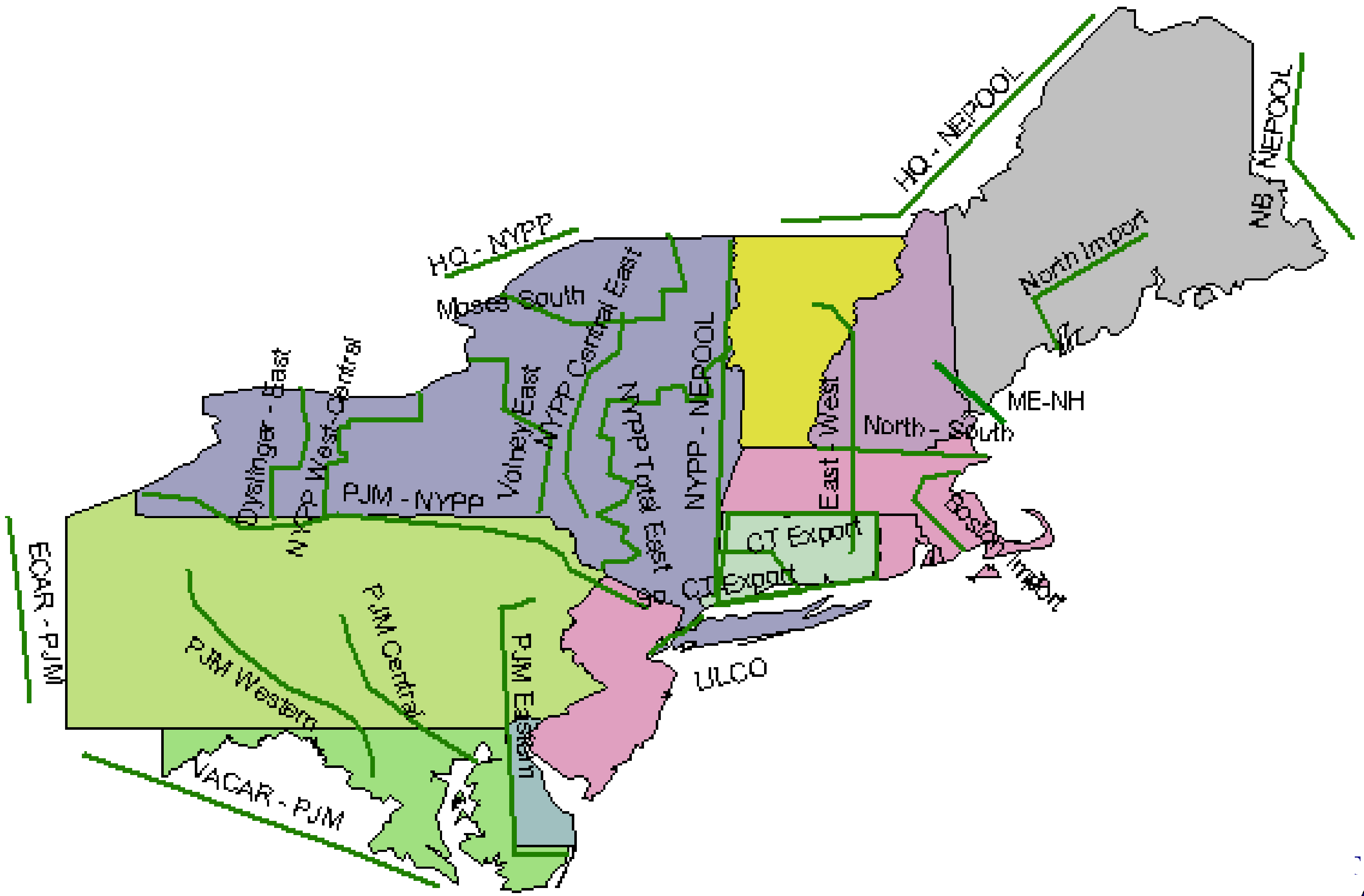
NY City:
Peak Load = 10,340 MW
Installed Capacity = 8,000 MW
Required Capacity = 8,272 MW
Import/Export = 4,600 MW

Transmission Rights

In electricity and specifically in the Northeast, transportation is purchased 'point-to-point' rather than on individual links.

- TCCs (FTRs) are financial hedges against transmission congestion between the sending and receiving ends, they are rights to the congestion cost.
- The value of a TCC equals the difference in LBMP between the sending and receiving ends.
- TCCs do not provide physical delivery guarantee but rather give the right holder the equivalent of financial delivery guarantee.
- The holders of firm transmission service will have TCC equivalent to the original firm service.
- All transactions are firm as long as they pay the congestion cost.

