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***Too Little Money:
Designing Markets to Ensure Adequate Capacity
Policy, Economics and Market Performance***

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Discussion Topics

- *Introduction*
- *Too much money? Market performance 2000-2002*
 - *Compensation for new entrants*
 - *Spot prices during scarcity*
- *Too little money. Why capacity matters*
- *Policy options to ensure adequate reserves*
 - *Reserve-requirements system*
 - *Energy-only pricing system*
- *The Northeast ISOs' JCAG proposal*
- *FERC's Reserve Adequacy Requirement*
- *The FERC staff paper on forward reserve contracts*

Too Much Money?

Market Performance

- *2000-2002 Northeast ISO actual spot prices below cost of entry, despite:*
 - *Real scarcity events and extreme weather*
 - *Very tight reserve margins*
 - *Clear need for new entry*
- *2000-2002 capacity market revenues were insufficient to make up the difference.*

Implications

- *No market power (materiality and sustainability)*
 - *Spot energy prices in a workably competitive market should have been above – and perhaps significantly above – the cost of entry in 2001 and 2002.*
 - *As a matter of economics, a market needing new entry which has prices below the cost of entry is devoid of market power by definition.*
- *Loss of investor confidence in energy supply business*
 - *If market prices fail to compensate a new entrant when demand is extreme and capacity is tight, they are even less likely to provide adequate compensation in the long term when demand is normal and new entry has occurred*

Not Enough Money Policy Implications

Price Setting Rules

- *Scarcity Pricing*
 - *Change ISO pricing rules to implement good, efficient pricing under scarcity and stop suppressing scarcity signals.*
- *Minimize side payments to marginal generators due to non-compensatory prices (i.e. have spot prices reflect the real cost of serving load, including start-up and min gen)*

Market Mitigation

- *\$1,000 bid caps may be too low*
 - *Some generators have costs for emergency output that are greater than \$1000*
 - *Some loads would curtail at prices above \$1000*
 - *Value of Lost Load is higher than \$1000.*
- *Automatic mitigation (AMP) not justified except in constrained load pockets. FERC SMD NOPR criteria got this approximately right.*
 - *“voluntary fourth measure that could apply in **unusual market conditions** to assure that the high prices are not the result of market power.” [NOPR at P. 398].*
 - *“Exercise of this mitigation could be triggered by predetermined conditions or triggers (such as a sustained period of prices significantly above competitive levels), or by significant infrastructure problems in the market (e.g. sustained tight reserve conditions, as might be due to drought).” [NOPR at P. 402].*
 - *“Since this form of market power mitigation is for temporary market conditions, it will be equally important for the market monitor to indicate the criteria to determine when the market has returned to normal competitive conditions and this market power mitigation method will be suspended.” [NOPR at P. 416].*

Not Enough Money Policy Implications

Capacity Markets

- *A competitive market could work without capacity payments.*
 - *But this would require far greater tolerance of price spikes and high spot prices, and less aggressive mitigation.*
 - *The political will to support such high energy prices is demonstrably absent.*
- *Capacity payments are needed as long as we have pricing rules that:*
 - *Mask scarcity and suppress prices in non-scarcity hours through use of side-payments / uplift to marginal generators that are committed and do not recover their cost.*
 - *Do not reflect appropriate payments to units providing operating reserve to the system.*
 - *Have aggressive mitigation that prevents prices from rising during scarcity.*
- *Capacity markets have been poorly designed in the Northeast, but can be designed well.*
 - *Should provide long-term entry signals (current markets are too short-term)*
 - *Must be compatible with retail competition*
 - *Must avoid “free riders” through adequate enforcement mechanisms*
 - *Northeast ISOs have developed a proposal through JCAG*



Too Much Money? Evidence From Market Performance in Northeast ISOs:

- **Annual Compensation for New Generators**
- **ISO Price-setting During Scarcity**

Market Performance

- *LMP systems of NYISO and PJM are the starting point for well-design RTO markets*
- *In designing RTOs, and improving ISO energy markets in the Northeast, it is essential that policy-makers assess market performance.*
 - *The markets have been going for a while.*
 - *How are they doing?*
- *Market performance assessment based on answers to two questions:*
 - *Is entry needed?*
 - *Is entry economic without capacity payments?*

Market Performance

- *2001 and 2002 represent excellent test cases for market performance in the Northeast ISOs. Both years had:*
 - *Tight capacity margin on annual basis in ISO-NE, NY, and PJM.*
 - *Extremely hot weather, leading to multiple days with supply scarcity, and other high demand days.*
 - *Given these circumstances, one may expect prices to be above – perhaps significantly above – the cost of entry in a functioning, workably competitive market.*
 - *2000 is a worse test case as cool Summer weather resulted in fewer scarcity conditions in NYISO and ISO-NE.*
- *If market prices do not compensate a new entrant when demand is extreme and capacity is tight, they are even less likely to provide adequate compensation when demand is normal or low and new entry has occurred.*
- *The predictable result would be loss of investor confidence in the energy supply business.*



Market Performance

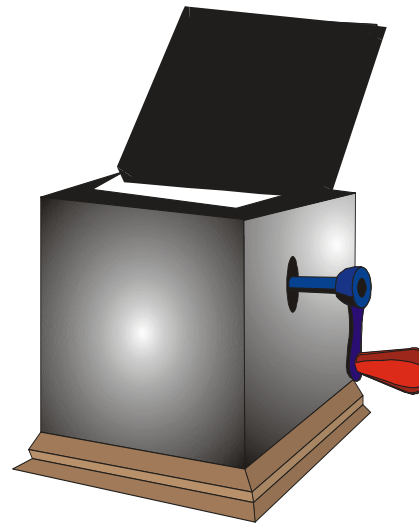
Was Entry Needed in 2001/2002?

- *NYISO*
 - *Continuing well-publicized “Statewide Energy Crisis”*
 - *Shortfall in generation during 2001 peak week – a 1 in 15 year heat wave*
 - *During 2002, EDRP was called on two occasions.*
- *ISO-NE*
 - *2001:*
 - 10% reserve margins; extremely tight*
 - 2 separate generation shortages (OP-4 emergency procedures activated): 7/25 and 8/9*
 - *2002:*
 - While expected reserve margins were higher than 2001, extreme weather and delays in the installation of new generation led to scarcity conditions.*
 - 6 days of generation shortage (OP-4)*
- *PJM*
 - *Voltage reduction and load shedding (2400 MW) during peak of 2001, which occurred on several days.*
 - *3 Events of load management curtailment in 2002*
 - *Very tight capacity margin in 2001 and 2002.*
- *Implications:*
 - *Spot energy prices in a workably competitive market should have been above – and perhaps significantly above – the cost of entry in 2001 and 2002.*
 - *While ISO-NE and PJM may be entering oversupply conditions in the near future, which could lead to competitive prices appropriately below the cost of entry in the future, this oversupply did not exist in 2001 and 2002. These years had very tight supply/demand conditions.*

Entry Cost

- *New CC entrants need to earn sufficient revenue (energy, ancillary services, capacity) to recover the cost of entry.*

| <u>Finance Assumptions</u> | |
|-----------------------------------|--------------|
| • Installed cost: | \$600-700/kw |
| • Project Life: | 30 years |
| • Tax Life: | 20 years |
| • Debt Life: | 20 years |
| • Tax rate: | 38.9% |
| • Debt/equity: | 50/50 |
| • Debt rate: | 9% |
| • Return of Equity: | 13.5% |
| • Fixed O&M: | \$15/kw-yr |



**Simple Pro Forma
Financial Model**

| <u>Annual Revenue Requirement</u> | |
|--|--------------------|
| High: | \$120/kw-yr |
| Low: | \$105/kw-yr |

- *The estimated revenue requirement is the “average” annual return each year.*
 - *The “good” years need to be higher to make up for the “bad” years which will invariably be lower.*
 - *If the “good” year is capped at the levelized return, the unit can never recover its cost of entry in the long run, because there is no “floor” in the bad years.*
- *Consistent with E-Acumen study of entry cost for ISO-NE -- \$74/kw-yr for a peaker (CC is higher cost than simple CT).*

2000-2002 Energy-only Revenue of Merchant CC

- 7100 btu/kW CC optimally dispatched against 2001/2002 actual market prices in eastern NYISO (Zone G DAM), eastern PJM (PECO zone DAM), and NEPOOL (ECP).
- How much would the new unit earn from day-ahead energy-only revenues in 2000-2002 (\$/kw-yr)?
 - ISO-NE

| | |
|-------|------|
| 2000: | 75.9 |
| 2001: | 72.2 |
| 2002: | 61.2 |
 - NYISO Zone G

| | |
|-------|------|
| 2000: | 78.3 |
| 2001: | 79.6 |
| 2002: | 73.6 |
 - PJM PECO Zone

| | |
|-------|------|
| 2000: | 30.1 |
| 2001: | 53.4 |
| 2002: | 44.2 |
- Revenue Requirement from previous slide: \$105-120/kw-yr, each year (but the “good” years should be even higher).

2000-2002 Energy-only Revenue of Merchant CC

Summary of Ex-post Optimal Dispatch Model -- Performance of Entrant Combined Cycle Unit

| Pool / Year | All-hours Average Price (\$/MWh) | Average Revenue (\$/MWh) | Average Cost (\$/MWh) | Average Energy Margin (\$/MWh) | Average Energy Margin (\$/kw-yr) | Levelized Entry Cost (\$/kw-yr) | Levelized Return (\$/kw-yr) | Capacity Factor |
|-------------------------|----------------------------------|--------------------------|-----------------------|--------------------------------|----------------------------------|---------------------------------|-----------------------------|-----------------|
| ISO-NE | | | | | | | | |
| 2000 | 43.2 | 48.0 | 35.0 | 13.1 | 75.9 | 115.0 | (39.1) | 66% |
| 2001 | 40.2 | 42.7 | 29.8 | 12.9 | 72.2 | 115.0 | (42.8) | 64% |
| 2002 | 32.2 | 35.3 | 25.5 | 9.8 | 61.2 | 115.0 | (53.8) | 71% |
| NYISO Zone G DAM | | | | | | | | |
| 2000 | 44.8 | 49.9 | 35.1 | 14.8 | 78.3 | 115.0 | (36.7) | 60% |
| 2001 | 41.9 | 43.4 | 29.4 | 14.0 | 79.6 | 115.0 | (35.4) | 65% |
| 2002 | 35.0 | 37.5 | 26.4 | 11.1 | 73.6 | 115.0 | (41.4) | 75% |
| PJM PECO Zone | | | | | | | | |
| 2000 | 29.2 | 52.3 | 37.4 | 14.9 | 30.1 | 115.0 | (84.9) | 23% |
| 2001 | 33.6 | 42.3 | 28.0 | 14.3 | 53.4 | 115.0 | (61.6) | 43% |
| 2002 | 27.8 | 36.2 | 25.3 | 11.0 | 44.2 | 115.0 | (70.8) | 46% |

Prices are ISO-NE ECPs, Zone G DAM, PECO Zone DAM

Cost assumptions for the hypothetical CC are as follows:

Gas prices as quoted daily by *Gas Daily* for the Tennessee Zone 6 (NE), Transco Zone 6 (NY), Texas-Eastern M3 (PJM)

4 percent State Taxes and 10 cents LDC charge added to *Gas Daily* daily price.

Full load average heat rate of 7100 btu/kw.

10% unit derating during Summer months.

\$60/MW per start start-up cost reflecting the both fuel cost and allocation of major maintenance.

\$1/MWh of VOM

5% forced outage rate.

