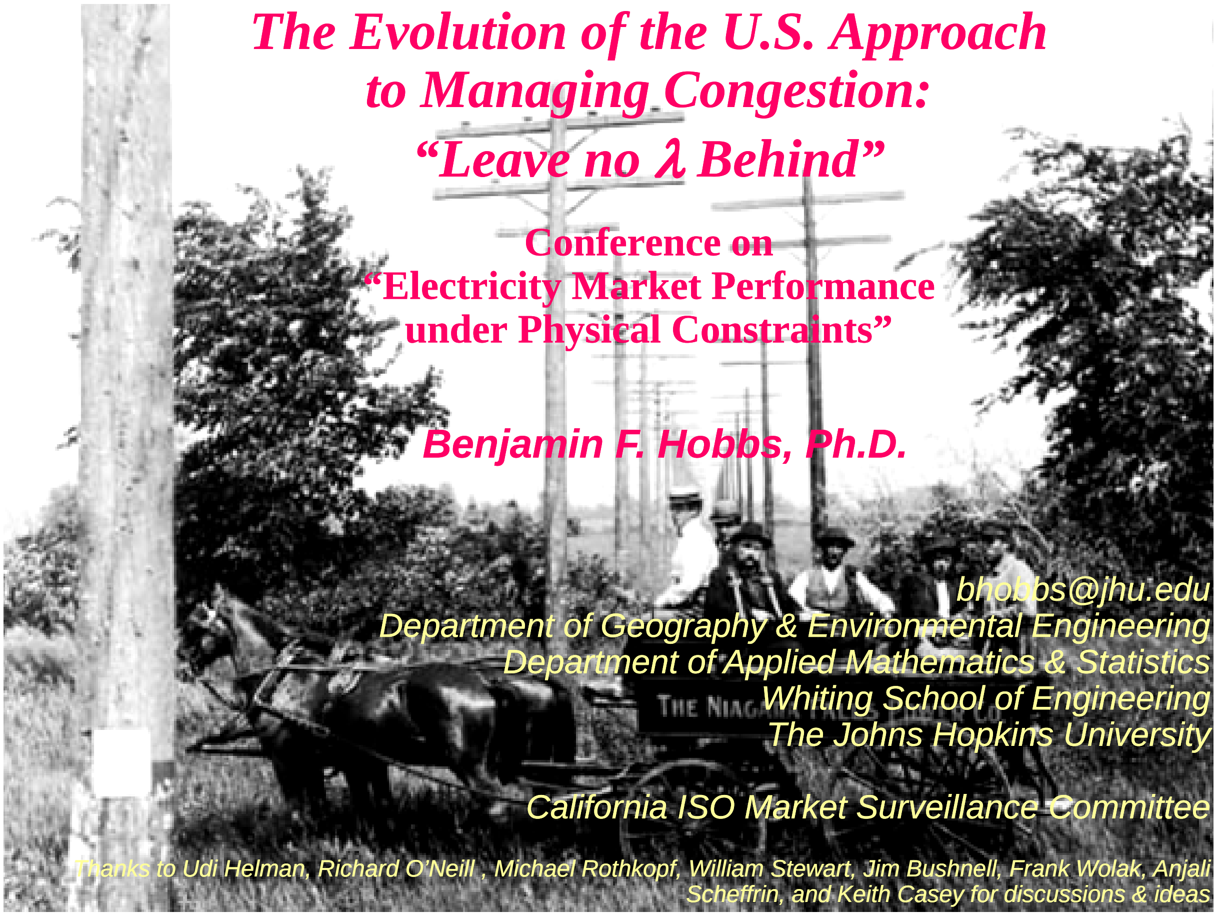

The Evolution of the U.S. Approach to Managing Congestion: "Leave no λ Behind"

Conference on "Electricity Market Performance under Physical Constraints"

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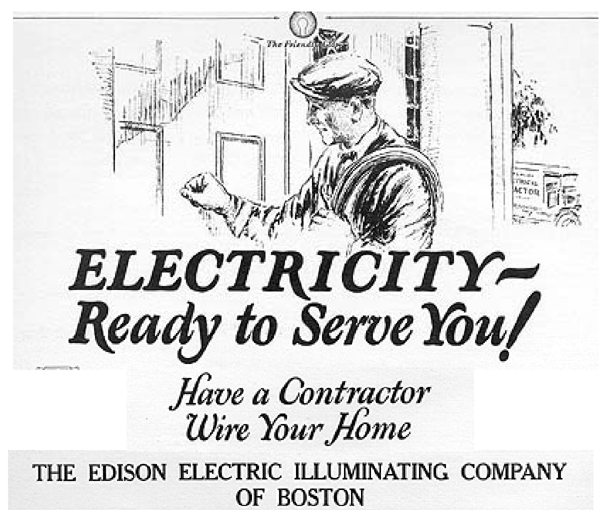
California ISO Market Surveillance Committee

Thanks to Udi Helman, Richard O'Neill , Michael Rothkopf, William Stewart, Jim Bushnell, Frank Wolak, Anjali Scheffrin, and Keith Casey for discussions & ideas