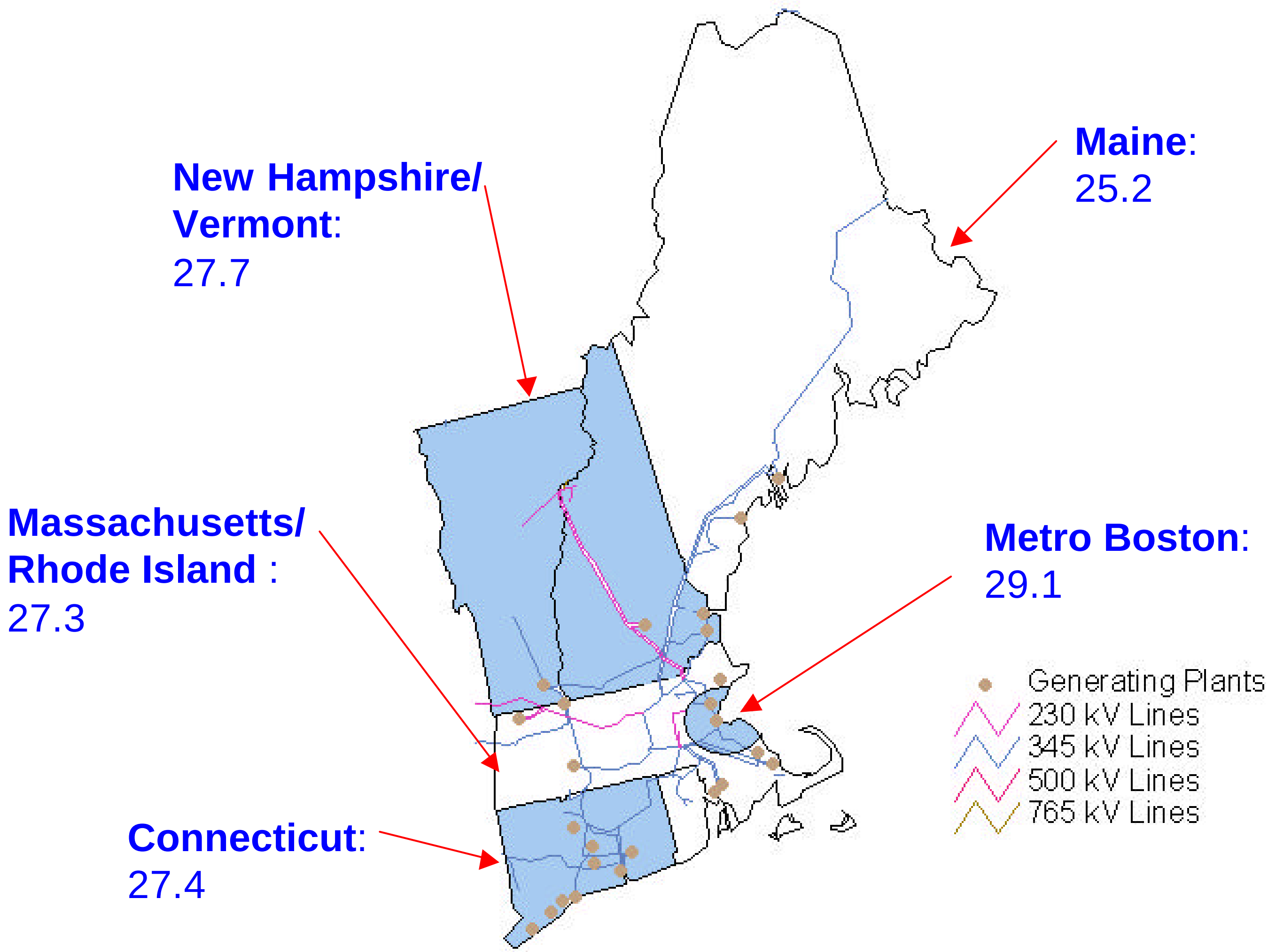
Northeast Major Transmission Interfaces



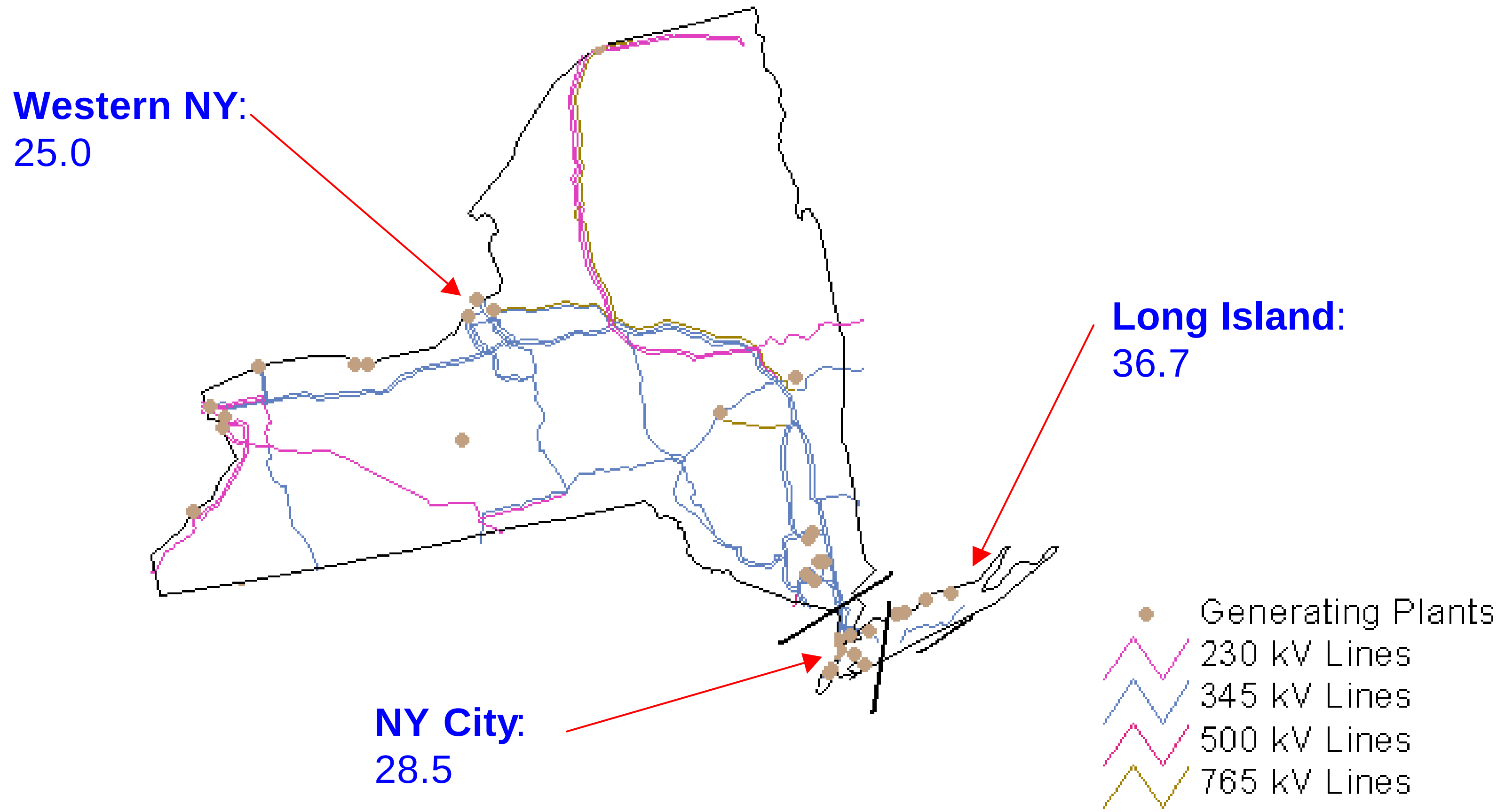
Transmission Congestion

- **NYPP: Congestion across the Central East interface is high in 2000, but is reduced significantly by 2003 due to new entry.**
- **NEPOOL: Congestion results in higher prices in Connecticut, and eastern Massachusetts relative to other parts of NEPOOL.**