No fixed maintenance schedule (adding this would lower energy margins)



Summary – 2000-2002

Energy-only Revenue of Merchant CC

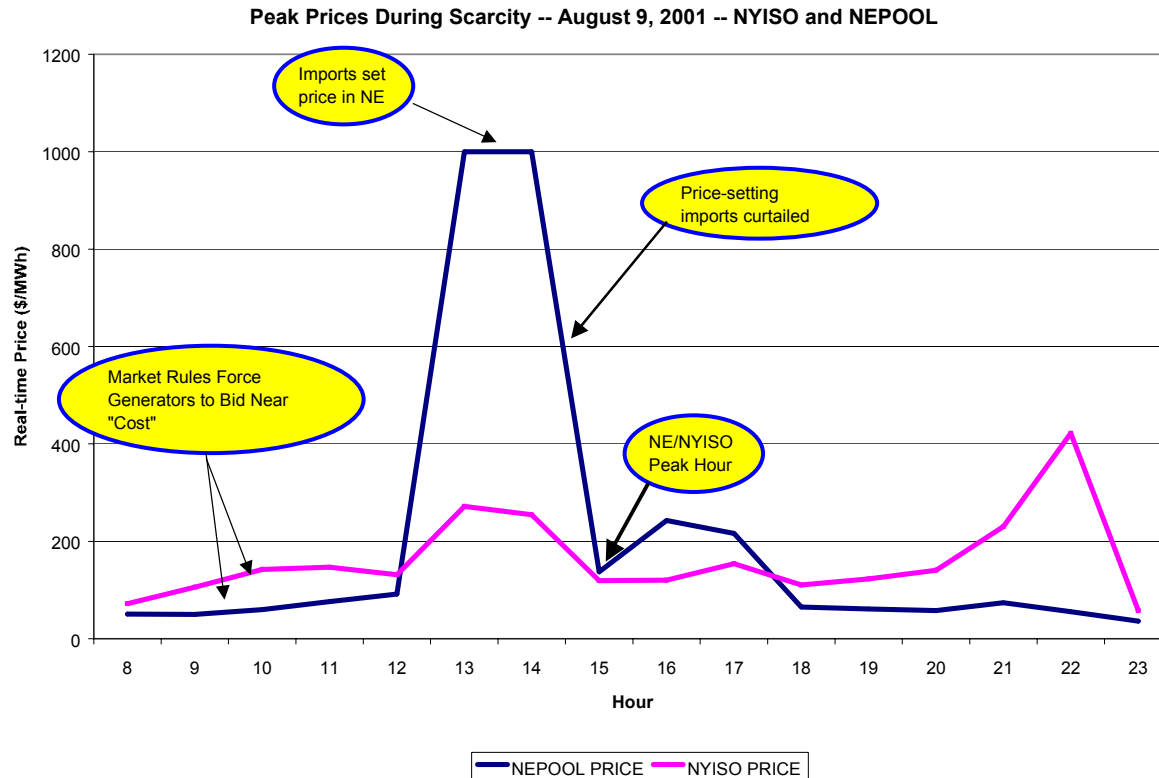
- *Despite need for new entry, energy margins are below amount needed to attract entry.*
- *ISO-NE*
 - *\$39-54/kw-yr shortfall annually (34-46% relative to entry cost)*
 - *Energy prices would need to increase by \$4.5-6.2/MWh, or 10-19 percent.*
- *NYISO*
 - *\$35-41/kw-yr shortfall annually (30-36% relative to entry cost)*
 - *Energy prices would need to increase by \$4.1-4.7/MWh, or 9-13 percent.*
- *PJM*
 - *\$62-71/kw-yr shortfall annually, excluding 2000's cool Summer (54-62% relative to entry cost)*
 - *Energy prices would need to increase by \$7.0-9.7/MWh, or 21-33 percent.*
 - *Margins are lower because the resource mix in PJM is has a greater proportion of lower-cost supply (coal and nuclear).*

Summary – 2000-2002 Including Capacity Payments

- Capacity payments are insufficient in each of the Northeast ISOs.
- In PJM, the price cap in the capacity market is less than the required make-whole payment.

| Performance of Entrant Combined Cycle Unit; Energy and Capacity Payments | | | | | | | |
|--|----------------------------------|--|--|---------------------------------|--|---|--|
| Pool / Year | Average Energy Margin (\$/kw-yr) | Capacity Payment (Historical Spot Data) \$/kw-yr | Capacity Payment (Current Forward Market) \$/kw-yr | Levelized Entry Cost (\$/kw-yr) | Levelized Return with Historical Capacity Price (\$/kw-yr) | Levelized Return with Forward Capacity Price (\$/kw-yr) | |
| ISO-NE | | | | | | | |
| 2000 | 75.9 | - | 8.4 | 115.0 | (39.1) | (30.7) | |
| 2001 | 72.2 | - | 8.4 | 115.0 | (42.8) | (34.4) | |
| 2002 | 61.2 | - | 8.4 | 115.0 | (53.8) | (45.4) | |
| NYISO Zone G DAM | | | | | | | |
| 2000 | 78.3 | 11.1 | 15.0 | 115.0 | (25.6) | (21.7) | |
| 2001 | 79.6 | 19.6 | 15.0 | 115.0 | (15.9) | (20.4) | |
| 2002 | 73.6 | 19.8 | 15.0 | 115.0 | (21.6) | (26.4) | |
| PJM PECO Zone | | | | | | | |
| 2000 | 30.1 | 22.3 | 7.3 | 115.0 | (62.5) | (77.6) | |
| 2001 | 53.4 | 17.8 | 7.3 | 115.0 | (43.8) | (54.3) | |
| 2002 | 44.2 | 0.1 | 7.3 | 115.0 | (70.7) | (63.5) | |
| Energy Margins from Optimal Dispatch Model | | | | | | | |
| Capacity Spot Prices From ISO Web Sites of PJM, NYISO and ISO-NE | | | | | | | |
| PJM capacity prices are daily clearing prices. | | | | | | | |
| NYISO prices are Six-month Strip auctions | | | | | | | |
| ISO-NE cancelled the spot auctions for capacity in 2000, and has not administered spot capacity market since then. | | | | | | | |
| For the period, 2000-2001, capacity prices in ISO-NE were \$0, and no bilateral market existed. | | | | | | | |
| Capacity Forward prices are based on OTC broker quotes for Calander Year 2003 on 11/5/02. | | | | | | | |

Suppression of Prices Below Competitive Levels During Scarcity – 2001



- *ISOs price-setting software takes “unpriced” extreme measures.*
- *Many market flaws prevent prices from reaching competitive levels:*
 - *In this case, NYISO RT software ignored 30-min. reserve / deficient in 10-minute reserves*
 - *In ISO-NE only “externals” could bid near the cap in 2001. Thus, we find the bizarre result of prices collapsing when imports are curtailed and supply is reduced. In coming SMD, “externals” will be ineligible from setting prices.*
 - *ISO-NE peakers with costs above the price were run but were not eligible to set price because of market rules.*

2002 ISO-NE Prices Under Scarcity

25 OP-4 Hours

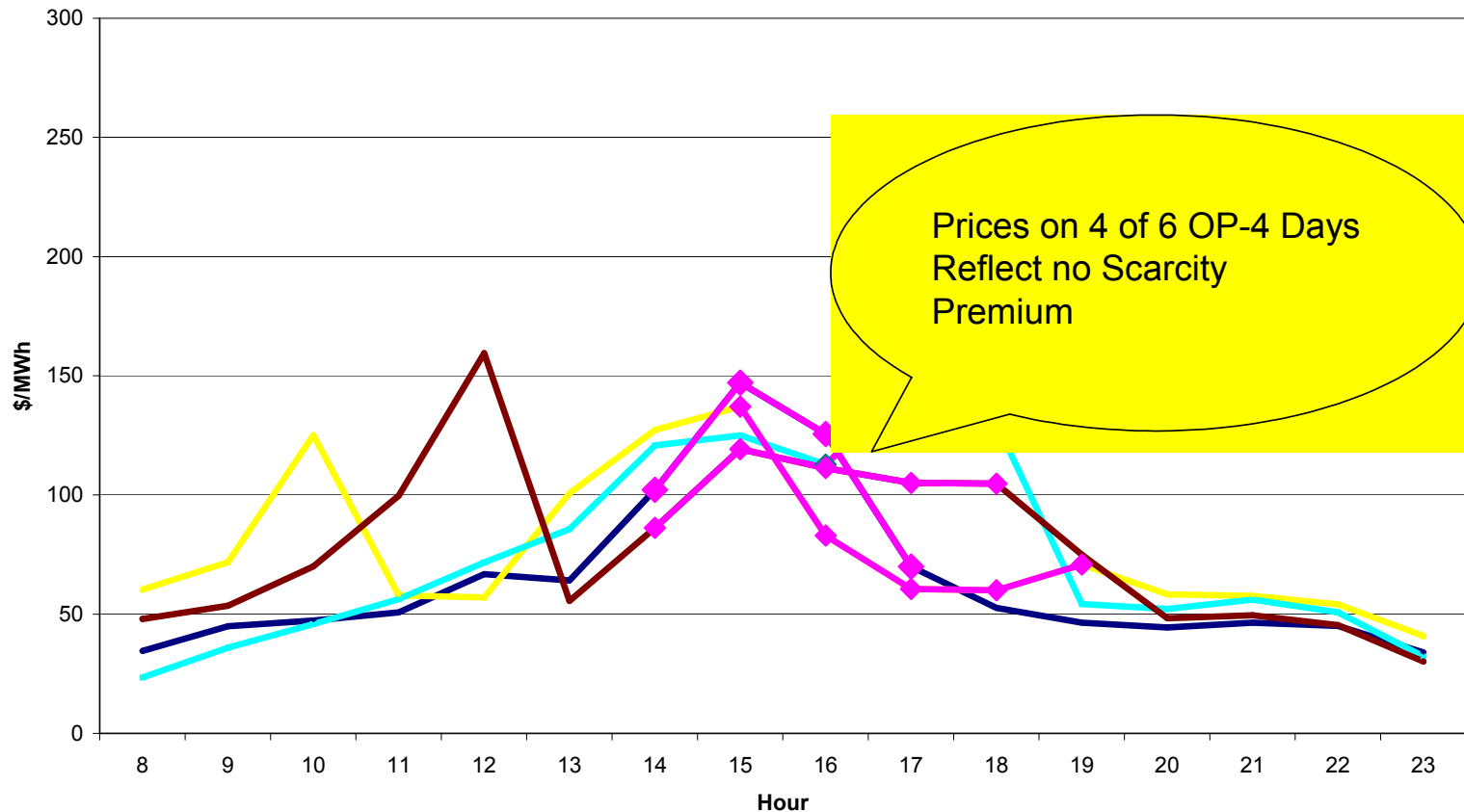
- In ISO-NE, “Patton” reforms implemented to improve scarcity pricing.
- Of the 25 OP-4 hours during 6 days in 2002:
 - 6 hours, or 24%, had prices below \$100/MWh with a minimum price of \$60 during capacity deficiency.
 - 17 hours (68%, more than 2/3 of the hours), had prices below \$150/MWh.
 - 8 hours (32%) had prices above \$150/MWh. All of these prices occurred on 2 of the 6 days with OP-4 hours.
- Thus, on 4 out of the 6 days with capacity deficiency in ISO-NE, the price never exceeded \$150/MWh and was frequently below \$100/MWh.

| 2002 ISO-NE Clearing Prices During Capacity Deficiency | | | |
|--|-----------|----------|-------------------------|
| Day | | Hour End | Clearing Price (\$/MWh) |
| | 6/26/2002 | 14 | 102 |
| | 6/26/2002 | 15 | 147 |
| | 6/26/2002 | 16 | 126 |
| | 6/26/2002 | 17 | 70 |
| | 7/23/2002 | 14 | 348 |
| | 7/23/2002 | 15 | 337 |
| | 8/5/2002 | 15 | 137 |
| | 8/5/2002 | 16 | 83 |
| | 8/5/2002 | 17 | 61 |
| | 8/5/2002 | 18 | 60 |
| | 8/5/2002 | 19 | 71 |
| | 8/13/2002 | 16 | 113 |
| | 8/13/2002 | 17 | 147 |
| | 8/13/2002 | 18 | 130 |
| | 8/14/2002 | 13 | 222 |
| | 8/14/2002 | 14 | 738 |
| | 8/14/2002 | 15 | 1,000 |
| | 8/14/2002 | 16 | 1,000 |
| | 8/14/2002 | 17 | 1,000 |
| | 8/14/2002 | 18 | 261 |
| | 8/19/2002 | 14 | 86 |
| | 8/19/2002 | 15 | 119 |
| | 8/19/2002 | 16 | 111 |
| | 8/19/2002 | 17 | 105 |
| | 8/19/2002 | 18 | 105 |

