Dealing with Variability & Uncertainty in Electricity Markets:
Some Reflections on California’s Experience

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I. California history

II. Today’s CAISO market design challenges

III. A look at:
   1. Incenting flexibility to accommodate renewables
   2. Capacity credit for variable renewables

IV. Konclusion: Kontinue to Kludge?
I. Market Design is About Getting the Incentives Right: *California History*

- 1996: AB 1890 passed unanimously
  - Unbundled vertically; integrated balancing areas
  - PX traded power *day-ahead*
    - Three zones, disregarded other transmission constraints
    - No forward contracting allowed
  - CAISO then ran *balancing* market to ensure feasibility ("incs" and "decs")
The 2000–2001 Crisis: Example Problems

1. No forward contracting → incentive to take capacity off-line (market power!) (LoPrete & Hobbs, Energy J, 2015)
   - “7 Plagues of Egypt”
   - Wholesale power bill → $20B
   - 38 rotating blackouts in 2001

2. Ignore constraints → incents “dec” game:
   - Generators in “gen pocket” overschedule in high-price zone...
   - …Then buy back power at lower price in real-time
CAISO Response: MD02, MD03, ..., 2009 MRTU (Market Redesign & Technology Upgrade)

- **Features of Market Redesign:**
  - DA & RT markets with arbitrage
  - Co–optimized energy & ancillary services
  - State–imposed forward contracting requirements
  - Locational marginal pricing
  - Financial transmission rights

- **Prices are competitive**
II. Today’s Challenges in CAISO markets

- **California AB32 Cap & Trade:**
  - Goal: Reduce CO₂ by 2020 to 1990 levels
  - Allocate allowances to power plants, & trade
  - Extended in 2017 to 2030

- **Regional Integration:**
  - PacifiCorp (5 states) wants to fully join CAISO
  - Energy Imbalance Market with 11 other utilities
Today’s Challenges, Cont.

- **Renewable Policy:**
  - 33% of electricity by 2020, 50% by 2030
  - But restrict imports

- **Integrating Distributed Resources:**
  - CAISO behind other markets in demand response
  - “Transmission Access Charge”
    - Avoided by behind-the-meter distributed & bulk renewables
    - But paid by front-of-meter distributed resources
  - Inflexible & high retail rates favor behind-the-meter renewables
How can we....?

- Support flexible “backup” capacity for renewables?
- Appropriately reward contributions to system reliability (capacity credits)?
- Expand market, & preserve “environmental integrity”?
  - Account for out-of-state CO$_2$ emissions
  - Facilitate development of least-cost renewable resources
- Promote efficient transmission construction?
  - Planning methods
  - Allocating costs
- Incent the right mix of distributed & centralized resources?
  - Distribution cost allocation
  - Elon’s proposal for special distributed storage rates
Stakeholder engagement opportunities

Current initiatives
- Aliso Canyon gas-electric coordination
- Bid cost recovery enhancements
- Bidding rules enhancements
- Black start and system restoration phase 2
- Commitment costs
  - Commitment cost enhancements phase 3
  - Commitment costs and default energy bid enhancements
- Congestion revenue rights clawback rule modification
- Contingency modeling enhancements
- Demand response
  - Demand response net benefits test
- Energy storage and distributed energy resources
  - Energy storage and distributed energy resources phase 1
  - Energy storage and distributed energy resources phase 2
- Expanding metering and telemetry options
- Flexible resource adequacy criteria and must offer obligations
- Frequency response phase 2
- Generator contingency and remedial action scheme modeling
- Generator interconnection driven network upgrade cost recovery

Load serving entity definition refinement
Local market power mitigation enhancements 2015
Metering rules enhancements
Pricing enhancements
Reactive power requirements and financial compensation
Reliability services
Review transmission access charge wholesale billing determinant
Revised settlement statement and dispute timeline for T+35M
Self-schedules bid cost recovery allocation and bid floor
Stepped constraint parameters
Transmission access charge options
All regional integration stakeholder activities

Recurring stakeholder processes
- 2016-2017 transmission planning process
- Budget and grid management charge process
- Flexible capacity needs technical study process
- Interregional transmission coordination
- Local capacity requirements process
- Participating transmission owner per unit costs
- Stakeholder initiatives catalog process

Energy Imbalance Market activities
- EIM Governing Body draft guidance document web conference
- All active and archived EIM stakeholder activities

Regional energy market initiatives
- Regional energy market
- Metering rules enhancements
- PacifiCorp participation study
- Regional integration and EIM Greenhouse Gas Compliance
- Regional resource adequacy
- Tariff clarifications filing process