- **PJM: Eastern PJM generally have higher energy prices, this differential diminishes in the future.**

New England Illustrative Locational Energy Prices ($/MWh)

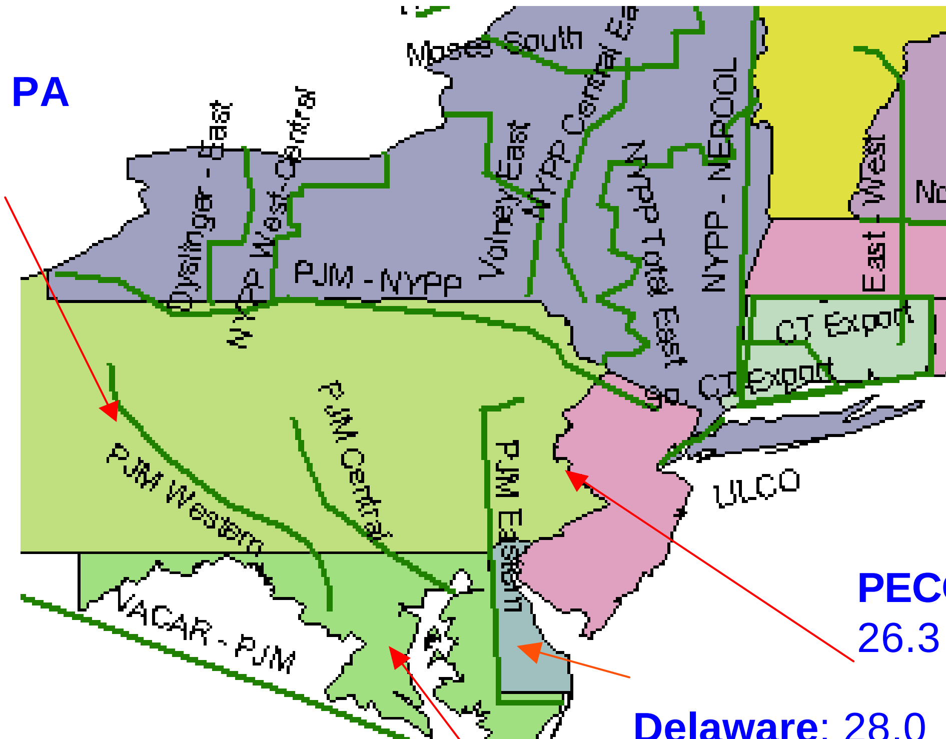


New York Illustrative Locational Energy Prices ($/MWh)



PJM Illustrative Locational Energy Prices ($/MWh)

