Scarcity Pricing in Northeast ISOs:
An Assessment of Market Performance

Abram W. Klein
Edison Mission Marketing & Trading
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Discussion Topics

• Introduction

• Market performance to date – What can we conclude?
  - Compensation for new entrants
  - Spot prices during scarcity

• Mechanisms of “bad” scarcity pricing

• Policy Implications for:
  - SMD/ISO/ITP Pricing Rules
  - Market mitigation
  - Installed reserve/adequacy market design
Introduction: The Purpose of Spot Electricity Markets
Two Functions of Spot Markets

A spot market in electricity has two principle functions:

- **Maintain Efficient Short-Term Operations and Dispatch** – Least-cost and reliable dispatch to meet load given available resources in the hour/day; efficient usage of transmission capacity; largely independent of longer-term contract arrangements.

- **Facilitate Longer-Term Contracting and Competitive Entry** – Spot market reduces the risks of contracting; Allows contracting parties to sell “overs and unders” to meet their obligations at least cost/highest profits, facilitates entry by undiversified competitors, each of which can compete in the specific activity it does best without needing to be a self-contained, full-service producer; sends price signals regarding when and where new generation or transmission is needed.

Policy-makers focus too much on the first objective – understandable given the difficulty of designing a spot market that mimics the operations of the technically oriented dispatch process which we had before deregulation.

The primary purpose of a spot market is to allow market forces to determine the amount, mix and cost characteristics of generating plants, and the level and shape of demand, **in the long run**. This is where the largest benefits are expected from a well-designed competitive market.
Evidence From Market Performance:

- Annual Compensation for New Generators
- ISO Price-setting During Scarcity
Market Performance

- With the SMD initiative, FERC appropriately looks at the LMP systems in PJM and NYISO as a template.

- In designing SMD, 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?

- 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 had some/fewer scarcity conditions in NYISO and ISO-NE due to tight reserves, but had cooler Summer weather, potentially dampening spot prices.

- 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.

**Finance Assumptions**
- 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

**Annual Revenue Requirement**
- High: $120/kw-yr
- Low: $105/kw-yr

**Simple Pro Forma Financial Model**

- 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?

<table>
<thead>
<tr>
<th>Optimal Dispatch Model Output</th>
<th>Average Energy Margin ($/kw-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISO-NE</td>
<td></td>
</tr>
<tr>
<td>2000</td>
<td>75.9</td>
</tr>
<tr>
<td>2001</td>
<td>72.2</td>
</tr>
<tr>
<td>2002</td>
<td>61.2</td>
</tr>
<tr>
<td>NYISO Zone G DAM</td>
<td></td>
</tr>
<tr>
<td>2000</td>
<td>78.3</td>
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<tr>
<td>2001</td>
<td>79.6</td>
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<tr>
<td>2002</td>
<td>73.6</td>
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<tr>
<td>PJM PECO Zone</td>
<td></td>
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<tr>
<td>2000</td>
<td>30.1</td>
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<tr>
<td>2001</td>
<td>53.4</td>
</tr>
<tr>
<td>2002</td>
<td>44.2</td>
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</tbody>
</table>
## 2000-2002 Energy-only Revenue of Merchant CC

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

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

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-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)
  - Assuming 65% capacity factor, energy margin needs to increase by $2.9-3.9/MWh
  - Increase in energy margin represents approximately 12% increase in energy price needed

- NYISO
  - $35-41/kw-yr shortfall annually (30-36% relative to entry cost)
  - Assuming 65% capacity factor, energy margin needs to increase by $2.6-3.0/MWh
  - Increase in energy margin represents approximately 6-8% increase in energy price needed

- PJM
  - $62-71/kw-yr shortfall annually, excluding 2000’s cool Summer (54-62% relative to entry cost)
  - Assuming 45% capacity factor, energy margin needs to increase by $4.6-5.3/MWh
  - Increase in energy margin represents approximately 14-19% increase in energy price needed
  - 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.

<table>
<thead>
<tr>
<th>ISO-NE</th>
<th>Pool / Year</th>
<th>Average Energy Margin ($/kw-yr)</th>
<th>Capacity Payment (Historical Spot Data) $/kw-yr</th>
<th>Capacity Payment (Current Forward Market $/kw-yr)</th>
<th>Levelized Entry Cost ($/kw-yr)</th>
<th>Levelized Return with Historical Capacity Price ($/kw-yr)</th>
<th>Levelized Return with Forward Capacity Price ($/kw-yr)</th>
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<tr>
<td></td>
<td>2000</td>
<td>75.9</td>
<td>-</td>
<td>8.4</td>
<td>115.0</td>
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<td>(43.8)</td>
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<td>7.3</td>
<td>115.0</td>
<td>(70.7)</td>
<td>(63.5)</td>
</tr>
</tbody>
</table>