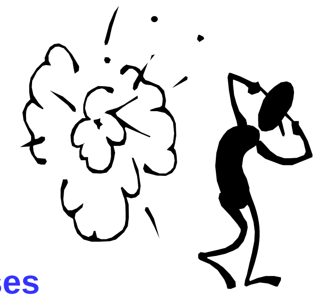
Outline



1. **Some history**
2. **The "LMP" Philosophy**
3. **Examples of "Zonal" problems**
4. **Problems**
   a. **Some left-behind λ's**
   b. **Market power**

1. A Brief History of Regulation and Restructuring in the US

- 400 BC: Athens city regulates flute & lyre girls
- 1978: Public Utilities Regulatory Policy Act
- 1978: Schweppe's "Power Systems 2000" article
- Federal:
  - 1992 US Energy Policy Act
  - FERC Orders 888, 2000
  - FERC "Standard Market Design"
- States:
  - California leads 1995
  - Most states were following
  - Response to California 2000-01: "Whoa!!"
  - Response to FERC SMD, Fuel price increases



April 2003: "~~Standard Market Design~~" "Wholesale Power Market Platform"

FERC's *mea culpa*:

"The proposed rule was too prescriptive in substance and in implementation timetable, and did not sufficiently accommodate regional differences"

"Specific features … infringe on state jurisdiction"

Market Design Principles of "Platform"

- ***Grid operation:***
  - Regional
  - Independent
  - Congestion pricing
- ***Grid planning:***
  - Regional
  - State and stakeholder led
- ***Firm transmission rights***
  - Financial, not physical
  - Don't need to auction

More Principles of "Platform"

- ***Spot markets:***
  - Day ahead and balancing
  - Integrated energy, ancillary services, transmission
- ***Resource adequacy***
  - State led
- ***Market power***
  - Market-wide and local mitigation
  - Monitoring