West PA
25.4



PECO, NJ
26.3

Delaware: 28.0

Baltimore:
26.8

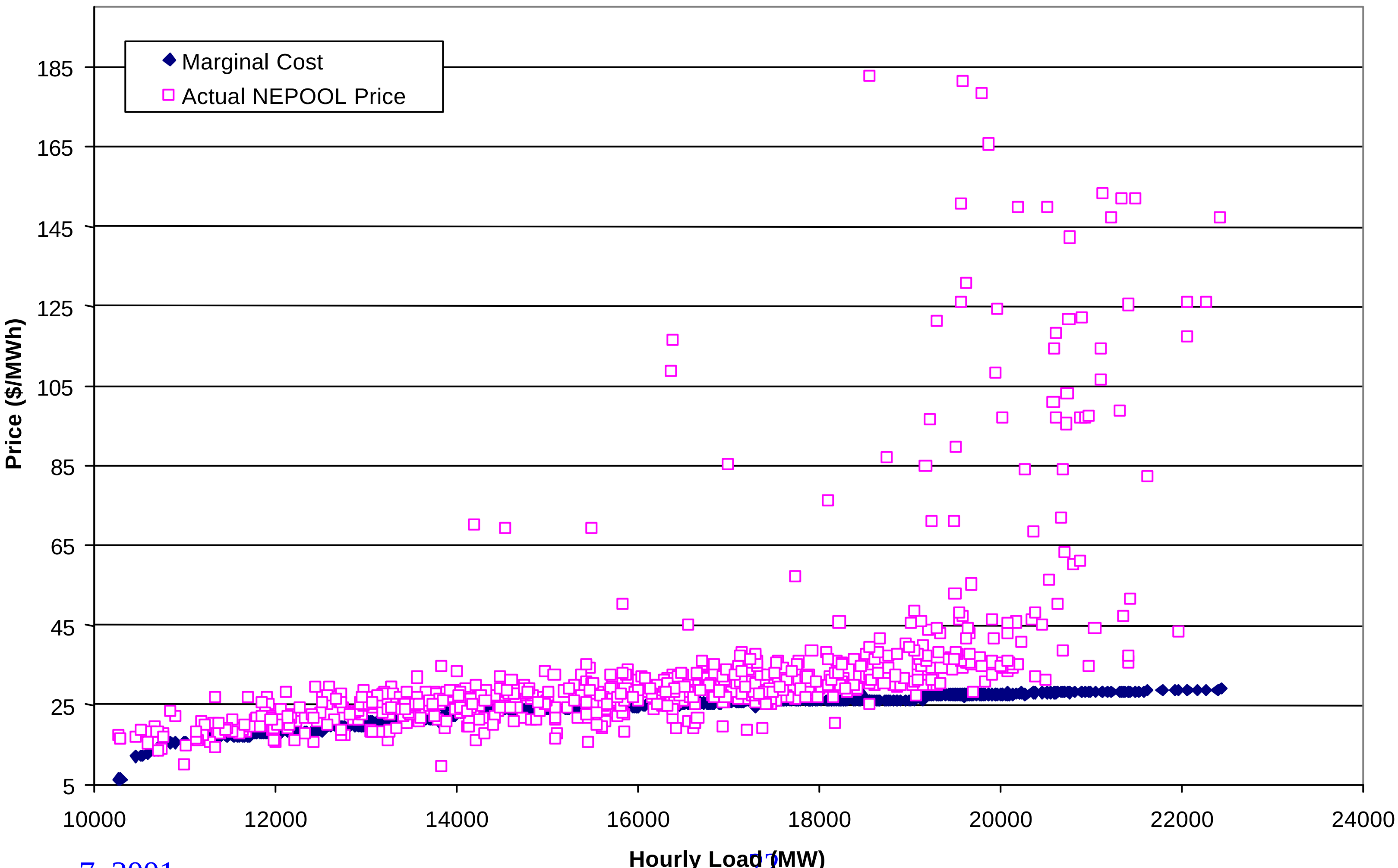
Strategic Bidding

Perfectly competitive markets exist only in theory. Generation companies are likely to maximize their profits, and manage risk using one of several strategies:

- Bidding up to the marginal cost of the next unit in the merit order.
- Withhold capacity from the market.
- Implicit collusion and non-cooperative oligopoly

Strategic Bidding

Market Clearing Prices vs. Marginal Costs. NEPOOL, July-1999
(15 hourly prices in excess of $200/MWh are not shown)