2002 ISO-NE Daily Peak Prices

4 of 6 OP-4 Days with Price Suppression

ISO-NE Peak Prices During OP-4 Days
Price Suppression During Scarcity



6/26/2002 8/5/2002 8/13/2002 8/19/2002 OP-4

2002 NYISO Daily Peak Prices July 30 and August 14

- *NYISO implemented Emergency Demand Response Programs (EDRP) on July 30 and August 14 2002. EDRP resources are paid \$500/MWh, and also receive capacity payments. When scheduled, they do not set price.*
- *On July 30*
 - *from 1 pm until 6 pm,*
 - *up to 689 MW of EDRP was called*
 - *Real-time prices during EDRP averaged \$86/MWh in New York City, indistinguishable from other typical Summer days in 2002.*
- *On August 14*
 - *from 1 pm until 6 pm,*
 - *up to 836 MW of EDRP was called*
 - *Real-time prices during EDRP averaged \$112/MWh in New York City, indistinguishable from other typical Summer days in 2002.*
- *All of this emergency capacity and demand reduction was treated as essentially \$0 cost must run supply in the dispatch software price setting process.*

Recognition of “Bad” Scarcity Pricing

- *In his report on the NYISO market on October 15, 2002, market advisor David Patton concluded that:*
 - *“the current pricing rules and operating procedures have hindered the market from setting efficient prices during shortage conditions. This problem is common to all of the operating wholesale energy markets.”¹*

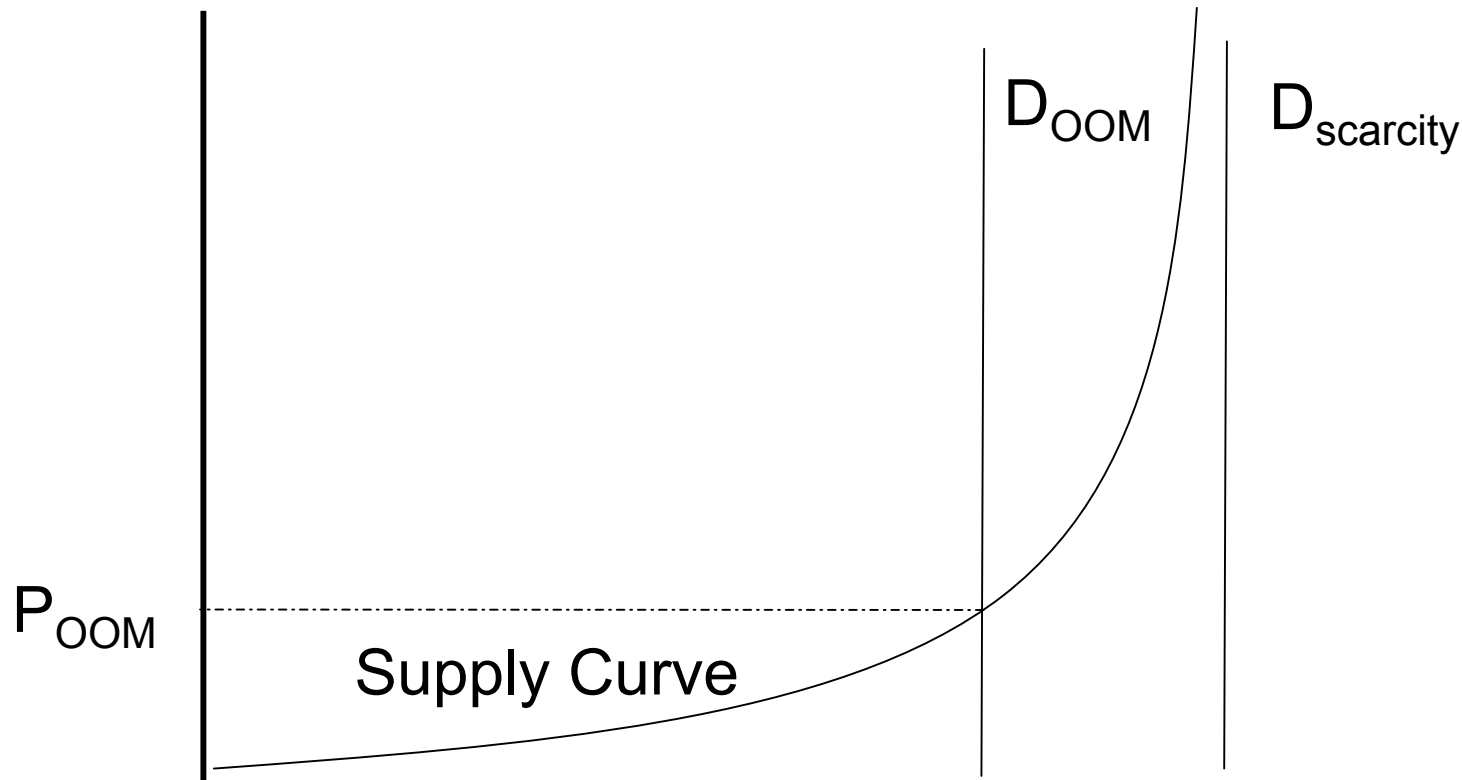
¹ - Summer 2002 Review of the New York Electricity Markets, at p. 3 (October 15, 2002).

What ISO's Do When Scarcity Occurs

- *The following are actions the ISOs may and do take when facing a scarcity condition or possible scarcity condition:*
 - *Call on emergency imports,*
 - *Cancel scheduled exports,*
 - *Call interruptible load contracts,*
 - *Take energy from reserves,*
 - *Overload transmission facilities,*
 - *Let frequency or voltage drop,*
 - *Curtail some “firm” demands*
 - *Overcommit resources, such as ISO-NE replacement reserves or NYISO SREs.*
 - *Have high cost units called by local TO running out of merit for local reliability, even if these units would set prices if not flagged OOM.*
- *Many of the actions are reductions in demand – in fact, contrary to conventional wisdom, demand is and has been very elastic during scarcity conditions.*
- *All of these actions have costs – most of these costs are very high.*

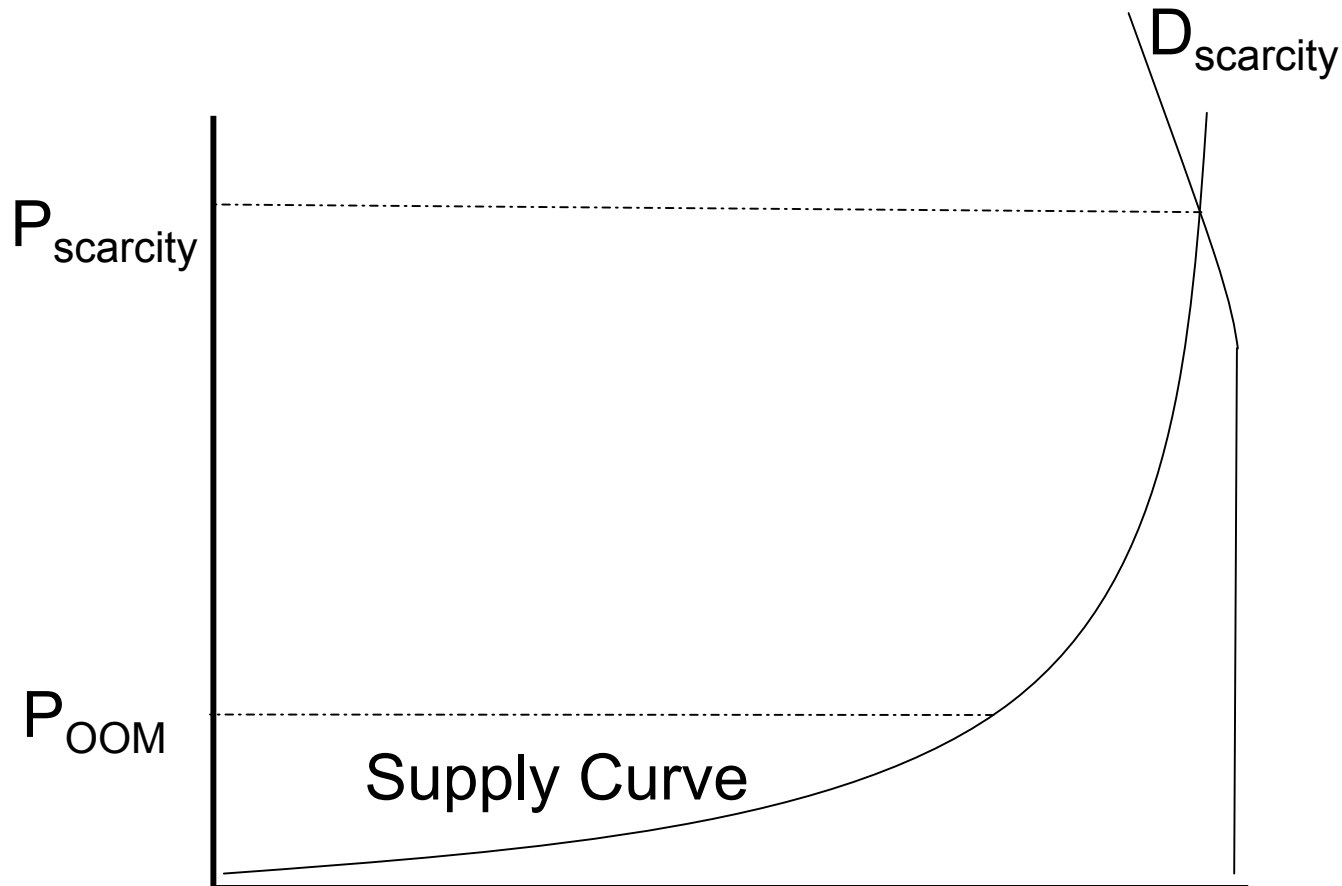
Bad Scarcity Pricing

- *Bad scarcity pricing means that all the Out-of-Merit actions taken by the ISO are treated as \$0 cost in setting price.*



Good Scarcity Pricing

- *In a rational scarcity pricing process, the ISO would develop estimates of the costs of the OOM actions it may take, and then put those actions into its dispatch, market-clearing, and pricing engines, much like any other supply or demand-reduction option.*



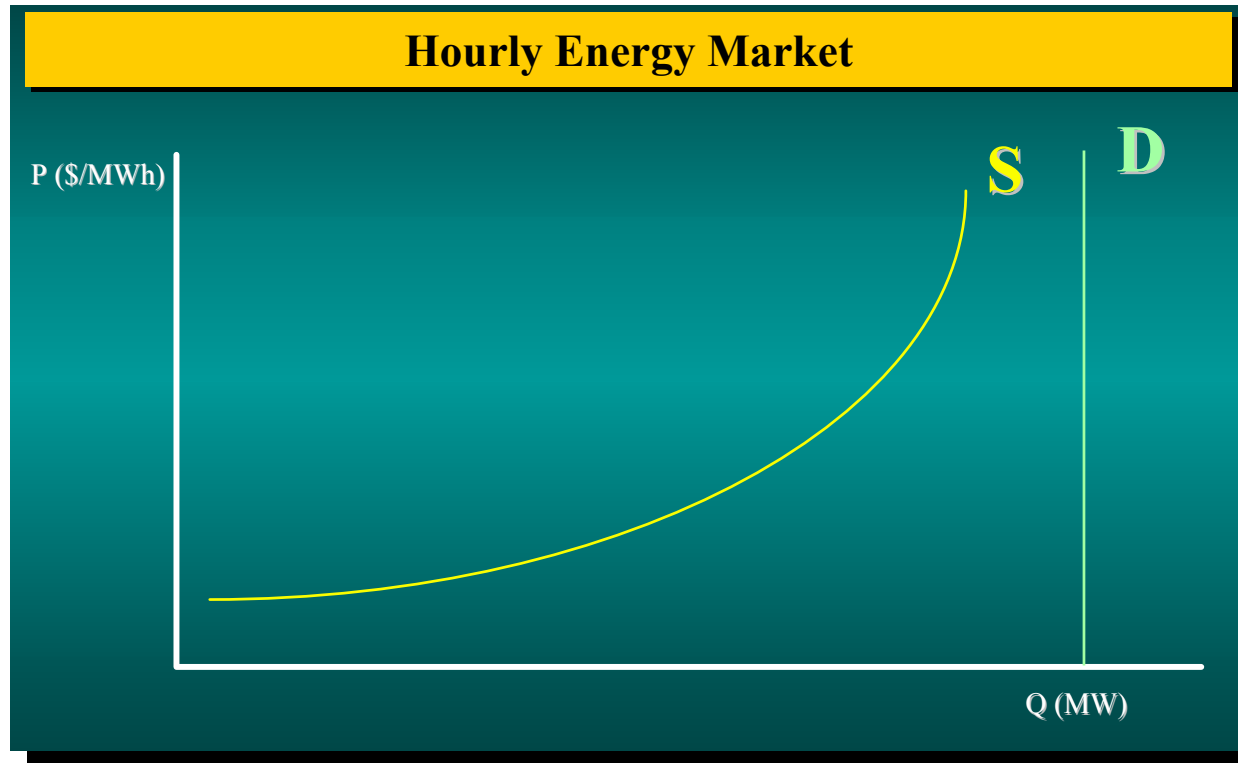
Market Performance Conclusions

- *Conclusion 1: Even in Summer with 1 in 15 year heat wave (8/01), spot energy prices were not sufficient to support entry without a capacity payment.*
- *Conclusion 2: As currently designed, capacity markets in the Northeast do not provide sufficient revenue to new entrants even though new entry is or has been needed.*
- *Conclusion 3: Each ISO's market rules suppress prices below competitive levels during scarcity, and each ISO has other mechanisms in place to suppress prices during normal hours.*
- *Conclusion 4: No market power (materiality and sustainability) in the Northeast electricity markets.*
 - *A market needing new entry which has prices below the cost of entry is devoid of market power by definition.*
 - *Emphasis of regulators and market monitors on bidding behavior, aggressive mitigation even in broader (non-load pocket) wholesale markets, and "gaming" of capacity markets is not supported by the data on market performance from the Northeast. This emphasis may actually be reducing market efficiency.*

