Capacity Markets: Principles & What’s Happening in the US

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Outline

1. Why markets for capacity?
2. Design choices
3. Designing the PJM market (“RPM”)
   • Dynamic simulation
4. Have capacity markets delivered?
5. Conclusions
1. Why Markets for Capacity?

• Adequacy $\equiv$ Sufficient installed generation & transmission capacity to:
  – Meet electric load with acceptable P(outage)  
    ....engineering definition
  – Clear market; P’s/Q’s at efficient levels  
    .... economics definition

• Who’s responsible?
  – In a market, individual generators not responsible for (engineering) adequacy
  – Governments are! Directive 2005/89/EC:
    • ‘The guarantee of a high level of security of electricity supply is a key objective for the successful operation of the internal market ...'
    • ‘Measures which may be used to ensure that appropriate levels of generation reserve capacity are maintained’
Why Not Just Use Energy Markets?

• Saint Fred’s (Schweppes) 1978 vision of a demand-responsive market unfulfilled
  – Demand-side market failures lead to wrong P’s, capacity shortages

• Reasons:
  – No market information on value of reliability
    • Height of price spikes reflect:
      – regulatory decisions
      – willingness of ISOs and suppliers to stomach political fallout
    • Least valued uses not curtailed during shortages
    • Long-term contracts with consumers infeasible
      ⇒ Optimal amount of capacity unlikely under a pure energy market

  – Bid & price caps in response to market power
    ⇒ ‘Missing money’ – energy revenues don’t cover peaker fixed costs

• Cost of overcapacity << Cost of undercapacity
  ⇒ Capacity markets = insurance
In response to California melt-down:

– (l)n this highly integrated business, where the system requires everyone, and not just the visionary, to be prudent or face losing service and paying high spot prices, enforced customer-side planning ahead will be a small price to pay to avoid ... periodic reliability crises with energy price booms followed by price busts

(FERC Chairman Hoecker, 4 Jan. 2001, Docket Nos. EL00-95-000,002,003)
2. Design Choices

Key to Power Market Design: *Balance the Three Dials*  
(thanks to Steve Stoft)

- **Energy Market**
- **Ancillary Services Markets**
- **Capacity Markets**

- Dials: scarcity pricing, market power mitigation rules, ...
- Settings should:
  - *Prevent market power abuse*
  - *Provide appropriate investment incentives*
    - **Ample** when generation shortage
    - **Absent** under surplus
How Can Market Designers Respond?

1. Demand-side / pricing reforms
   - Correct the market failure
2. Mandatory contracts ("bottom up")
3. Capacity markets ("top down")
ICAP Variant: Demand Curves for Capacity

New systems: Administrative payment from ISO depends on reserve margin

Old ICAP systems: fixed requirements, with penalty for falling short (“vertical demand”)
Status of Capacity Markets in North America

- Alberta Electric System Operator
- Midwest ISO
- Ontario Independent Electricity System Operator
- New Brunswick System Operator
- ISO New England
- New York ISO
- PJM Interconnection

**Mandatory capacity markets**

GW Installed Capacity

Alb. ESO CAISO ERCOT ISO-NE MISO NB SO NYISO Ontario PJM SPP
Desirable Design Features

• Reward availability when & where valuable
  – Scarcity pricing in energy market
  – Penalize plant unavailability during shortages

• Pay all capacity
  – Reward renovation as well as new-build
  – Don’t discriminate among capacity types
  – Pay transmission & demand-response
    • Beware double-payments

• Avoid exacerbating volatility

• Pay locationally

• Contract 2-3 years ahead

• Allow opt-out, with penalties for leaning on system

• Adapt
3. Designing PJM’s Capacity Market with A Risk-Averse Agent Model
Overview of PJM “Reliability Pricing Model” (RPM)

1. Previous PJM system: ICAP
   - Vertical demand curve
     - *Volatile prices: Discouraged risk-averse investors*
   - One market covering PJM
     - *Didn’t reflect locational value: capacity in wrong places*
   - Short-term (annual, monthly, daily markets)
     - *Insufficient forward signal*