Simulating Strategic Behavior

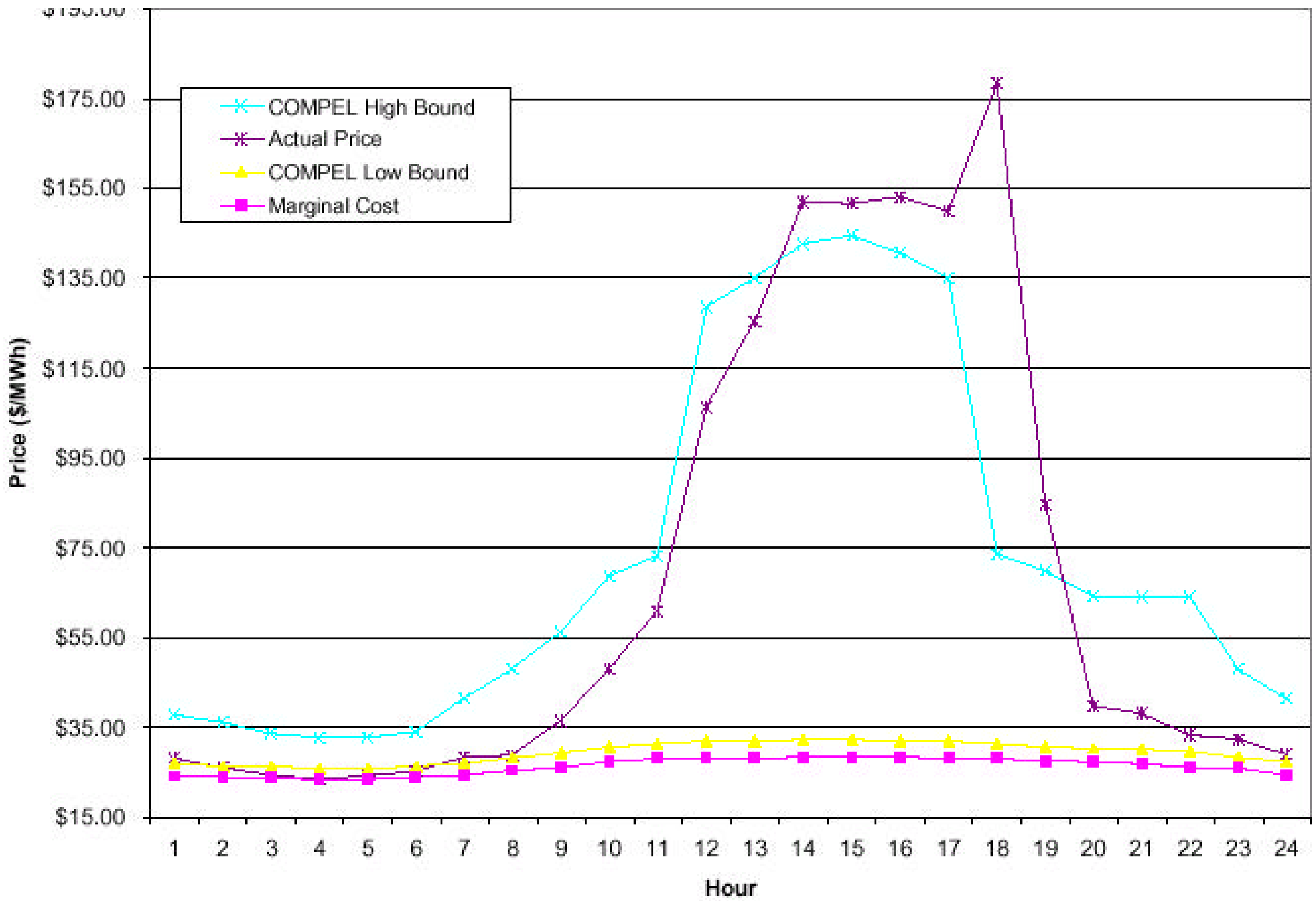
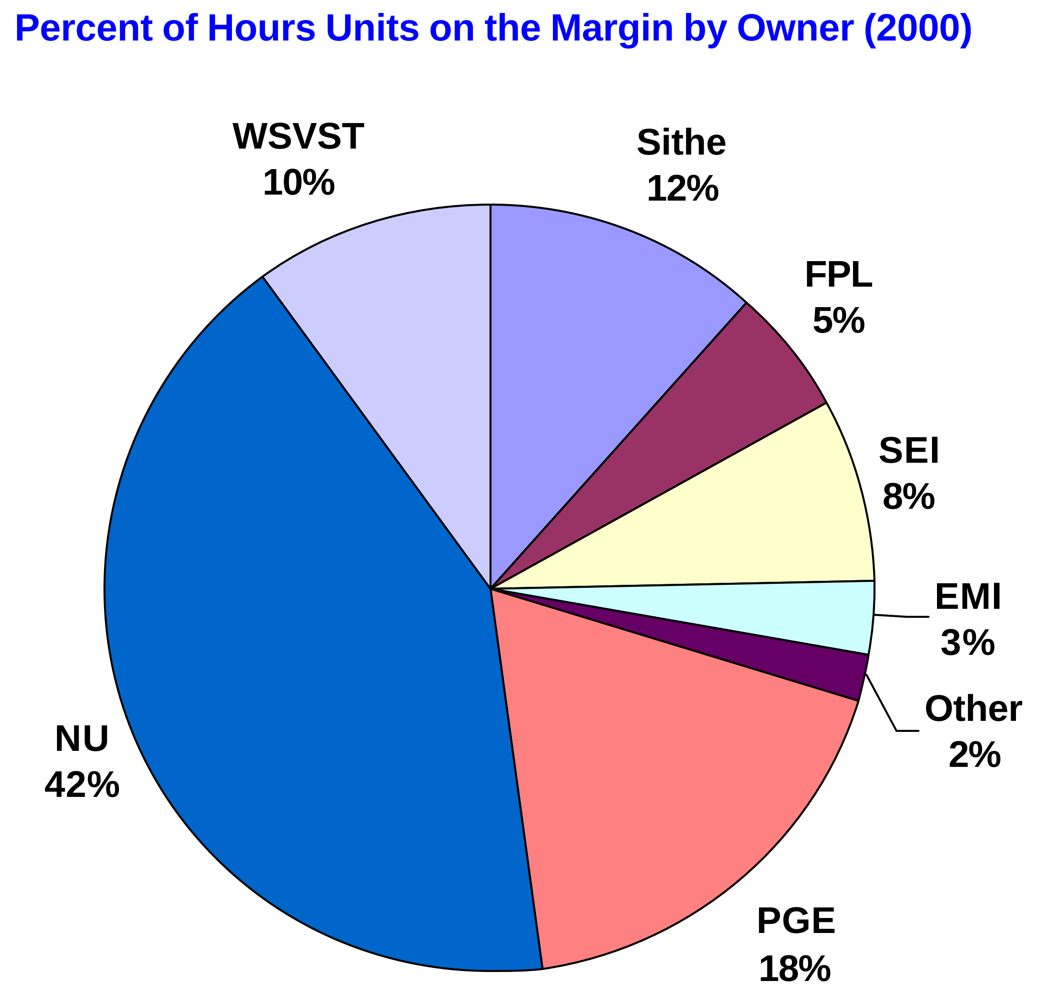


Figure 3. Actual Prices vs. Prices Simulated by COMPEL™ for July 30, 1999

Example of Marginal Units Ownership (2000)

Ownership patterns show the potential for such behavior.