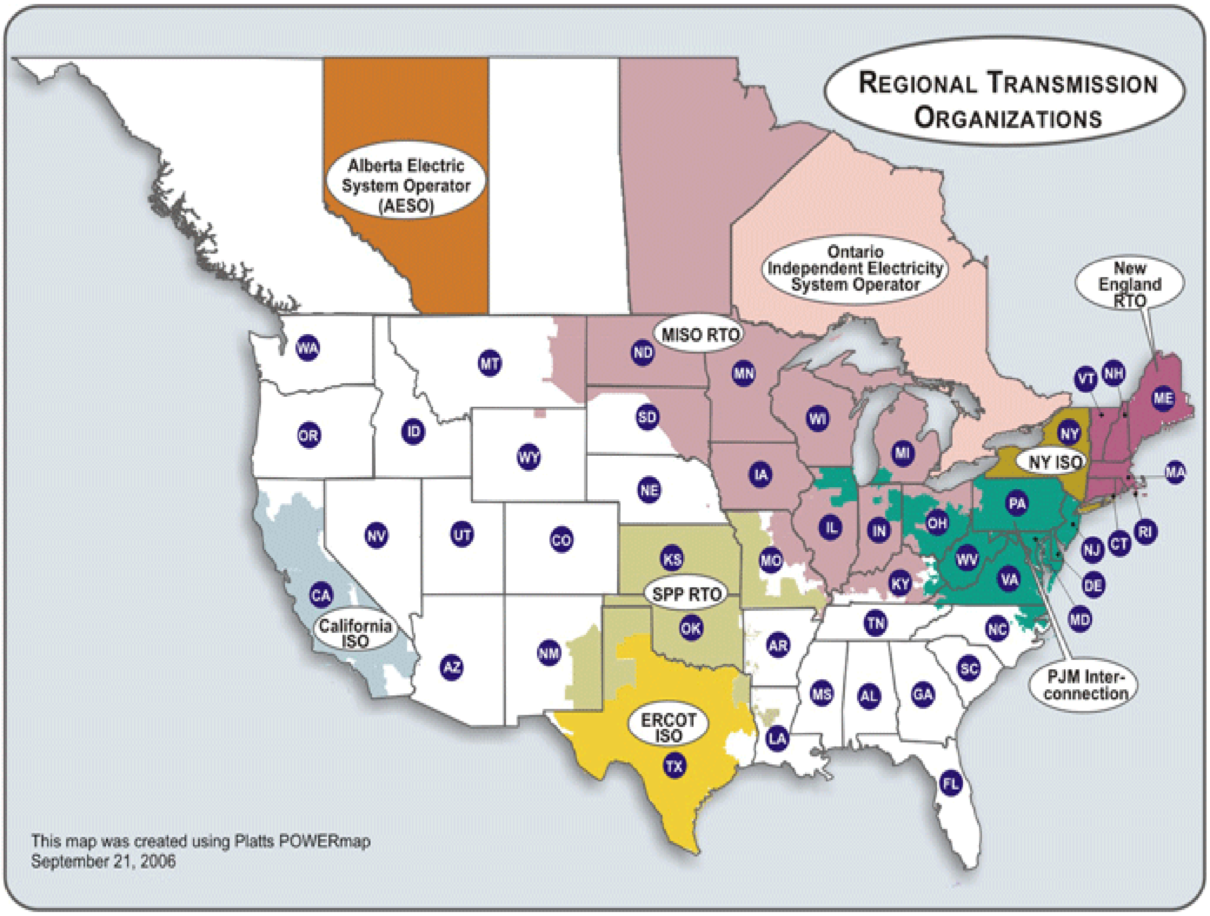


Table 7: Wholesale Electric Markets in 2006

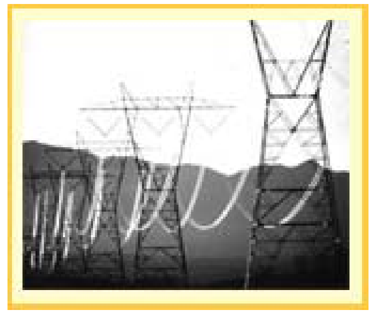
■ Existing □ Projected

	Real-time market (RTO/ISO)	Real-time market Bilateral	Day-ahead market (RTO/ISO)	Day-ahead market Bilateral	Virtual Bidding (RTO/ISO)	Ancillary services markets (RTO/ISO)	Financial transmission rights (RTO/ISO)	Capacity (UCAP) markets (RTO/ISO)	Associated financial markets
New England	■	■	■	■	■	■	■	■[1]	■
New York	■	■	■	■	■	■	■	■[2]	■
PJM	■	■	■	■	■	■	■	■[3]	■
Midwest	■	■	■	■	■	08	■		■
Southeast		■		■					■
SPP	■	■		■					
ERCOT	■	■	09	■		■	■		
Northwest		■		■					■
Southwest		■		■					■
California	■	■	08	■	09	■	■	[4]	■

[1] Transitioning to a formal capacity market. ISO-NE's installed capacity market was replaced on December 1, 2006, with the transition period for its new Forward Capacity Market.
[2] Locational
[3] Systemwide
[4] California is considering a formal capacity market.

2. Locational Marginal Pricing Review

- Price of energy (LMP) at bus i = Marginal cost of energy at bus
  - Most readily calculated as dual variable to energy balance (KCL) constraint for the bus in an Optimal Power Flow (OPF)
- General Statement of OPF
  - Objective ***f***:
    - *Vertical demand:* MIN Cost = Σ Generator Costs
    - *Elastic demand:* MAX Net Benefits
      = Σ (Consumer Value - Generator Cost)
  - Decision variables ***X***:
    - Generation
    - Accepted demand bids
    - Operating reserves
    - Real and reactive power flows
  - Constraints
    - Generator limits (including dynamic limits such as ramp rates)
    - Demand (net supply = load ***L*** at each bus for P,Q)
    - Load flow constraints (e.g., KCL, KVL)
    - Transmission limits
    - Reserve requirements



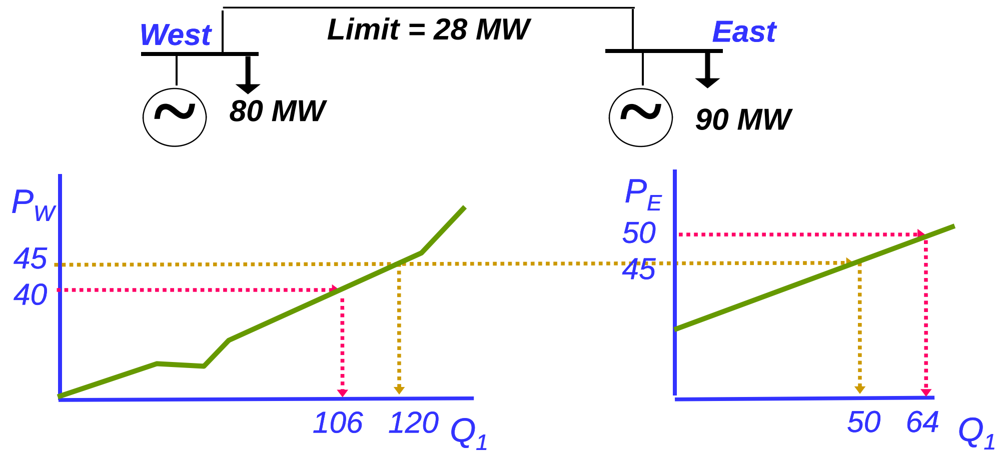
LMP Components

- LMP = Δ Cost resulting from unit change in load
  - d***f***/d***L***
  - Assumes:
    - No change in any integer {0,1} variables
    - No degeneracy (multiple dual solutions)
- Price at bus *i* equals the sum of:
  - *Energy:* Set equal to a "hub" price (e.g., "Moss Landing," or distributed bus)
  - *Loss:* Marginal losses (assuming supply comes from hub)
  - *Congestion:* LMP *minus* (Energy+Loss components)
    - In linear case = Weighted sum of λ's for transmission constraints
    - $= \Sigma_k \, PTDF_{Hub,i,k} \, \lambda_k$

- California ISO calculation of LMPs: Section 27.5 of the CAISO MRTU Tariff www.caiso.com/1798/1798ed4e31090.pdf, and F. Rahimi's testimony www.caiso.com/1798/1798f6c4709e0.pdf

LMP / Congestion Example

(Based on Presentation by Mark Reeder, NYISO, April 29, 2004)