2. RPM proposal:
   - Locational 3 yr-ahead prices, sloped demand
   - Development schedule:
     - Stakeholder process, JHU analysis 2004-2005
     - August 2005: initial filing
     - Settlement talks, Fall 2006, JHU reanalysis
     - FERC approved settlement, Dec. 2006
     - Implemented: June 2007
Dynamic Analysis: Questions

1. How do different RPM curves affect....
   • **Stability of capacity market?**
   • **Costs to consumers?**
   • **Ability to meet reserve requirement, reliability criterion?**

2. How robust are these conclusions to different assumptions about....
   • **Generator behavior?**
   • **Demand curve parameters?**
PJM Dynamic Analysis: Basic Assumptions

- Capacity additions are a dynamic process, depending on:
  1. Forecast revenue streams
     - More forecast net revenue → more investment
  2. Revenue stream variability
     - Due to forecast changes, economic fluctuations, & weather
       - Highly variable energy and capacity prices
         - less investment (due to risk aversion)
         - boom/bust cycles
  3. Risk attitudes:
     - Risk aversion
     - Short-sightedness

- Simulate peaker profitability/investment over time
  - Representative agent model
  - Simple representations of:
    - Risk aversion
    - Forecasts of energy, ancillary services, capacity revenues
    - Investment rules
Initial PJM Analysis: 5 Curves Considered

[Graph showing various curves and data points, depicting the relationship between the ratio of unforced reserve to target unforced reserve margin and the cost per unit of unforced MW-year.]
1. Sloped curve stabilizes capacity payments

2. More stable payments even out investment, forecast reserves

3. More stable revenues lowers capital costs. Consumer costs (capacity, scarcity) fall:
   - $127/peak kW/yr for vertical
   - $71/peak kW/yr for sloped curve
   (values depend on assumptions)

4. Results robust
But misguessing the “Cost of New Entry” can affect system performance

Average % by which actual reserve margin exceeds target

CONE Assumed by Curve (actual developer CONE fixed at $72,000/MW/yr)

Changing PJM Demand & Supply Curves Over Time

PJM Conclusions: Advantages of Sloped Demand

• Compared to vertical demand, lower risk to generators. Result:
  – Lower required return to capital
  – More investment in generation
  – Dampened capacity cycles
  – Lower consumer cost

• More advantageous if generators more risk averse
  – Risk neutrality $\Rightarrow$ sloped demand unnecessary
4. Have Capacity Markets Delivered? PJM & ISO-NE

Breakdown of New & Retained Resources

Brattle Report Conclusions

• RPM successfully achieved its reliability & economic objectives
  – Attracted resources
    ~10,000 MW of additional new capacity
    ~4,500 MW of capacity that would otherwise have retired

• Recommended maintaining basic design elements
  – sloped demand curve
  – 3-year forward time frame

• The “Forward Capacity Market” has cleared large amounts of new capacity

5. Conclusions

• Challenges to capacity markets (Brattle et al.)
  – Political consequences of explicit capacity costs
  – Contentious administrative decisions:
    • Right amount of capacity?
    • CONE?
    • Load forecast?
  – Monitoring/verifying demand response
  – Tension between short- (demand) & long-term (gen) resources
  – Transition to “promised land” of energy-only markets
  – Buyer market power
• S. Newell, A. Bhattacharyya, and K. Madjarov, Cost-Benefit Analysis of Replacing the NYISO’s Existing ICAP Market with a Forward Capacity Market, June 15, 2009, The Brattle Group, Prepared for NYISO.
New Generation Capacity Breakdown in PJM

Cumulative Installed CAP (MW)

Month of Auction

delivery Year

Apr 2007 2007/08
Jul 2007 2008/09
Oct 2007 2009/10
Jan 2008 2010/11
May 2008 2011/12

Source: Brattle analysis of PJM RPM data.

Note: A small amount of new oil (~21 MW), retired oil (~46 MW), and retired gas (~11 MW) not shown.