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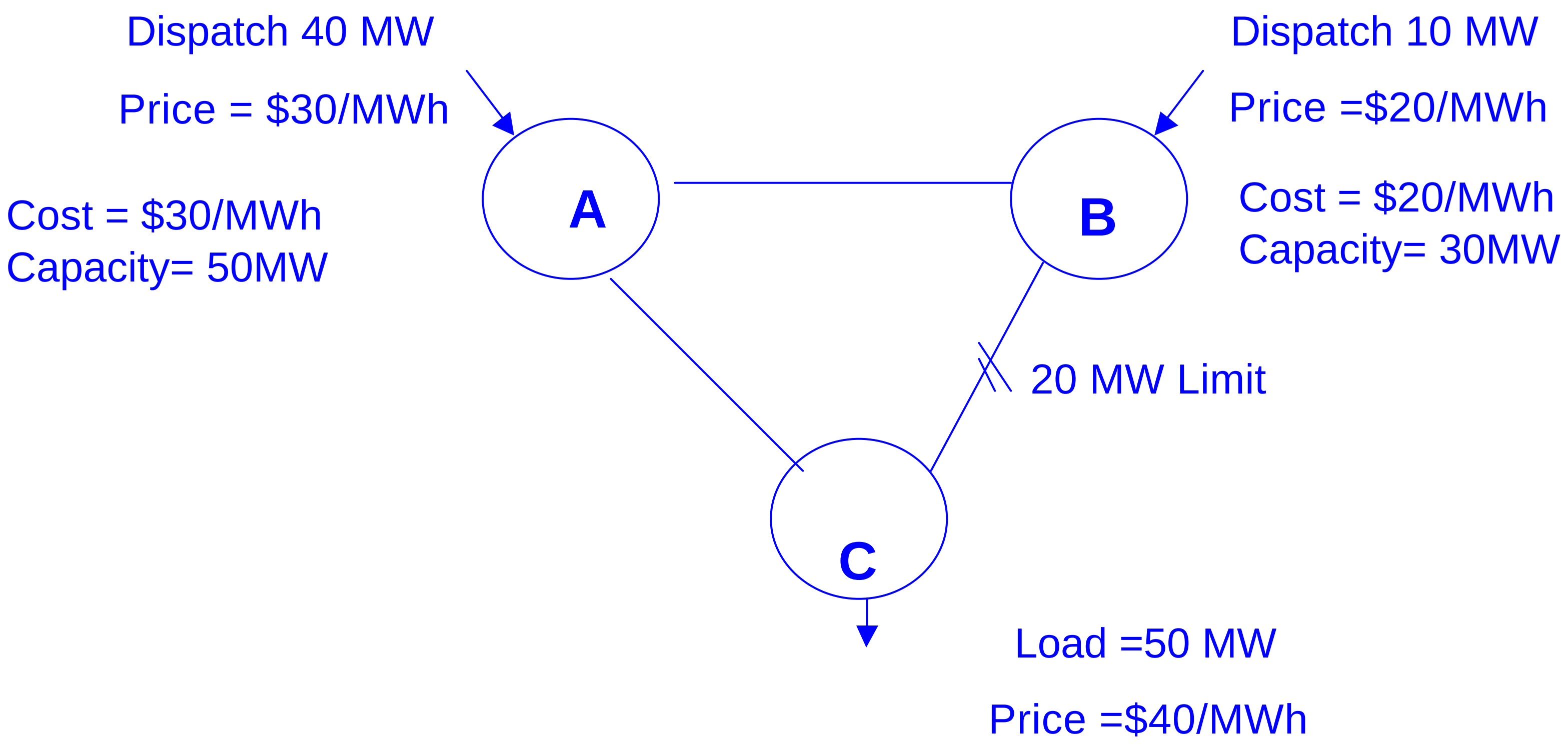
Forecasting Energy Market Prices

Although generators bid marginal costs, nodal spot prices can be higher than the cost of the most expensive unit running, or negative.



The Mathematical Model

The model can be mathematically described as follows:

Minimize Total Cost = $\sum_{i \in I} GenCost_i * Gen_i$

Subject to:

(1) $Gen_i \leq MaxCap_i \quad \forall i \in I$

(2) $\sum_{i \in I} Gen_i = \sum_{a \in A} Load_a$

(3) $PowerFlows_l \leq MaxFlows_l \quad \forall l \in L$

(4) $PowerFlows_l \geq MinFlows_l \quad \forall l \in L$

(5) Operating Reserves

MAPS Model Inputs

Thermal Characteristics
- **Units Summer and Winter capacities**
- **Units heat rates, fuel types & outages**
- **Units variable operation and maintenance cost by unit type and size**

Hydro Unit Characteristics
- **Hydro and pump storage generation levels**

Fuel Prices
- **Fuel prices for each geographic area**

Transmission System Representation
- **Transmission constraints**

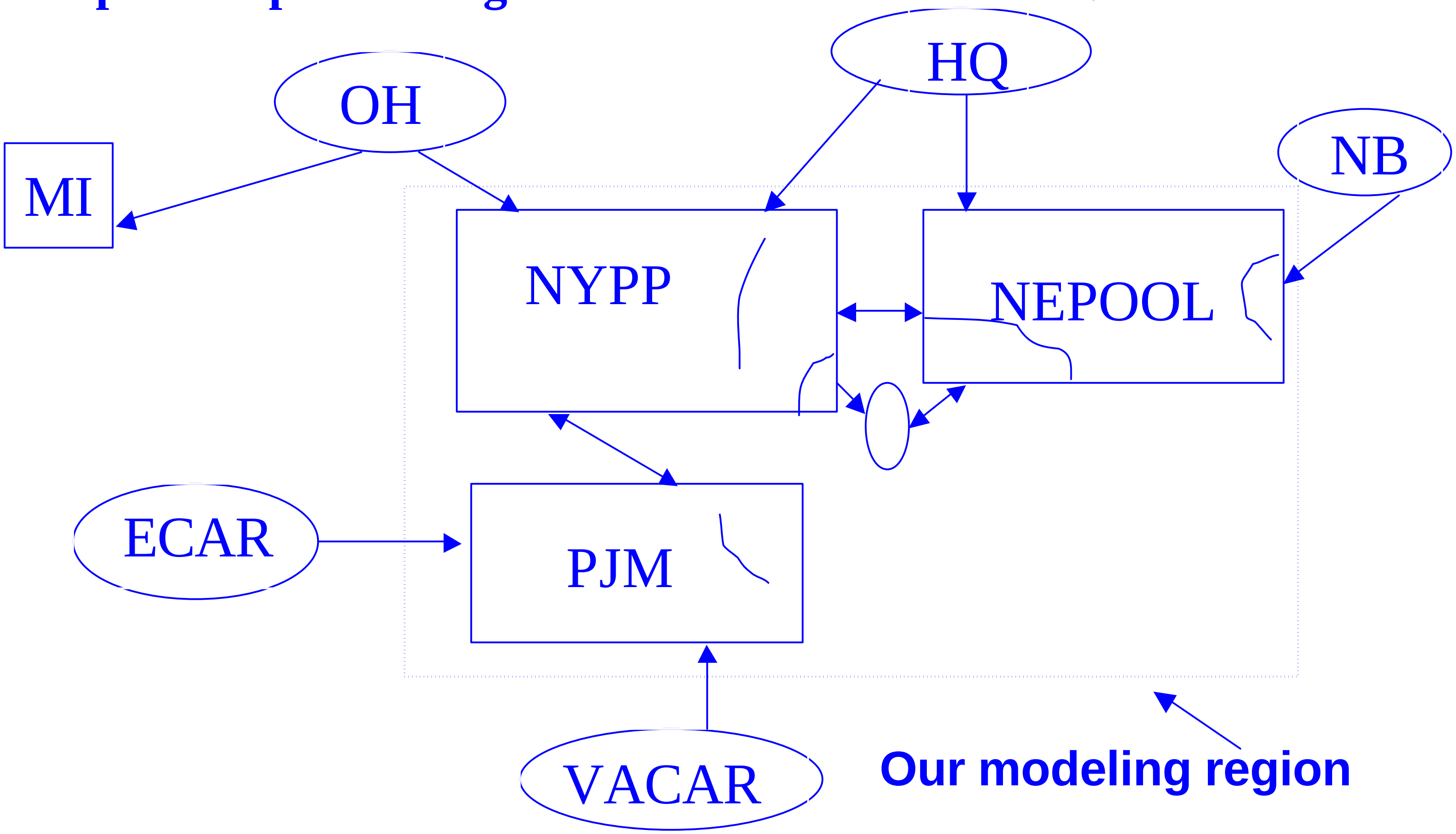
External Supply Curves
- **Imports and exports from outside the Northeast system**