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 Calendar 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 RTS, “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.
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

<table>
<thead>
<tr>
<th>Day</th>
<th>Hour End</th>
<th>Clearing Price ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6/26/2002</td>
<td>14</td>
<td>102</td>
</tr>
<tr>
<td>6/26/2002</td>
<td>15</td>
<td>147</td>
</tr>
<tr>
<td>6/26/2002</td>
<td>16</td>
<td>126</td>
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<tr>
<td>7/23/2002</td>
<td>14</td>
<td>348</td>
</tr>
<tr>
<td>7/23/2002</td>
<td>15</td>
<td>337</td>
</tr>
<tr>
<td>8/5/2002</td>
<td>15</td>
<td>137</td>
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<tr>
<td>8/5/2002</td>
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<td>8/5/2002</td>
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<td>8/5/2002</td>
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<td>8/19/2002</td>
<td>17</td>
<td>105</td>
</tr>
<tr>
<td>8/19/2002</td>
<td>18</td>
<td>105</td>
</tr>
</tbody>
</table>
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

Prices on 4 of 6 OP-4 Days
Reflect no Scarcity
Premium
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, but 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.
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: 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 3: 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 4: No market power (materiality and sustainability).
  - 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. This emphasis may actually be reducing market efficiency.
Mechanisms of “Bad” Scarcity Pricing
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
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.
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.
Policy Implications for:

- SMD/ISO/ITP Pricing Rules
- Market mitigation
- Installed reserve/adequacy market design
Northeast ISOs are slowly moving to fix the problem. FERC’s SMD should direct ITPs to implement “good” scarcity pricing from the outset. At a minimum, this should be a condition for implementation of AMP-style mitigation other than in load pockets.

The ISOs, RTOs and ITPs should implement “good” scarcity pricing:

- Establish costs for all demand reduction actions
  - Actions that are implemented first under scarcity should have higher costs than actions implemented later.
  - OOM demand reduction actions such as interruptible load programs, voltage reduction, or load shedding should be given appropriate shadow prices that reflect the order in which they are undertaken.

- Ensure that emergency purchases are allowed to set market prices - The alternative is a perverse sequence of events, where the more severe the shortage or scarcity, the lower the market clearing prices.

- Ensure that use of reserves for energy during scarcity are appropriately priced
- Put explicit shadow prices on the overload of transmission lines.

- Allow units that are “flagged” OOM, to set price if it actually turns out that they are in merit.
Policy Implications
Market Mitigation

- Evidence from market performance suggests that $1000 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.

- FERC SMD criteria is the right approach for AMP-style conduct and impact thresholds.
  - “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].

- Using the SMD criteria, AMP-style conduct and impact thresholds – which are targeted at high prices – are not justified based on actual market performance in the Northeast.
Criteria for implementation of AMP-style conduct and impact thresholds:

- **“Calibrated” so as not to suppress prices**
  - At a minimum, application of these mitigation measures should require the ITP to first demonstrate that it has implemented efficient pricing under scarcity.

- **Show that the mitigation measures are necessitated by “unusual circumstances” such as a sustained period of prices significantly above competitive levels or infrastructure problems**

- **Suspend the measures when the unusual circumstances are over and the market has returned to normal.**

NYISO’s AMP and ISO-NE’s proposed first-level mitigation thresholds, do not meet these criteria.
Policy Implications

Reserve Obligations / Capacity Markets

- In a competitive market, all suppliers that are needed for system reliability must be compensated enough in the long run either
  a) to recover their fixed costs and avoid closing, or
  b) when additional capacity is needed, to provide adequate incentive to entry
  c) Provide adequate incentive for development of demand response.

- A competitive market could work without capacity payments.
  - But this would require far greater tolerance of price spikes and high 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
  - 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.
Some basic principals were developed in the JCAG (Joint Capacity Adequacy Group) group. What is needed is:

i) A process that actually assures the physical adequacy of the system through the commitment of generation resources to the ISO/RTO

ii) A process that is fair: No participants are given a “free ride” by enjoying the reliability benefits of sufficient capacity which is paid for by others

ii) The most efficient way to minimize the total level of payments to meet this reliability target

iii) The most efficient and equitable way to collect payments

iv) A process that is compatible with other market requirements, in particular retail access

v) A process that reveals the long run marginal cost of capacity in the market

vi) A process that results in stable price signals to both supply and demand

vii) A process that encourages new entry into the market via generation or demand side management through stable long term price signals

viii) A process that is transparent.
Policy Implications: Capacity Markets
Centralized ICAP Procurement with 2-3 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 (2-3 years).
- Cost of capacity procured by the ISO is charged to end users through a non-bypassable fee – just like transmission.
  - Retail suppliers who do a poor job of purchasing capacity are off the hook.
- Winning bidders (Gencos / marketers / utilities 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).