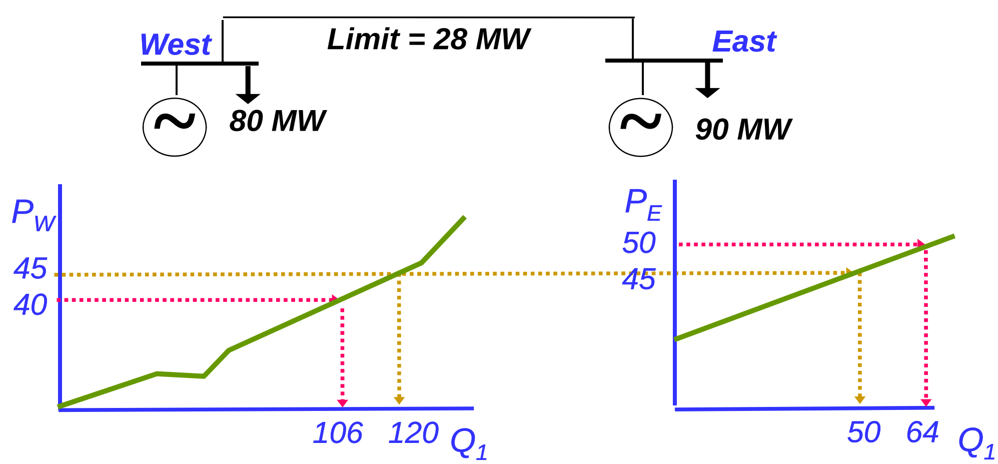


Key: Prices/Supplies under 28 MW limit
Prices/Supplies with no transmission limit

- Marginal value of transmission = $10/MWh (=$50-$40)
- Total congestion revenue = $10*28 = $280/hr

LMP / Congestion Example

(Based on Presentation by Mark Reeder, NYISO, April 29, 2004)

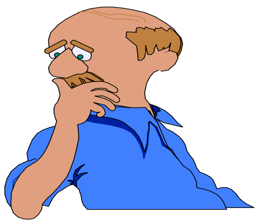


Key: Prices/Supplies under 28 MW limit
Prices/Supplies with no transmission limit

- Marginal value of transmission = $10/MWh (=$50-$40)
- Total congestion revenue = $10*28 = $280/hr
- Total redispatch cost = $140/hr
- Congestion cost to consumers: (40*106+50*64) – (45*170) = 7440 – 7650
  = -$210/hr

Theoretical Results

- Under certain assumptions (Schweppe et al., 1986):
  - Solution to OPF = Solution to competitive market
    - Dispatch of generation will be efficient (social welfare maximizing, including …)
    - Long run investment will be efficient
  - In other words: The LMPs "support" the optimal solution
    - If pay each generator the LMPs for energy and ancillary services at its bus ….
    - ….Then the OPF's optimal solution X_j for each generating firm j is also profit maximizing for that firm
- This is an application of Nobel Prize winner Paul Samuelson's principle:
  - Optimizing social net benefits (sum of surpluses) = outcome of a competitive market



Assumptions

- No market power
- No price caps, etc.
- Perfect information
- Costs are convex
  - No unit commitment constraints
  - No lumpy investments or scale economies
- Constraints define convex set
  - E.g., AC load flow non convex
- Can compute the solution
  - ~10^4 buses, 10^3 generators

3. Failed "Zonal" Pricing: Learning the Hard Way

- California 2004
- PJM 1997
- New England 1998
- UK 2020?

The "DEC" Game in Zonal Markets

- Clear zonal market day ahead (DA):
  - All generator bids used to create supply curve in zone
  - Clear supply against zonal load
  - All accepted bids paid DA price
- In real-time, "intrazonal congestion" arises—constraint violations must be eliminated
  - "INC" needed generation (e.g., in load pockets) that wasn't taken DA
    - Pay them > DA price
  - "DEC" unneeded generation (e.g., in gen pockets) that can't be used
    - Allow generator to pay back < DA price

Problems arising from “DEC” Games

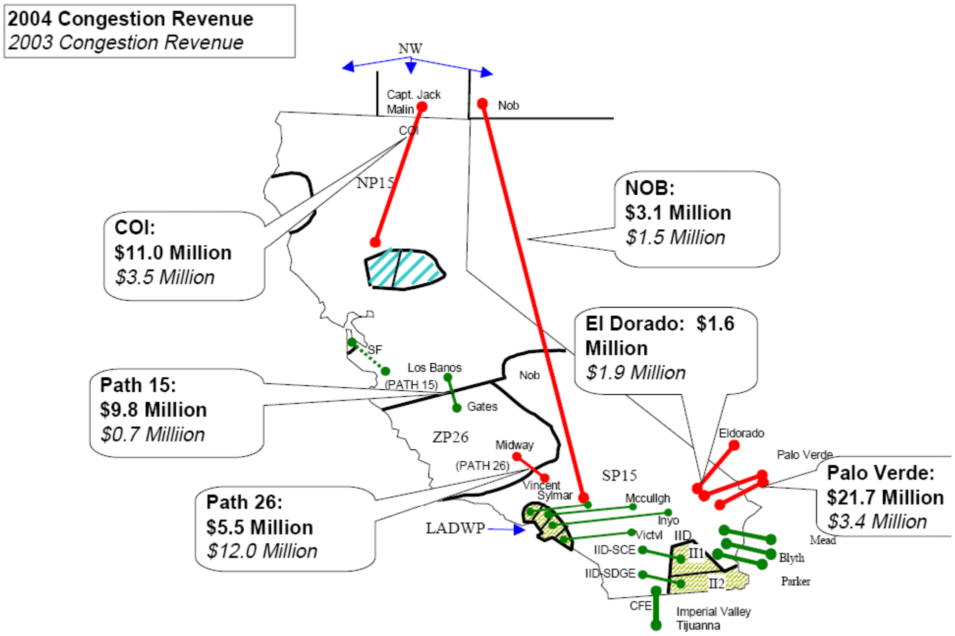
- Problem 1: Congestion worsens
  - The generators you want won’t enter the DA market
  - The generators you *don’t* want will
  - Real-time congestion worsens
- Problem 2: Encourages DA bilateral contracts with “cheap” DEC’ed generation
  - Destroyed PJM zonal market in 1997
- Problem 3: DEC game is a money machine
  - Gen pocket generators bid cheaply, knowing they’ll be taken and can buy back at low price
    - E.g., P_{DA} = \$70/MWh, P_{DEC} = \$30
    - You make \$40 for doing nothing
  - Market power not needed for game (but can make it worse)
  - E.g., California 2004