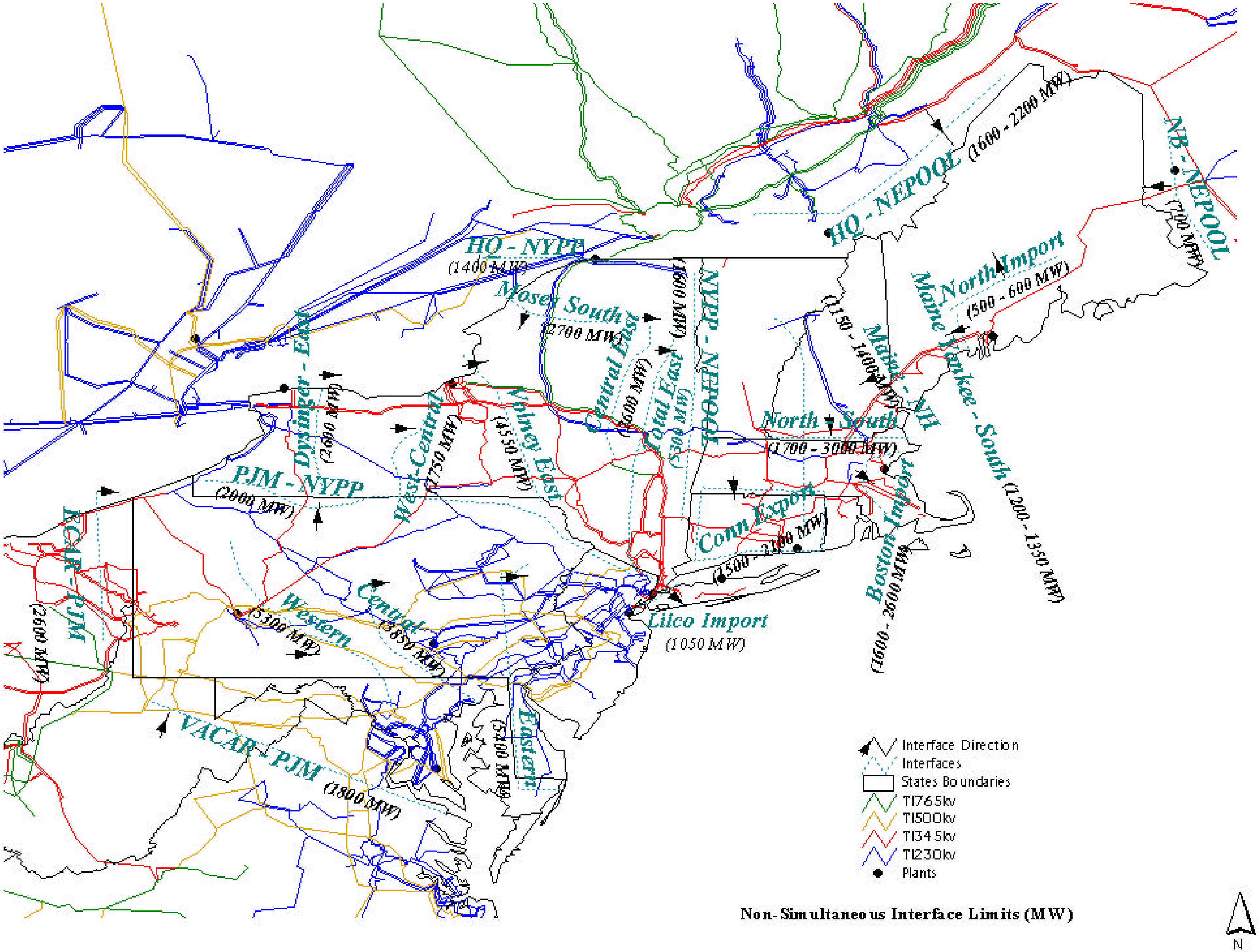
Load Requirements
- **Forecasted peak load and hourly shape, and dispatchable demand**
- **Reserves requirements**