Why Capacity Matters

Market Clearance

The System Operator's Nightmare



- *The reliability of the electricity system requires that load and generation balance in real time . . . not only on an “average” day, but also on the peak day.*

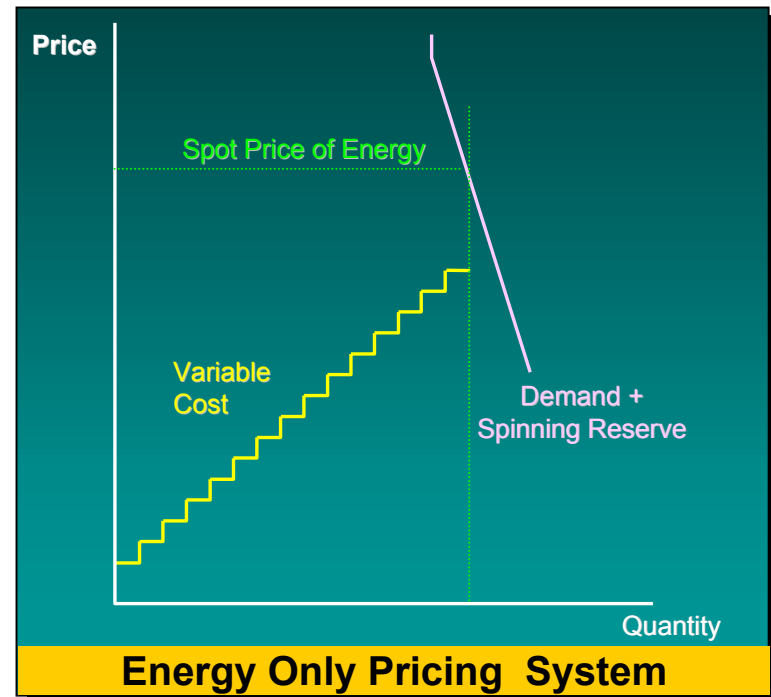
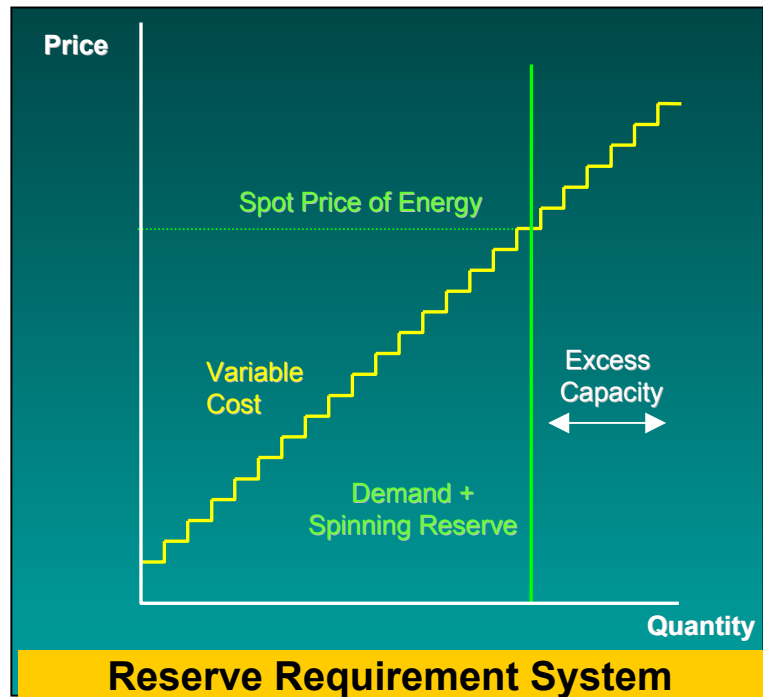
Will “Restructuring” Endanger Adequate Reserves?

- *In the regulated market, installed reserves are maintained through the “regulatory bargain.”*
 - *The monopoly utility agrees to operate and maintain the electricity system in exchange for a guaranteed rate of return*
 - *The utility satisfies reliability standards regarding capacity through a regulated resource planning process.¹*
- *Under competition, all units needed for reliability must be compensated enough in the long run to recover their fixed costs and avoid closing.*

¹ For instance, the Northeast Power Coordinating Council (NPCC) sets a reliability standard of one in ten years of loss of load probability: “Resources will be planned in such a manner that after due allowances for scheduled maintenance, forced and partial outages, interconnections with neighboring areas, and available operating procedures, the probability of disconnecting non-interruptible customers due to a resource deficiency, on the average, will be no more than once in ten years.”

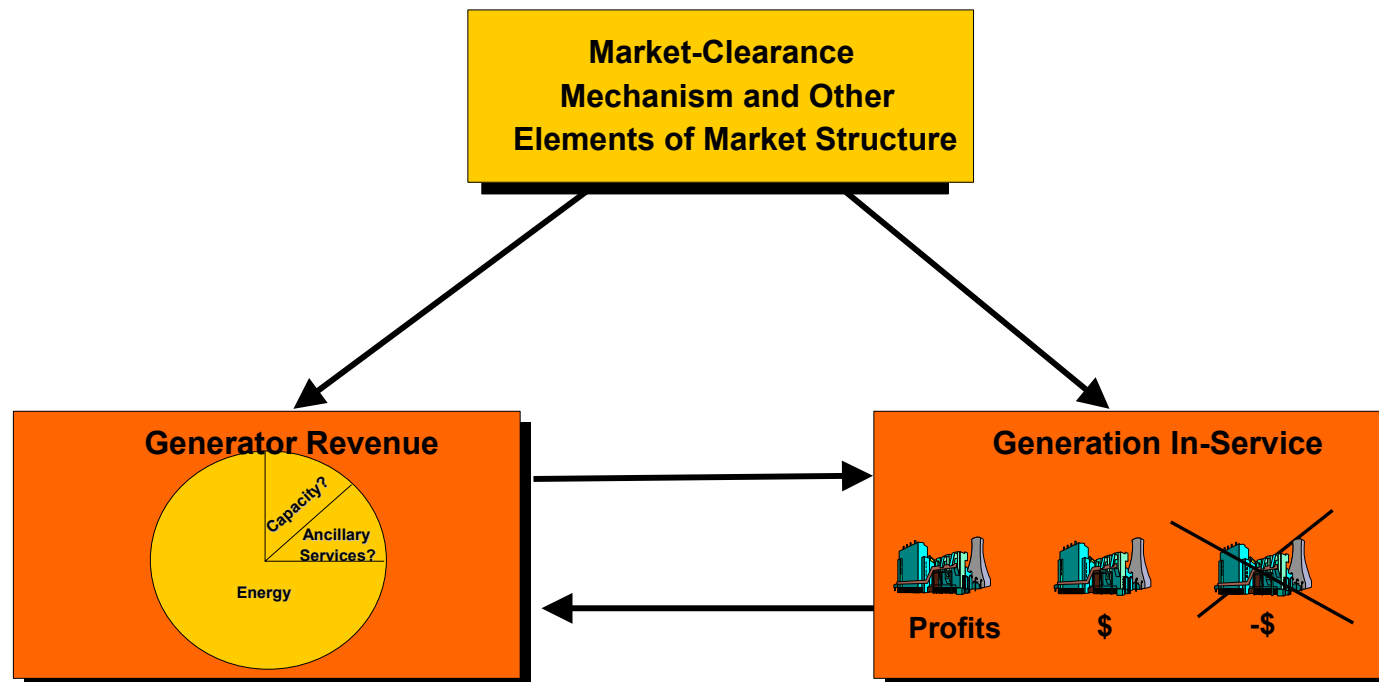
Policy Options

- There are two alternatives to ensure market clearance under competition:
 - Maintaining sufficient “excess” generating capacity that the market clears, even if the demand curve is vertical. (Reserve requirements or hourly capacity subsidy)
 - Maintaining sufficient price-responsive demand that the market clears, even if the supply curve is vertical.



The Choice of Market-Clearance Mechanism Will Affect Market Outcomes

- *The choice of a market-clearance mechanism will affect forecasts of the level of electricity market clearing prices, the payments that generators receive for providing energy and capacity and, therefore, the profitability of existing and new generation.*
- *The choice of market clearance mechanism is linked to other choices regarding market structure – such as price caps, market mitigation and operating reserve pricing.*



FERC Doesn't Like The Options Is There a "Third Way"

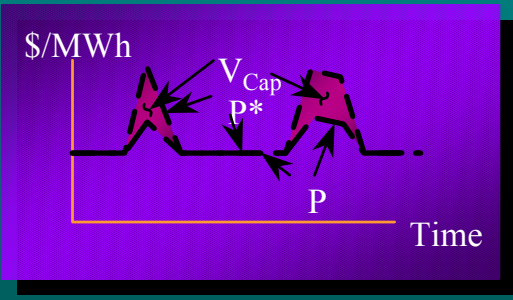
- *Concerns with Energy-Only Pricing System*
 - *Price spikes, price spikes, price spikes.*
 - Could be market power*
 - Could be real scarcity with efficient "competitive price" above \$1000/MWh bid cap.*
 - Regardless, FERC recognizes that "spot market prices that are subject to mitigation measures may not produce and adequate level of infrastructure investment."*
- *Concerns with Reserve Requirements System*
 - *Existing ICAP in PJM, ISO-NE, NYISO have not worked well (a new joint proposal from the three pools is being developed)*
 - *These pools had "voluntary" tight power pools, with strong roles for the ISO in administering the program. FERC is reluctant to impose this on regions without history of tightly coordinated reserve sharing.*
- *FERC has been seeking a means of reconciling these concerns:*
 - *The Reserve Adequacy Requirement in the SMD NOPR*
 - *Forward Reserve Contracts – Staff Discussion Paper*

Policy Options for Assuring Adequate Capacity

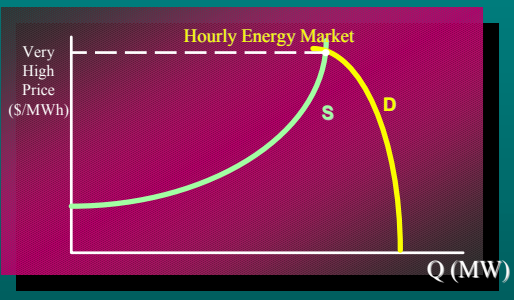
← Reserve Requirements Based Energy-Only Based →