Problems arising from “DEC” Games

- Problem 4: Short Run Inefficiencies
  - If DEC’ed generators are started up & then shut down
  - If INC’ed generation is needed at short notice
- Problem 5: Encourages siting in wrong places
  - Complex rules required to correct disincentive to site where power is needed
  - E.g., New England 1998, UK late 1990s

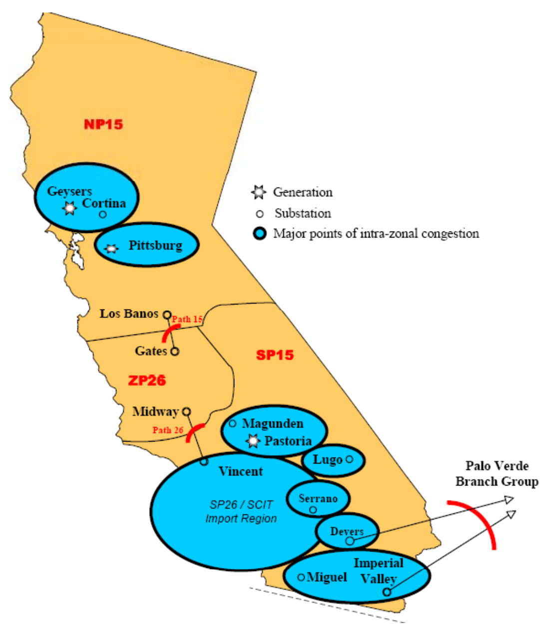
Example 1: Cost of DEC Game in California

- Three zones in 1995 market design
- Cost of Interzonal-Congestion Management:
  - $56M (2006), $55.8 (2004) $26.1 (2003)



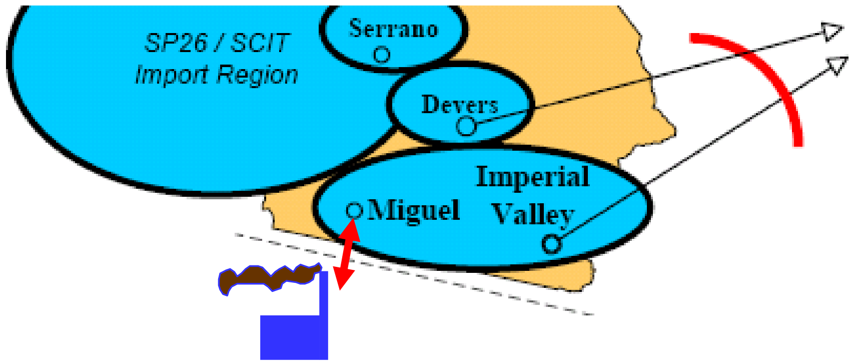
Intrazonal Congestion in California (Real-Time Only)

- $207M (2006), $426M (2004), $151M (2005)
- Mostly transmission within load pockets
- Managed by:
  - Dispatching "Reliability Must Run" and "minimum load" units
  - INC's and DEC's
- Three components (2004):
  1. *Minimum load compensation costs—required to be on line but lose money ($274M)*
  2. *RMR unit dispatch ($49M)* (Total RMR costs $649M)
  3. INC's/DEC's (*$103M*):
     - Mean INC price = $67.33/MWh
     - Mean DEC price = $39.20/MWh



Miguel Substation Congestion

- 3 new units in north Mexico (1070 MW), in Southern California zone
- Miguel substation congestion limits imports to Southern California
  - INC San Diego units
  - DEC Mexican units or Palo Verde imports
- Mexican generation can submit very low DEC bids
  - In anticipation, CAISO Amendment 50 March 2003 mitigated DEC bids
- Nevertheless, until Miguel was upgraded (2005), Miguel congestion management costs ~ $3-$4M/month even with mitigation
  - Value to Mexican generators: ~$5/MW/hr