Economic Entry and Retirements

The MAPS Physical Model

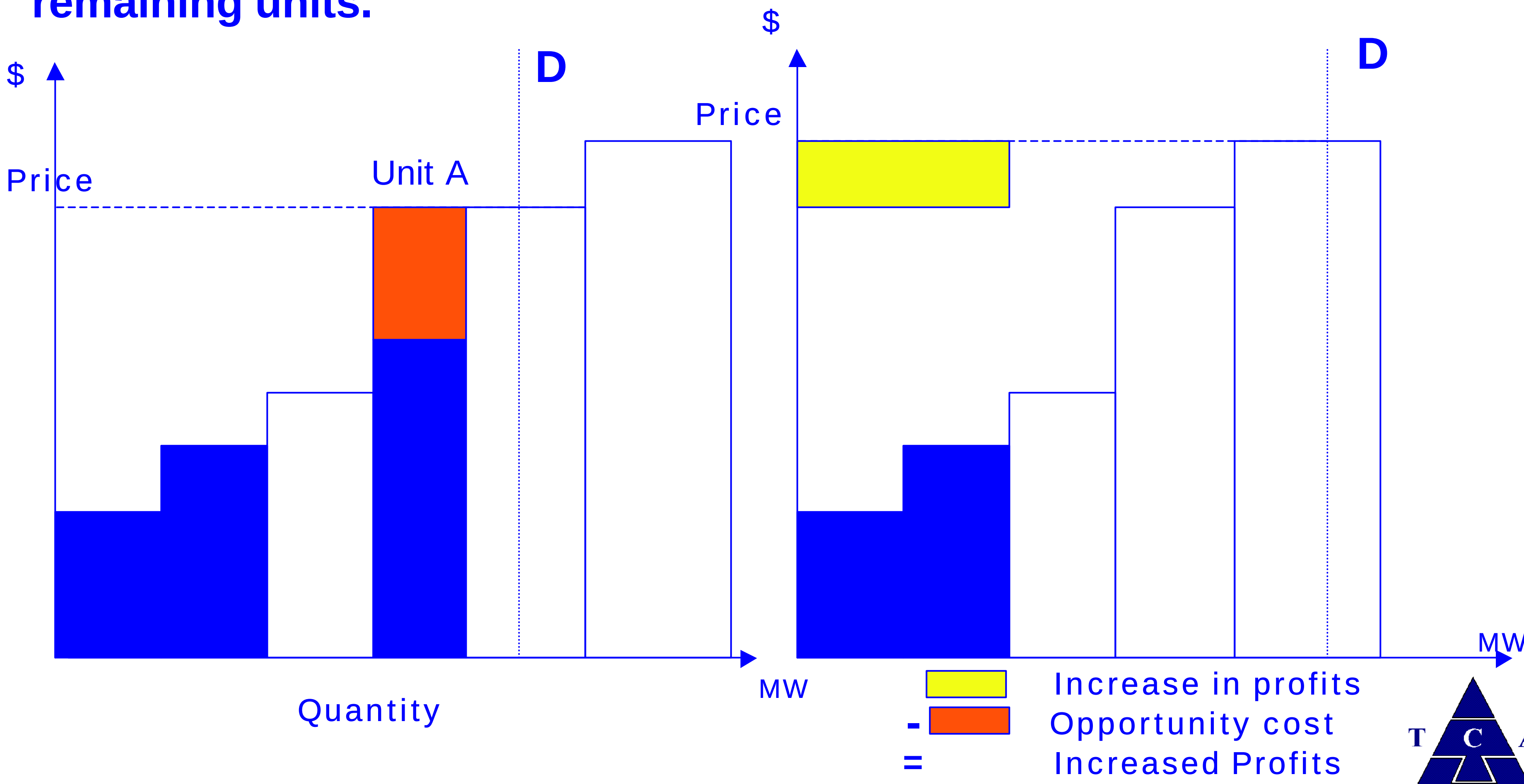
We model the outside world as supply curves in order to simulate imports and exports as per existing contracts or historical flows.




HQ - NYPP
(1400 MW)
Moses South
(2700 MW)
Central East
(3600 MW)
Total East
(5300 MW)
(1600 MW)
NYPP - NEPOOL
HQ - NEPOOL
(1600 - 2200 MW)
NB - NEPOOL
(700 MW)
North Import
(500 - 600 MW)
Maine Yankee - South
(1200 - 1350 MW)
Maine - NH
(1150 - 1400 MW)
North South
(1700 - 3000 MW)
Boston Import
(1600 - 2600 MW)
Conn Export
(1500 - 2100 MW)
Lilco Import
(1050 MW)
Dysinger - East
(2600 MW)
West-Central
(1750 MW)
Volney East
(4550 MW)
PJM - NYPP
(2000 MW)
ECAR - PJM
(2600 MW)
Western
(5300 MW)
Central
(3850 MW)
Eastern
(5400 MW)
VACAR - PJM
(1800 MW)
Interface Direction
Interfaces
States Boundaries
TI765kv
TI500kv
TI345kv
TI230kv
Plants
Non-Simultaneous Interface Limits (MW)
N

Strategic Bidding - Strategies

Company "Blue" can strategically withhold capacity (unit A) to increase prices, and therefore increase revenues earned by its remaining units.



Game Theory – Simulating Strategic Behavior

- **Nash: A player maximizing its own payoff given the strategies followed by all opposing players (General equilibrium)**
  - **Cournot: Set of outputs for which each firm maximizes profit given the *outputs* of the remaining firms**
  - **Bertrand: Set of outputs for which each firm maximizes profit given the *prices* of the remaining firms**
  - **Supply Function: Set of outputs for which each firm maximizes profit given the *supply curves* of the remaining firms**
- **TCA uses Supply Function Equilibria algorithms in COMPEL to simulate strategic behavior.**