Capacity Obligation



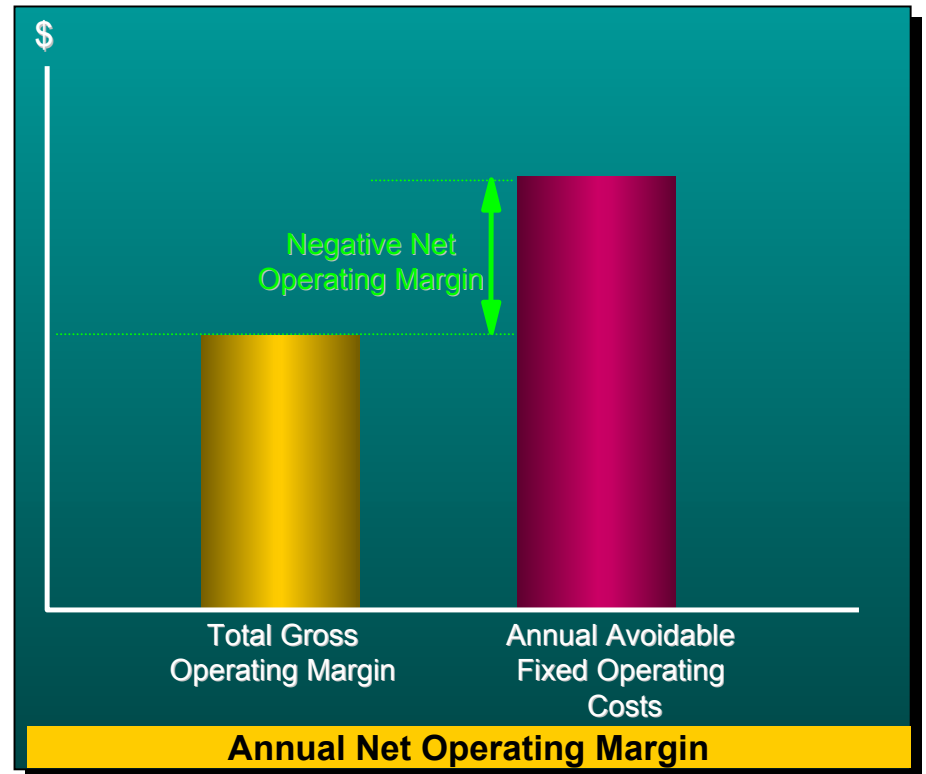
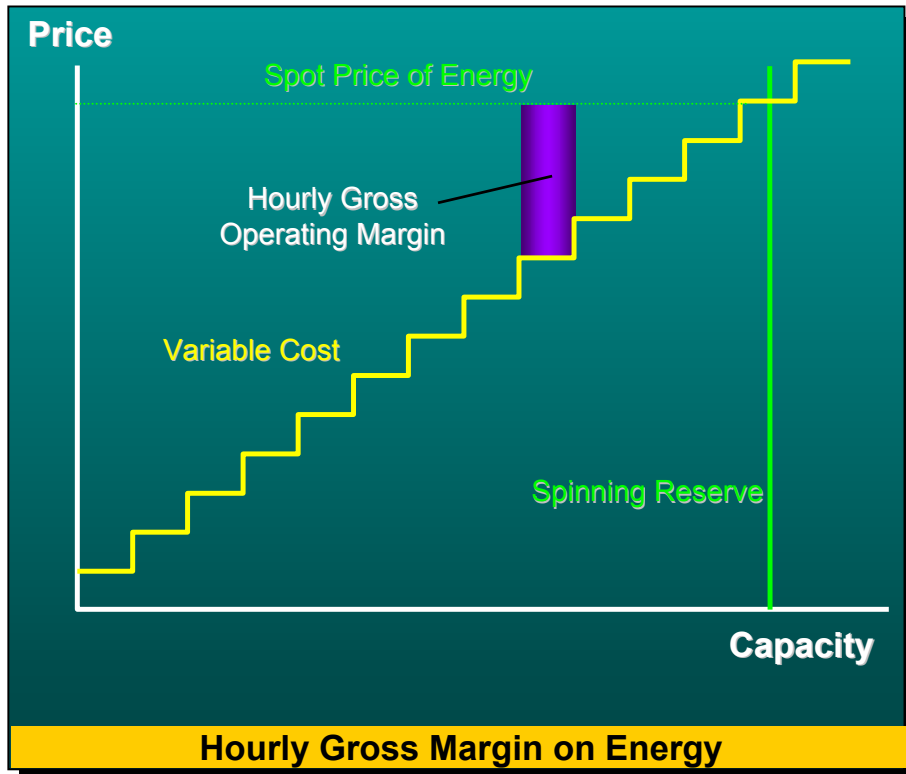
Explicit Capacity Adder



Market Clears with Dispatchable Demand

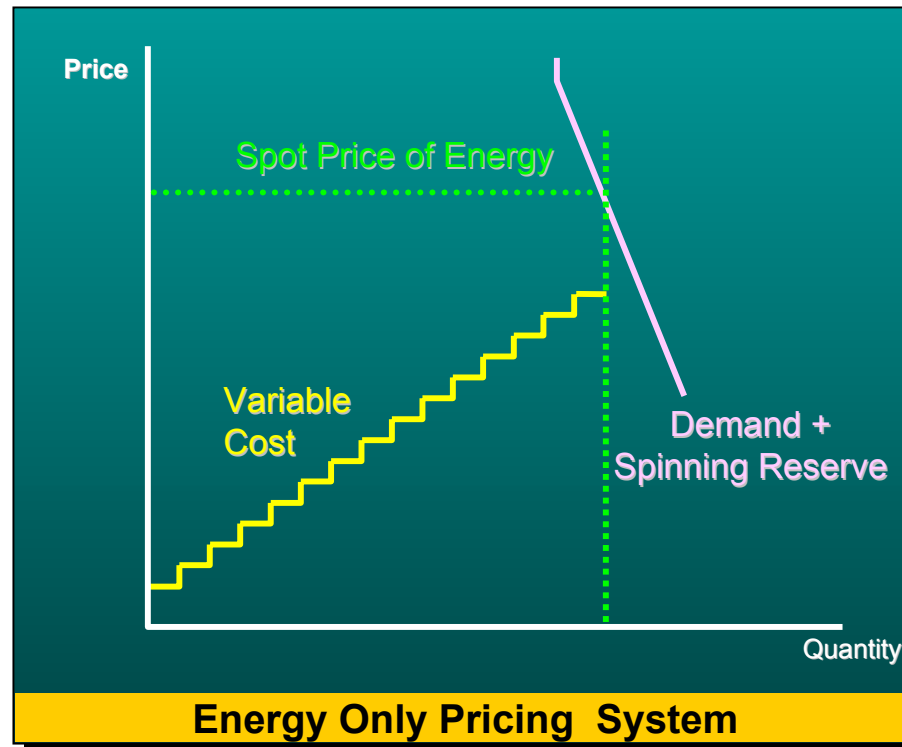
Ensuring Adequate Capacity Under Competition

- Generators will only remain in service and contributing to reliability if their market revenues cover their variable and avoidable fixed operating costs.



Energy-Only Pricing

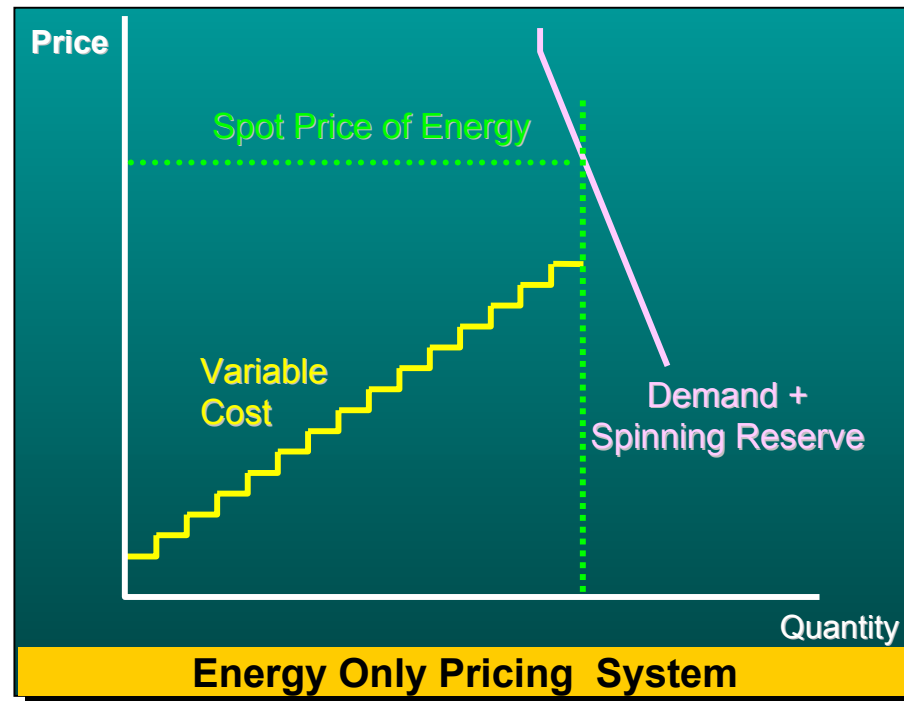
- *Proponents argue that market-based energy-only pricing systems would lead to economically efficient capacity levels in the long run if prices are allowed to rise to levels that clear the market.*



- *Ultimately, customers would rather curtail their use of power voluntarily than pay exorbitant energy rates.*

Market-Determined Reliability

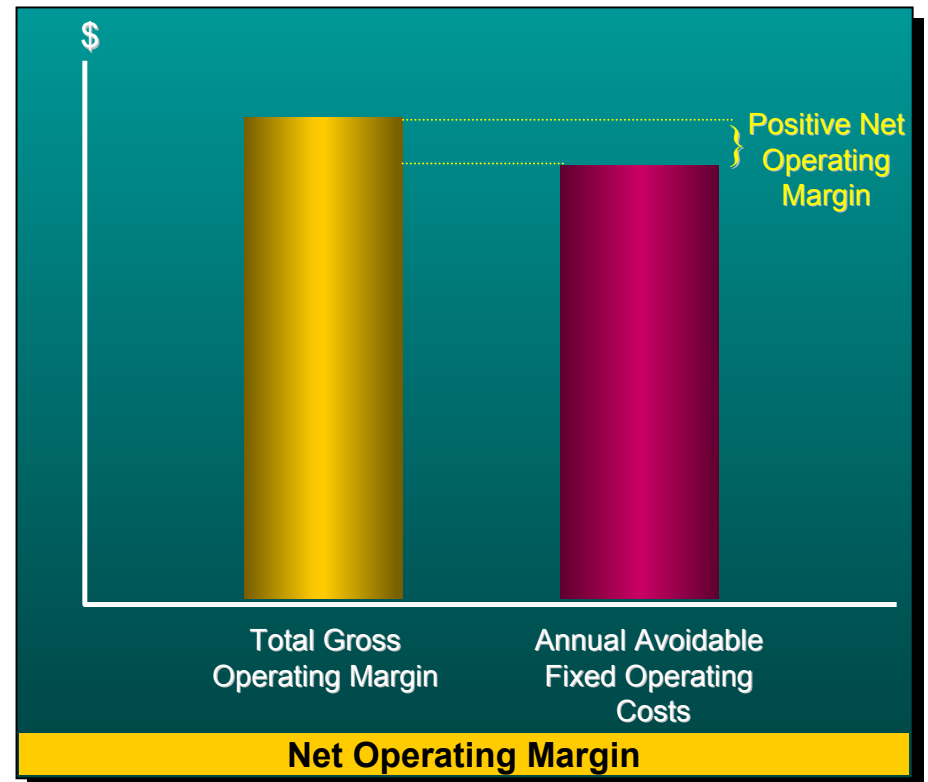
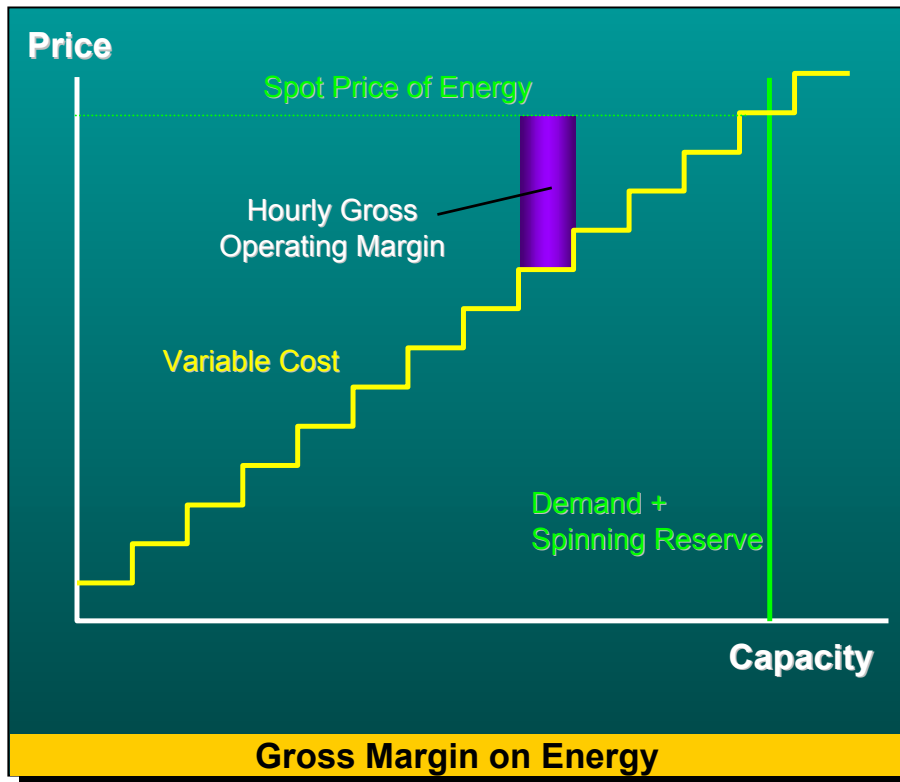
- *The market clears through price-responsive customer demand and operating reserves, without the need for administratively determined installed reserve requirements or a separate capacity payment. Operating reserve margins would be maintained, with flexible load adjusting to high prices.*