Example 2: PJM Zonal Collapse

- New (1997) PJM market had zonal day-ahead market
  - Congestion would be cleared by “INC’s” and “DEC’s” in real-time
  - Congestion costs uplifted
- Generators had two options:
  - Bid into zonal market
  - Bilaterals (sign contract with load, submit fixed schedule)
- Hogan’s generator intelligence test:
  - You have three possible sources of power
    - Day ahead: zonal $30/MWh
    - Bilateral with west (cheap) zone: $12/MWh
    - Bilateral with east (costly) zone: $89/MWh
  - Result: HUGE number of infeasible bilaterals with western generation
  - PJM emergency restrictions June 1997
- PJM requested LMP and FERC approved; operational in April 1998
  - The important issue is not the total cost of transmission -- it’s the incentives when congestion occurs

(Source: W. Hogan, Restructuring the Electricity Market: Institutions for Network Systems, April 1999)

Example 3:
Perverse Siting Incentives in New England

- Before restructuring, New England's power pool (NEPOOL) had a single zone and energy price
  - Complex planning process required transmission investment along with generation to minimize impact of new generators on older units
- In response to market opening, approximately 30 GW new plant construction was announced in late 1990s (doubling capacity)
  - To deal with perverse siting incentives, NEPOOL proposed complex rules for new generators, requiring extensive studies of system impacts and expensive investments in the transmission system.
  - Rules would increase costs for entry and delay it, protecting existing generators from competition
- October 1998, FERC struck down rules as discriminatory and anticompetitive responses to the defective congestion management system
  - ISO-NE submitted a LMP proposal in 1999 which was accepted

(See W. Hogan, *ibid.*)

Example 4: UK in 2020?

- UK system's congestion costs have fallen drastically
  - System sized to allow all generators to serve load during the peak
- Can't sustain if add large amounts of intermittent generation
  - If 25% wind, reserve margin ~40%
  - Uneconomic to size transmission to meet peak load from all possible sources
  - ⇒ Congestion would grow
- E.g., two node system:
  - Cheap generation + wind in North
  - High loads and expensive generation in South
  - If all wind available, huge N-S link needed to avoid congestion
- Prompting UK rethinking of NETA congestion management

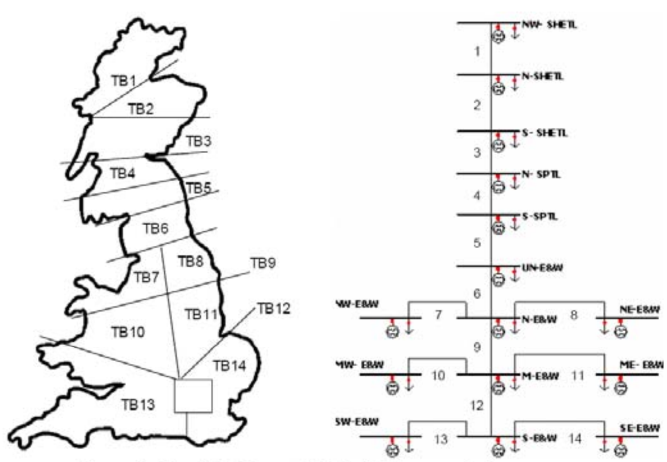
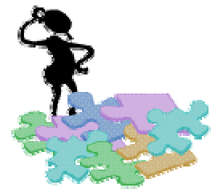


Figure 1: Simplified Great Britain (GB) transmission system

(Source: G. Strbac, C. Ramsay, D. Pudjianto, Centre for Distributed Generation and Sustainable Electrical Energy, "Framework for development of enduring UK transmission access arrangements," July 2007

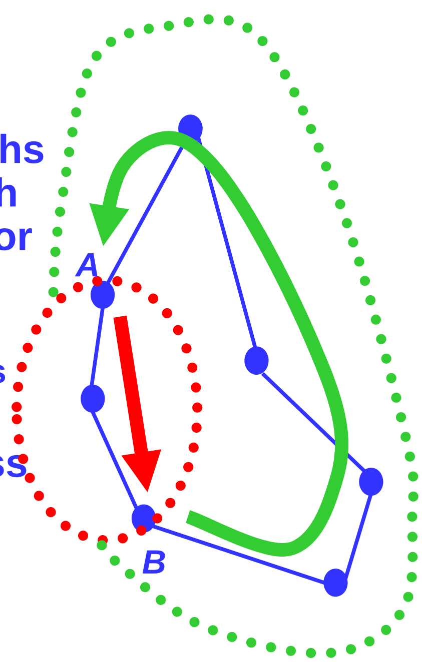
4. Remaining Problems:
a. Left-behind λ's



- Ideally, LMPs should reflect all constraints
- Spatial λ's left behind:
  - "The seams issue" – interconnected systems with different congestion management systems
    - Can lead to "Death Star"-type games ("money machines")
- Temporal λ's left behind:
  - Ramp rates not considered in real-time LMPs
    - Distorts incentives for investment in flexible generation
- Interacting commodity (ancillary services) λ's left behind:
  - Operator constraints not priced
    - Can systematically depress energy prices
- The problem of nonconvex costs
  - Unit commitment (min run, start up costs)
    - Marginal costs ambiguous