Initiatives in implementation phase
- Commitment cost enhancements phase 2
- FERC order no 764 market changes
- Frequency response
- Merced Irrigation District transition
- Pay for performance regulation
- Payment default allocation
- Reliability must-run pump load
III. A detailed look at two issues:  

**Issue 1: Flexibility (“Ramp”)**

![Diagram showing net load from March 1 to March 31, with curves for years 2012 to 2020, demonstrating potential overgeneration and increased ramp.](http://fishwrecked.com/files/boat%20ramp.bmp)
Should it be rewarded by the spot or capacity market?
- In theory:
  - Let’s reward ability to deliver *when needed*
  - Energy price volatility supports optimal ramp

But averaging over 5, 15, 60 minute intervals dampens signals
- also misses lumpy costs (start ups)
Simple model proves: energy prices in theory suffice to support optimal ramping decisions. Example:

A system with two types of generation:

- 1000 MW of quick start peakers @ $70/MWh
- 2100 MW of slow thermal @ $30/MWh, with max ramping = 600 MW/hr

Morning ramp up and resulting generation:

Only failures in the spot market justify creation of a ramp product
**Spot market fixes:** If energy prices insufficient, then add new reserve products
- “Flexiramp” (headroom up and down for next interval) (Wang & Hobbs, IEEE TPWRS 2015)
- “Mileage payments” for frequency regulation
- Both fetch surprisingly low prices

**Capacity market fix:** FRACMOO: Flexible “Resource Adequacy” (capacity market) requirement
- But how do you compare the following?
  - Fully dispatchable turbines
  - Renewables that can turn down
  - 1 start/day resources
  - 4 calls/mo demand response
  - Fly wheels (15 minutes stored)

→ The problem of kludges
Issue 2: How much capacity credit to give to renewables?
Rationale for capacity markets

- **Market failure:** (1) Caps on energy P’s & (2) absence of markets for long-term contracts
  - generators do not earn the full value of their production during periods of scarcity
  - generators can’t hedge long-term risks
  - **underinvestment**

- **Policy response:** Markets for capacity in several ISOs
  - **PJM Reliability Pricing Model** (administrative demand curve for centralized 3 yr-ahead capacity market) (Hobbs et al., *IEEE TPWRS*, 2008)
  - **CAISO:** requirement 1 yr ahead for “capacity showing” by load serving entities, met through bilateral contracts

- **Issue:** what “credit”/capacity payment to give to renewables …. ....and what (if any) distortions result from the wrong credit?
Market simulations of alternative capacity credit levels

What are welfare effects of giving the wrong credit?

- **Energy P Cap $1,000/MWh;**
  - \( CC_{Wind} = 40\% \), \( CC_{Solar} = 75\% \)

- **Energy P Cap; No capacity credit**

- **OPTIMAL:**
  - \( CC_{Wind} = 10\% \), \( CC_{Solar} = 54.5\% \)
Mechanisms for “resource adequacy” (contribution of resources to system reliability) is a state responsibility, but a multistate market must have a consistent approach:

- If a perfectly reliable, flexible resource gets $X/MW/yr...
  ...how much should other resources get paid?
- **Proposal:** “Effective Load Carrying Capability”

**Devilish details:**

*Settlements*

- Locationally differentiated?
- Penalize larger thermal resource?
- Account for operating constraints (flexibility)?
- Average or marginal ELCC?

**Fig. 5. Capacity Value of Wind Power with increasing wind penetration**

(Source: Keane et al., IEEE TPWRS, 26, 2011, 564–572)
IV. Conclusion: When ought we kludge…

…and when start from scratch?


In July of 2004, Microsoft announced that the release of Vista, the next generation of the Windows operating system, would be delayed until late 2006. Jim Allchin famously walked into the office of Bill Gates and proclaimed, “It’s not going to work.” Development of Windows had become unmanageable and Allchin decided that Vista would have to be rewritten essentially from scratch.

Mr. Allchin’s reforms address a problem dating to Microsoft’s beginnings. PC users wanted cool and useful features quickly. They tolerated—or didn’t notice—the bugs riddling the software. Problems could always be patched over. With each patch and enhancement, it became harder to strap new features onto the software since new code could affect everything else in unpredictable ways.¹
Time to shake up the etch-a-sketch?
(thanks to Alison Silverstein)

http://i.imgur.com/oMvr5.jpg
California? More Like COOLIFORNIA!

I wish I were that cool.

I can't even tell who you are.