- *Long-term, installed capacity decisions would be left to market incentives.*

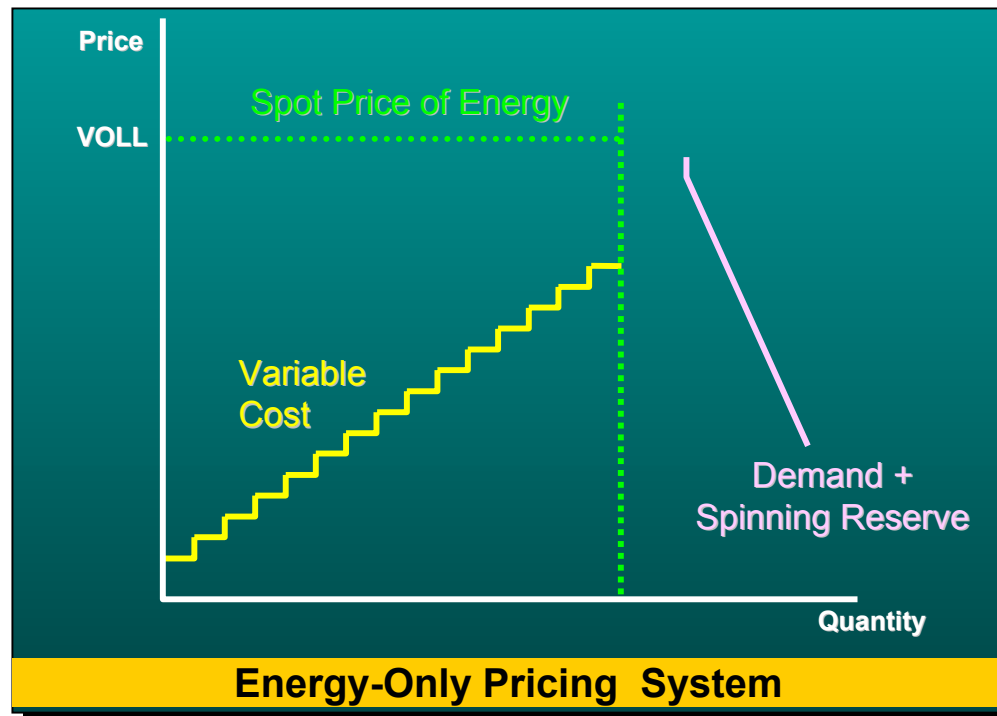
Energy-Only Pricing: How Generators Stay Open

- Generators would only remain in service only if their gross operating margins exceeded their avoidable fixed costs. If not, they would be either mothballed or retired.



Energy Price if the Market Does Not Clear

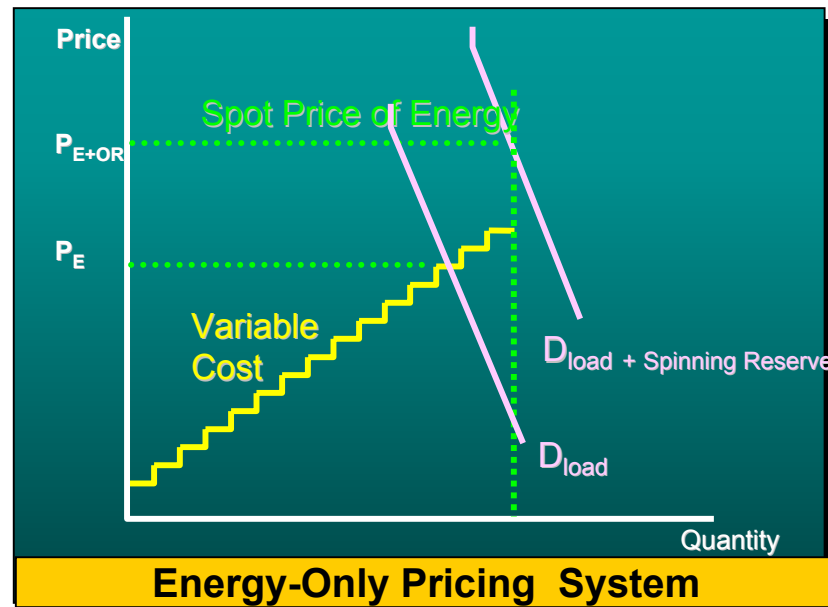
- A penalty -- the value of lost load -- (VOLL) – can be used to set the market price if the market does not clear under energy-only pricing.



- The VOLL is set high enough to reflect the cost to society of involuntary curtailments. LSEs have the incentive to invest in capacity contracts to avoid having to pay the VOLL amount.

Efficient Pricing of Operating Reserves Can Help Provide Additional Revenue For Generator Fixed Costs

- “Operating reserves” refers to spinning reserve or other operating reserves that are needed by the ISO on a daily basis to operate the electricity grid safely and reliably.⁴ The market for energy plus operating reserves will be tight in hours when the market for energy clears without much problem.

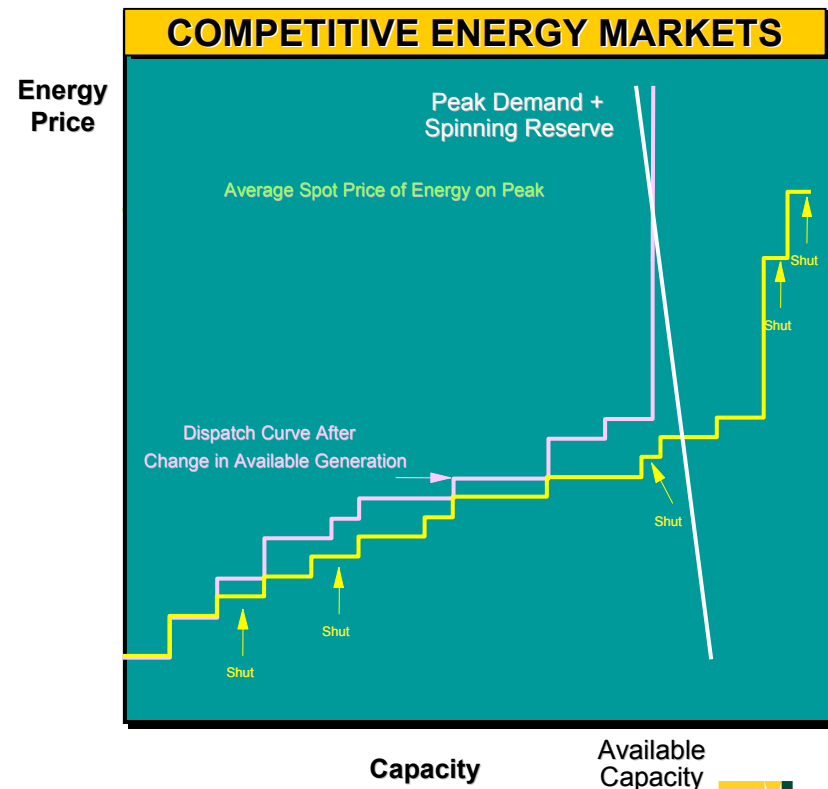
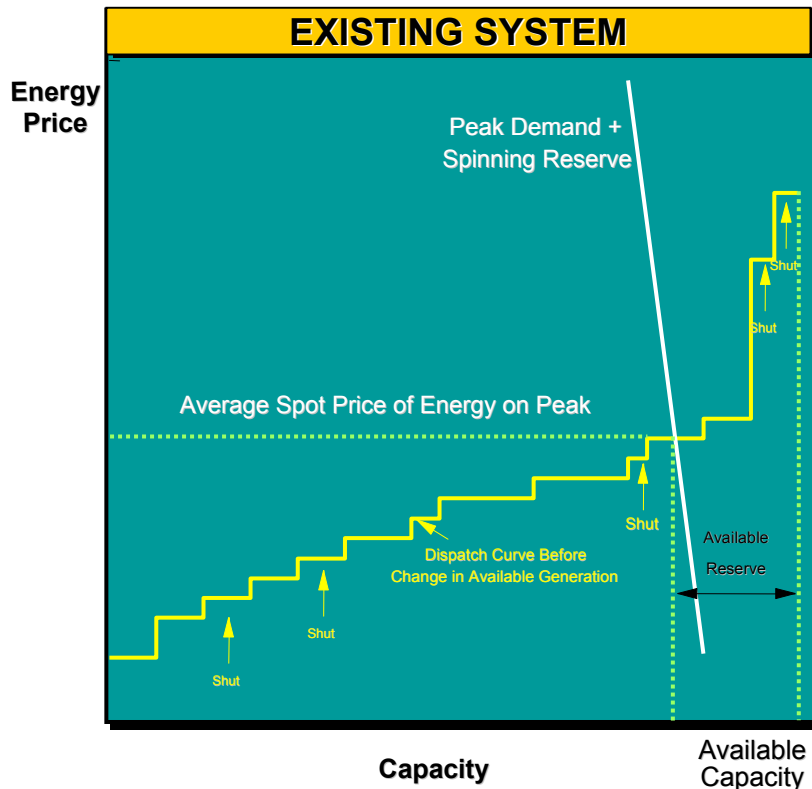


- Market rules for pricing energy and reserves when operating reserves are tight matter a great deal. It is essential in an energy-only system that prices be allowed to rise during a generation shortage, even if the shortage is of reserves and not energy.
- One of the many failures in the California ISO market design was failing to get energy/reserve pricing correct.

⁴ Operating reserve should not be confused with installed reserve which is the topic of this presentation intended to address long-term reliability.

Energy-Only Market Price

- Under energy-only pricing, the location and shape of the dispatch curve would differ from the present system due to differences in the available generation. Generation would exit the market if its avoidable fixed operating costs exceeded its margin on energy and ancillary services sales.