Spatial λ's left behind

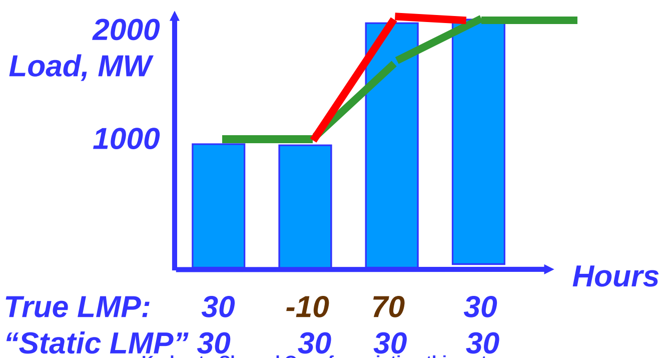
- Green and Red systems interconnect at A and B. They manage congestion differently:
  - Green: LMP-based
  - Red: Path-based
- Power from A to B follows all paths and can cause congestion in both systems: there is one correct P for each & one correct transmission charge
  - But Green ignores Red's constraints and miscalculates LMPs



- If Red's charge from A to B is less than P_A-P_B for Green…
  - *Money machine!* Have a 1000 MW transaction from A to B in Red, and 1000 MW back from B to A in Green

Temporal λ's left behind

- Some ISOs set real-time LMPs considering just constraints active *at* that time ("static optimization")
  - This skews LMPs by ignoring binding dynamic constraints in other intervals
- E.g., a system with two types of generation:
  - 2100 MW of slow thermal @ $30/MWh, with max ramping = 600 MW/hr
  - 1000 MW of quick start peakers @ $70/MWh
- Morning ramp up and resulting generation:



Kudos to Shmuel Oren for pointing this out

Depresses LMP volatility – undervalues flexible generation
- *Crucial with more wind!*
- *Answers:*
  - *Ramp product? (CAISO, MISO)*
  - *Ramp capacity payment? (PJM)*

Other Commodities' λ's left behind

- Operators often call generators "OOM" ("out of merit order") to ensure that important contingency & other constraints met
  - to some extent inevitable
- But if done frequently and predictably, these are constraints that should be priced in the market. Else:
  - Depresses prices for other generators whose output or capacity is helping to meet that constraint
  - Inflates prices for generators that worsen that constraint
  - Could skew investment
- Has been identified as a chronic problem in some U.S. markets by market monitors

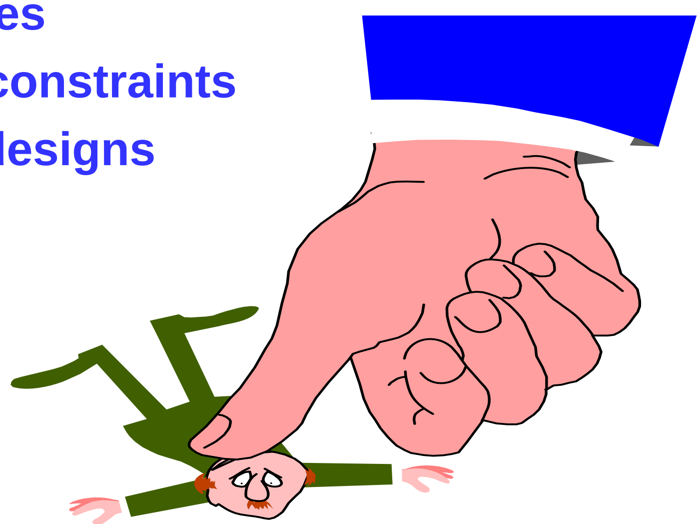
Nonconvex Costs: What are the Right λ's?

- Common situation:
  - Cheap thermal units can continuously vary output
  - Costly peakers are either "on" or "off"
  - ⇒ Even during high loads, LMP set by cheap generators
  - ⇒ Too little incentive to reduce load
  - ⇒ Peakers don't cover their costs ("uplift" required)
  - ⇒ Cheap units may get inadequate incentive to invest
- California, New York solutions:
  - *If* peaking units are small relative to variation in load,
  - … *then* set LMP = <u>average</u> fuel cost of peaker, if peakers running
  - Note: LMP doesn't "support" thermal unit dispatch, so must constrain output
- Alternative: "Supporting prices" in mixed integer programming
  - Calculated from LP that constrains {0,1} variable to optimal level
  - Results in separate prices for supply (thermal plant MC) and demand (higher LMP), and uplifts to peakers
  - Source: R. O'Neill, P. Sotkiewicz, B. Hobbs, M. Rothkopf, and W. Stewart, "Efficient Market-Clearing Prices in Markets with Nonconvexities," <u>Euro. J. Operational Research</u>, 164(1), July 1, 2005, 269-285

4. Remaining Problems: b. Dealing With Market Power

Arises from:

- Inelastic demand / inefficient pricing
- Scale economies
- Transmission constraints
- Dumb market designs



Mark Twain:

"The researches of many commentators have already thrown much darkness on the subject and it is probable that, if they continue, we shall soon know nothing at all about it"

(thanks to Dick O'Neill for the quote)

How to Respond?
Local Market Power Mitigation Questions

- **Who is eligible for mitigation?**
- **What triggers mitigation?**
- **How much Q is mitigated?**
- **What is the mitigated bid?**
- **How are locational marginal prices (LMPs) calculated?**
- **What is the bidder paid?**
- **What if the bidder doesn't cover its fixed costs?**