Energy-Only Market Equilibrium

- *Characteristics of energy-only pricing:*
 - *On-peak energy prices may be quite high*
 - *Less capacity available than under a system with reserve requirements*
 - *Peak energy consumption would be lower due to demand-side response*
- *Energy-only systems currently exist -- and clear the market -- in both Australia's and New Zealand's competitive electricity markets.*
 - *Maximum prices in Australia have hit the VoLL level, currently set at \$AUD5,000 and being increased to \$AUD10,000 in 2002 (approximately \$2,500 and \$5,000 USD respectively)*
- *Northeast markets as designed are not consistent with an energy only pricing system:*
 - *Extensive use of price caps, cost-capping and market mitigation*
 - *No separate/efficient pricing of operating reserves in PJM/NEPOOL*
 - *Uplift payments to slow-starting, inflexible marginal generation.*
- *A fundamental principal of energy-only pricing systems is that prices must be allowed to rise high enough to clear the market.*

Barriers to Implementation of Energy-Only Pricing

- *Assuming the political barriers to high spot prices could be solved, there are three practical barriers to implementing the energy-only system:*
 - *Current inadequate levels of dispatchable demand*
 - *Lack of real-time metering*
 - *Must-run generation inside load pockets*

Barriers to an Energy-Only System Adequate Dispatchable Demand

- *The development of customer demand-side response is expected to be one of the dynamic benefits of moving to a competitive electricity market.*
 - *In the long run, the market institutions and customer incentives will exist to sustain a large amount of price-responsive load under energy-only pricing.*
 - *At present, however, in many control areas relatively little load is metered for time-of-use pricing, even less load has the ability to track real-time prices, and much load has a limited ability to respond to high prices either day ahead or in real time.*
 - *Moreover, because an installed reserve system keeps energy prices low, it tends to discourage the very customer investments that will be needed to develop additional price-responsive load.*
- *Inadequate levels of dispatchable demand could result in blackouts in the absence of required reserves.*

Barriers to an Energy-Only System

Inadequate Real-Time Metering

- *For an adequate demand-side response, the customer must see and respond to the high real-time price of electricity when capacity is scarce.*
 - *LDC must be able to measure electricity usage in real time, or*
 - *LDC bids price-responsive demand, even if customers do not have access to real-time prices, and curtails less essential loads when opportunity costs are high.*

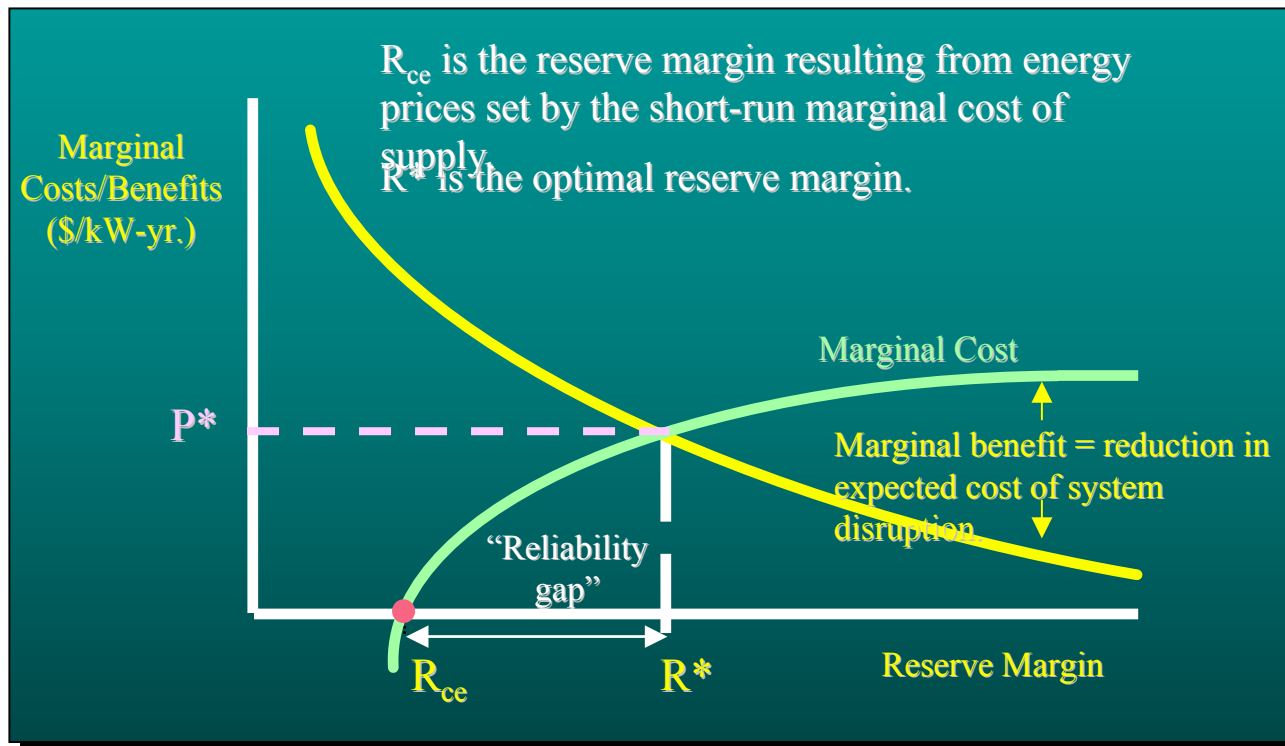
Customers would need to agree to some level of interruption

LDC circuits may need to be re-wired to segregate less essential loads, which may be expensive (this is a major flaw in the RAR)

The Reserve Requirement System

Why Set a Reserve Requirement?

- Capacity as a positive externality
- Capacity and demand response resources provide reliability benefits all users of the grid.
- Energy prices alone do not internalize the social benefit of capacity in terms of its contribution to reliability, and yield sub-optimal reserves.



Source: Jaffe and Felder, *The Electricity Journal*, Dec. 1996.

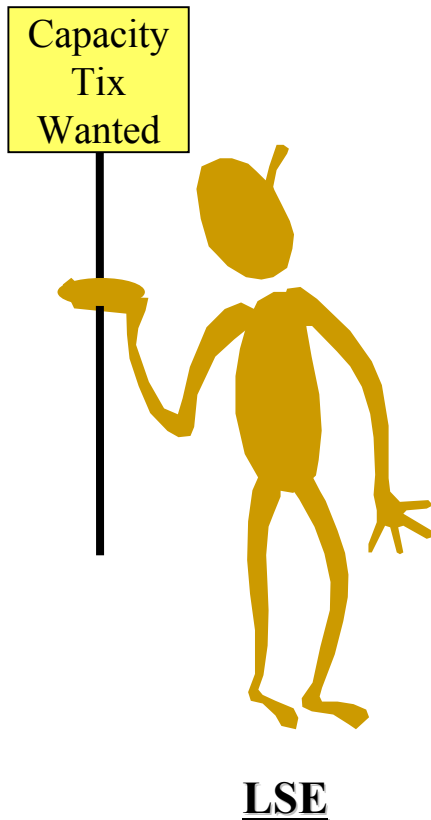
The Reserve Requirement System

Why Set a Reserve Requirement?

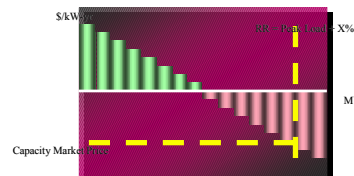
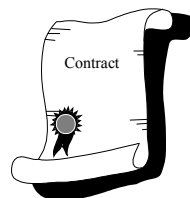
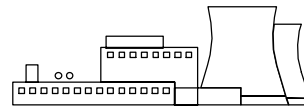
- *Established reserve requirement mimics traditional capacity planning process of regulated industry model.*
- *Capacity as a “positive externality” – Is this correct economics?*
 - *Only assuming a market failure of insufficient real-time metering and demand response mechanisms.*
 - *If customers could voluntarily curtail the market would always clear if prices were allowed to rise sufficiently.*
- *An alternative justification – high enough energy prices are politically infeasible and installed reserve requirements are a “second best” solution necessary to ensure market clearance.*

Reserve Requirement System: How It Works

- A reserve requirement is imposed symmetrically on all LSEs, who need to demonstrate adequate reserves. To meet their requirement, LSEs must enter into explicit or implicit contracts with generators to avoid **large deficiency penalties** and enable the generators to recover their avoidable cost. Capacity thus takes a value in and of itself.



Capacity Ticket Options

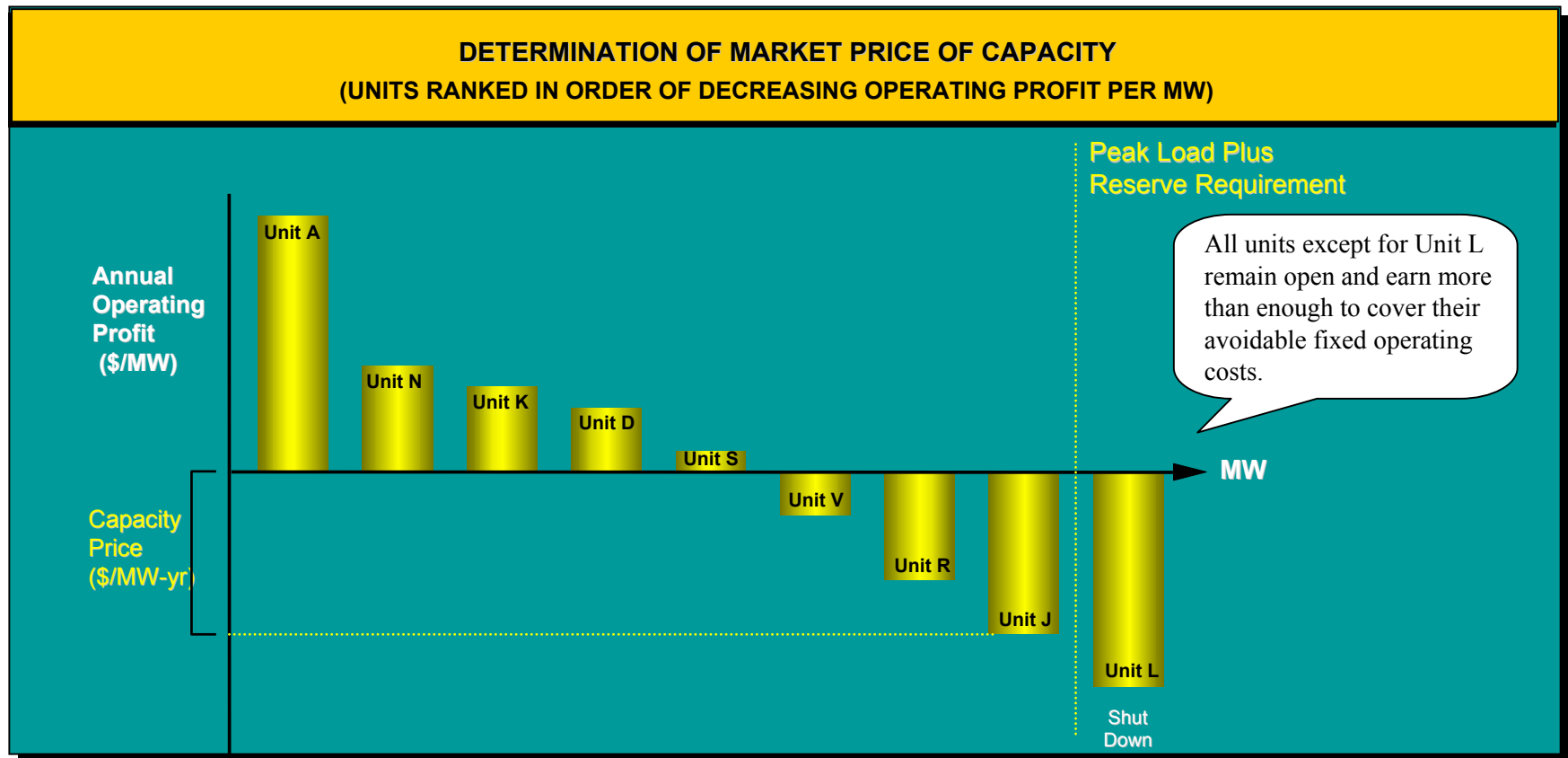


**Purchase from Pool at
Auction Clearing Price?**

Each generator would require a payment of at least the difference between annual avoidable operating cost and its annual revenues for energy and ancillary services.

Reserve Requirement Model Market Price of Capacity

- *Competition among capacity owners would cause the market-clearing payment to approximate the smallest per-MW payment that would induce just enough generation to remain available to meet the reserve requirement. All generating capacity contributing to the pool installed reserve would be paid the market-clearing price of capacity.*



What Creates the Market for Capacity?