Various Answers

- *Who is eligible for mitigation?*
  - Everyone
  - Congested areas / load pockets only. How to define?
- *What triggers mitigation?*
  - Pivotal bidder (CAISO MSC [Wolak], Rothkopf)
  - Out-of-merit order (PJM)
  - Automated Mitigation Procedure (NYISO, NEISO, MISO)
    - Conduct threshold (e.g., 200% over baseline bid)
    - Impact threshold (e.g., raise market price by 50%)

- *How much Q is mitigated?*
  - Entire capacity (PJM)
  - Only pivotal/out-of-merit order quantity (California proposals)
- *What is the mitigated bid?*
  - Baseline (mean bid during competitive period, plus negotiated "hockey stick") (MISO)
  - Estimated variable cost (fuel only? maintenance?) (CAISO, PJM)
  - Combustion turbine proxy (NEISO)

- ***How are <u>LMPs</u> calculated?***
  - **Include mitigated bid in locational marginal pricing calculations** **(PJM, CAISO)**
  - **Exclude mitigated bid (put mitigated Q in as price-taker)** **(Wolak)**
- ***What is the <u>bidder paid</u>?***
  - **LMP or MAX(LMP, Variable Cost)**
- ***What if the bidder doesn't cover its <u>fixed costs</u>?***
  - **File for "Cost of Service" contract (ISO may refuse)**

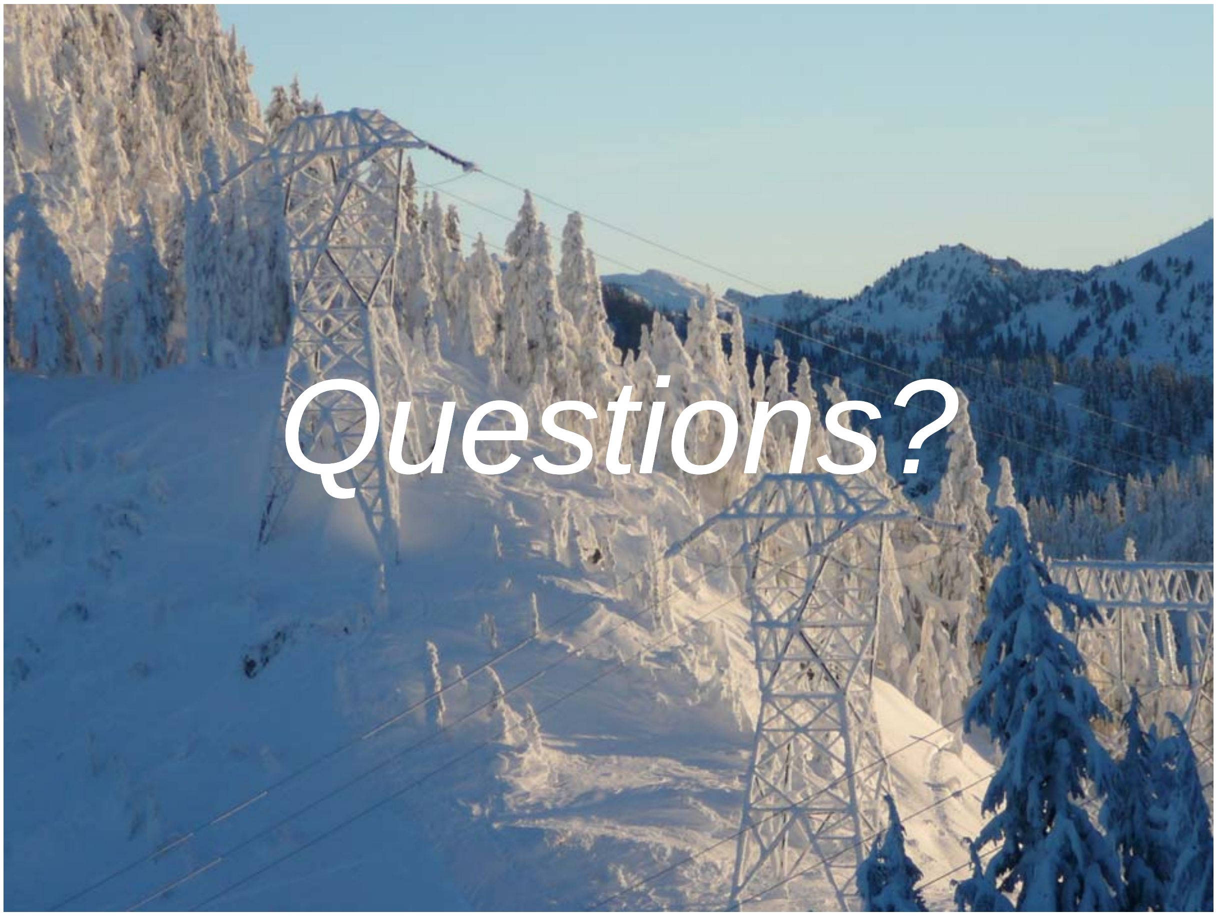
Conclusion

You don't always get it right the first time.

Now you have experience

Try WMP

Thanks to Dick O'Neill, FERC


Questions?