- *Capacity markets are created by an explicit public policy choice to establish (and enforce) an installed reserve reliability requirement.*
 - *Whether ISO/RTO administers a capacity “auction” process and posts “prices” is irrelevant.*
 - *Penalties for deficiency are essential to enforcement. Why make a capacity payment if the penalty for not making the payment is less than the payment?*

Devilish Details

Time Frame and Retail Competition

- *Time Frame*

- *If capacity payments are necessary to provide entry signals, the appropriate time horizon may be 3- to 5- years*
- *Northeast ISO capacity markets were explicitly designed with shortened capacity periods over which the requirement is allocated to LSEs. This was deemed necessary to accommodate retail competition with customer relationships changing month to month.*
- *But daily and monthly capacity markets may not provide adequate entry signals and have proven to be volatile.*

- *Retail Competition*

- *On whom does one impose a reserve requirement 3-5 years from now?*
- *Who is responsible for ensuring that the capacity gets built?*

Northeast Capacity Markets Have Worked Poorly

- *Daily or monthly market is too short-term. Capacity cannot be added in response to price signals.*
 - *Short-term capacity accounting was deemed necessary to accommodate retail competition.*
 - *Because of this time frame, capacity prices are either at the cap or zero, with little middle ground.*
- *Tight time-frame can lead to gaming – with allegations of markets being cornered.*
- *Market design for ICAP in PJM has the deficiency payment/cap well below the cost of entry.*
- *Inappropriate mixing of long-term and short-term reserve products with implementation of PJM West.*
- *Some claim that the unpredictability of ICAP prices is a barrier to retail competition*
- *Others claim that the unpredictability of ICAP prices and the market rules which suppresses ICAP prices below the cost of entry will hinder necessary new entry in the long run.*

Northeast ISOs

Joint Capacity Adequacy Group (JCAG)

- *Interregional effort between PJM, NYISO and ISO-NE to standardize regional reliability market designs.*
- *Group met through 2002 and developed proposal*
 - *FERC consulted, and ISO SMD filings addressed JCAG process*
 - *Target is to refine proposal and have joint FERC filing in 2003*
- *Objectives:*
 - *Assure longer term system reliability*
 - *Ensure an open and competitive market*
 - *Foster competitive bilateral transactions and retail access*
 - *Identify all resource adequacy sources and ensure set performance standards*
 - *Balance needs of capacity resources and load*
 - *Administer a market that sends the correct price and new entry signals*
 - *Eliminates seams issues*
 - *Resource Adequacy should be a marketable product*
 - *The role of ISO/ITP should be limited to market administration*

The JCAG Solution: Centralized ICAP Procurement with 2-5 Year Lead Time

- *ISOs would hold centralized auctions for capacity with sufficient lead time for a generator to be built based on the outcome of the auction (2-5 years).*
- *Cost of capacity procured by the ISO is charged to end users through a non-bypassable fee – just like transmission.*
 - *Retail price of capacity very transparent.*
 - *No disadvantage to retail suppliers who do a poor job of purchasing capacity.*
- *Winning bidders (Gencos / marketers / bilateral / utility self-supply) have obligation to deliver capacity – very high penalties for non-performance create incentives to ensure that capacity obligations are met.*
- *Secondary market facilitated by the ISO to allow for capacity “reconfiguration” (just like financial transmission rights).*

Centralized Capacity Procurement Efficient Cost Recovery

- *Policy-makers would have choices regarding how to recover the fixed capacity payments from load:*
 - *A fixed annual fee which spreads the charge over time, or*
 - *An hourly charge allocated only to hours when the loss of load probability is high.*

$$\begin{array}{c} \text{Hourly Reliability} \\ \text{Charge for LSE}_A \end{array} = \frac{\text{LOLP}_h}{\sum_{N=1}^{876} \text{LOLP}_N} * \frac{\text{Load}_{\text{LSE}_A h}}{\text{Load}_{\text{Pool } h}} * \begin{array}{c} \text{Annual Capacity} \\ \text{Payments to} \\ \text{Generators} \end{array}$$

- *The latter approach would have many of the benefits of high prices:*
 - *Incentives for creation of demand response*
 - *Incentives for generator availability when the generators are needed*
ISO could get out of the business of capacity testing and monitoring forced outage rates; unavailable generators simply lose out on the capacity payment if they are unavailable
 - *Could be a transition mechanism to energy-only pricing while demand response and metering technical issues are solved.*
- *The latter approach would have all the political disadvantages of high prices.*
 - *Policy-makers may choose the fixed annual fee approach if they want the subsidy to be less transparent.*

The SMD NOPR's RAR

The Reserve Adequacy Requirement

- *Establishes Regional State Advisory Committee*
 - *Sets planning horizon (up to 5 years; sufficient lead time for entry)*
 - *Sets reserve requirement (minimum 12%) to be allocated to LSEs*
- *LSEs*
 - *Contract for sufficient capacity in advance*
 - *Submit plans to ITP*
- *ITP*
 - *Reviews and audits LSE plans*
 - *Takes names/quantities for LSEs that are short (i.e. 3 years in advance)*
- *Enforcement / penalties*
 - *Only spot market buyers/LSEs that were listed by ITP previously (i.e. 3 years before)*
 - *Only when market is short of operating reserve*
 - *Graduated penalty amounts imposed when market is short of operating reserves.*
 - I.e. \$500 when operating reserves are just short; \$600 when 1% short; \$700/MW when 2% short, etc.*
 - *LSE's that did not satisfy the requirement are curtailed first, their state regulators notified and subject to \$1000/MWh penalty if not sufficiently curtailed.*
- *Load shifting due to retail access / competition not addressed*

The Reserve Adequacy Requirement Positives

- *Recognizes the need for adequacy*
 - *Sees capacity as a positive externality. Sees investment in capacity or demand response as providing reliability benefits to all users of the system*
 - *This may be true, but only assuming a market failure of insufficient real-time metering and demand response mechanisms. If customers could voluntarily curtail the market would always clear if prices were allowed to rise sufficiently.*
- *Recognizes that mitigated energy prices are insufficient for efficient entry signals*
- *Recognizes that penalties and enforcement provisions must be high enough to make compliance a better option than non-compliance (but falls short of accomplishing this)*
- *Recognizes that requirement:*
 - *Must be forward-looking and have sufficient lead time to allow for capacity planning.*
 - *Location is important*
 - *Deliverability is important*
- *Concept of capacity penalties tied to spot market deficiency in operating reserves, similar to UK capacity subsidy system if applied to all spot market buyers, not merely those that were listed 3 years ago*
- *A creative approach and a new idea*

The Reserve Adequacy Requirement Bottom Line

- *FERC Commissioner Pat Wood, Nov. 14 2002:*
 - *The NOPR didn't get this right.*
- *FERC seems to have caught onto the major flaws:*
 - *Not compatible with retail competition.*
 - No way to forecast LSE loads so far in advance*
 - A barrier for smaller new entrants*
 - *LSEs can bypass penalties by bypassing spot market with day-ahead bilateral purchases*
 - *LSE's "plans" may be adequate 3 years prior, but it may not implement them. No monitoring of implementation.*
 - *LDC circuits not wired for targeted curtailments*
 - *RAR's short-term penalties are not sufficient to assure adequacy. Failure to comply costs less than compliance.*

The RAR

There is no “third way.”

- *To have adequacy, prices need to be high enough to support all units needed for reliability in the long run.*
- *Either:*
 - *High-enough energy prices*

Policy bias must be to avoid suppression of market prices via too-aggressive mitigation even if this means some instances of transitory market power go unmitigated

SMD must explicitly demand implementation of “good” scarcity pricing (and should do so regardless)
 - *Capacity prices to make up for insufficient energy prices resulting from an effective capacity requirement defined and enforced by a strong ITP.*

The Northeast ISOs are finalizing a proposal that will work through the Joint Capacity Adequacy Working Group (JCAG)

Forward Reserve Contracts

Are Forward Reserve Contracts a Better Alternative to ICAP?

- *The basic idea:*
 - *If prices are set to short-run marginal cost, peaking units can not recover their cost of capital*
 - *Solution: Target subsidies to peakers through special contracts*
 - *Added benefit: Units that do not need the subsidy (baseload units) don't get it – Capacity on the Cheap!*
- *The idea was spelled out in a FERC Staff discussion paper in late 2001*
- *Forward reserve contracts as conceptualized in the FERC staff paper are likely to be both inefficient and unworkable.*

Forward Reserve Contracts are Inefficient Because They Distort Resource Allocation

- *Targeted capacity payments will create an inefficient resource allocation mix and inflate the cost of capacity for consumers – the opposite of the intended effect.*
- *In terms of market clearance, there is and can be **NO BRIGHT LINE** between the contribution of a “reserve” unit and a baseload unit -- every available MW contributes equally to market clearance on a high load day.*
 - *By targeting capacity payments only to “peakers,” peakers will be the type of capacity constructed even when competitive forces dictate that some other form of capacity is more appropriate.*
 - *Units that do not qualify for the targeted payment may close, even if they would require a lesser payment than the peaking units that receive the subsidy. The net effect may be a reduction in installed reserves and reliability.*

Forward Reserve Contracts are Inefficient Because They Distort Resource Allocation

- Consider the energy margin and capacity revenue needs of a new CC vs. a new CT optimally dispatched against 2001 NEPOOL energy prices:

| NEPOOL New Entrants and Capacity Payment Needs | | | |
|--|-------------------------------|---------------------------------------|---------------------------------------|
| | 2001 Energy Margin (\$/kw-yr) | Annual Revenue Requirement (\$/kw-yr) | Capacity Payment Shortfall (\$/kw-yr) |
| New CC | 71 | 95 | 24 |
| New CT | 30 | 65 | 35 |

- By targeting the capacity payment only to the “reserve” unit, the less efficient unit is built. The owner of the CT will not convert the unit to a CC even though society would be better off with the cheaper baseload unit built.

Forward Reserve Contracts are Inefficient Because They Distort Resource Allocation

- *Now consider a marginal existing steam unit that also does not qualify for the forward reserve payment. In this case, we exclude return on capital from the revenue requirement because the investment is sunk, and only consider avoidable fixed costs (also referred to as going-forward costs).*

| NEPOOL New Entrants and Capacity Payment Needs -- Now Consider the Existing Unit | | | |
|---|----------------------------------|--|---|
| | 2001 Energy Margin (\$/kw-yr) | Annual Revenue Requirement (\$/kw-yr) | Capacity Payment Shortfall (\$/kw- yr) |
| New CC | 71 | 95 | 24 |
| New CT | 30 | 65 | 35 |
| Existing ST/G | 37 | 45 | 8 |

- *The existing steam unit will close even though it needs a smaller capacity payment than the new CT, again distorting the resource allocation mix and raising both energy and capacity prices to consumers.*
- *Further, closing the steam unit while building a new peaker results in no net increase in reserves, and potentially a decrease.*

Forward Reserve Contracts are Unworkable Because They Require Extensive Rulemaking to Enforce the Intended Price Discrimination

- *How does the ISO target reserve payments to ensure the right capacity mix? Would the ISO now have to engage itself in integrated resource planning process to “pick” the winner of the targeted capacity payment?*
- *How does the ISO decide who gets to apply for the targeted payment?*
- *Does the ISO limit LSEs from self-providing reserves – would a market participant that owns 125% of its peak load in non-“reserve”-units still have to pay toward the ISO/RTO’s cost of purchasing targeted reserves? If not, non-reserve-designated units can obtain the capacity payment by contracting with an LSE bilaterally.*

Forward Reserve Contracts Is Price Discrimination Appropriate?

- *Utility ratepayers owning existing assets that are not reserve units would see the value of the asset arbitrarily reduced.*
- *Owners of recently built or purchased units that assumed ROE based a competitive market with one market clearing price for all units (econ 101) would see the value of their assets taken away.*
- *If capacity subsidies are only paid to new entrants, over time everyone will be a new entrant and is being paid approximately its embedded cost. Sounds like regulation rather than competition, and all that is accomplished is that the capacity payment was avoided for existing assets that are “sunk” today – I.e. regulators simply seized property because it was there.*
- *Further, what about units that would close but for ICAP payments – do you let them go away and then come back as “new” units?*
- *ICAP markets avoid each of these thorny issues because the market will decide the resource allocation mix, and all units contributing to reserves get the same payment.*
- *During times of excess capacity, ICAP prices will not be sufficient to provide return on equity to all units in the market. This is appropriate and a better way to ensure adequate reserves than the quasi-regulatory process which is liable to lock in embedded cost payments to generators which the market may ultimately deem unnecessary.*