RESTRUCTURING OF POWER INDUSTRY: PRESENT & FUTURE ISSUES AND IMPLICATIONS FOR RELIABILITY

Chanan Singh
Panida Jirutitijaroen
Department of Electrical Engineering
Texas A&M University

Outline

- Overview
- Energy market in different states
  - Pennsylvania-New Jersey-Maryland
  - New England
  - California
  - Texas
- Market failures
  - Market challenges
  - Market rules
  - Reliability issues

OVERVIEW

Before and After

- Integrated Utilities:
  - Generation
  - Transmission
  - Distribution
  - Congestion Management
  - Reliability

- Generation
  - Supply electricity
- Independent System Operators
  - Transmission
  - Congestion Management
  - Reliability
- Retailer
  - Distribute to end consumers

The Fundamental Concept Underlying Reliability

- The fundamental concept is balancing resource (generation and transmission) with demand under uncertainty
- This should be achieved with a specified probability of success.
- The probability may be explicit or implicit

Sources of Uncertainty

- Before restructuring: forced outages of generators and transmission lines and load forecast errors.
- In the restructured environment energy trading mechanism introduces additional source of uncertainty effecting reliability.
- Understanding of energy trading mechanism is important for dealing with reliability issues.

Energy Trading Mechanisms

- Bilateral Contract
  - Direct contract between consumer and supplier: Industrial consumer, Retailer
- Day Ahead Market
  - Auctions
- Real Time Market
  - Balancing market, auctions
- Ancillary Services Market
  - Helps maintain system reliability
- Virtual Bidding
  - Provides mechanism to even out price in Day ahead and real time market

Note:Energy and ancillary services markets are tightly coupled since thes are mostly provided by the same generators.

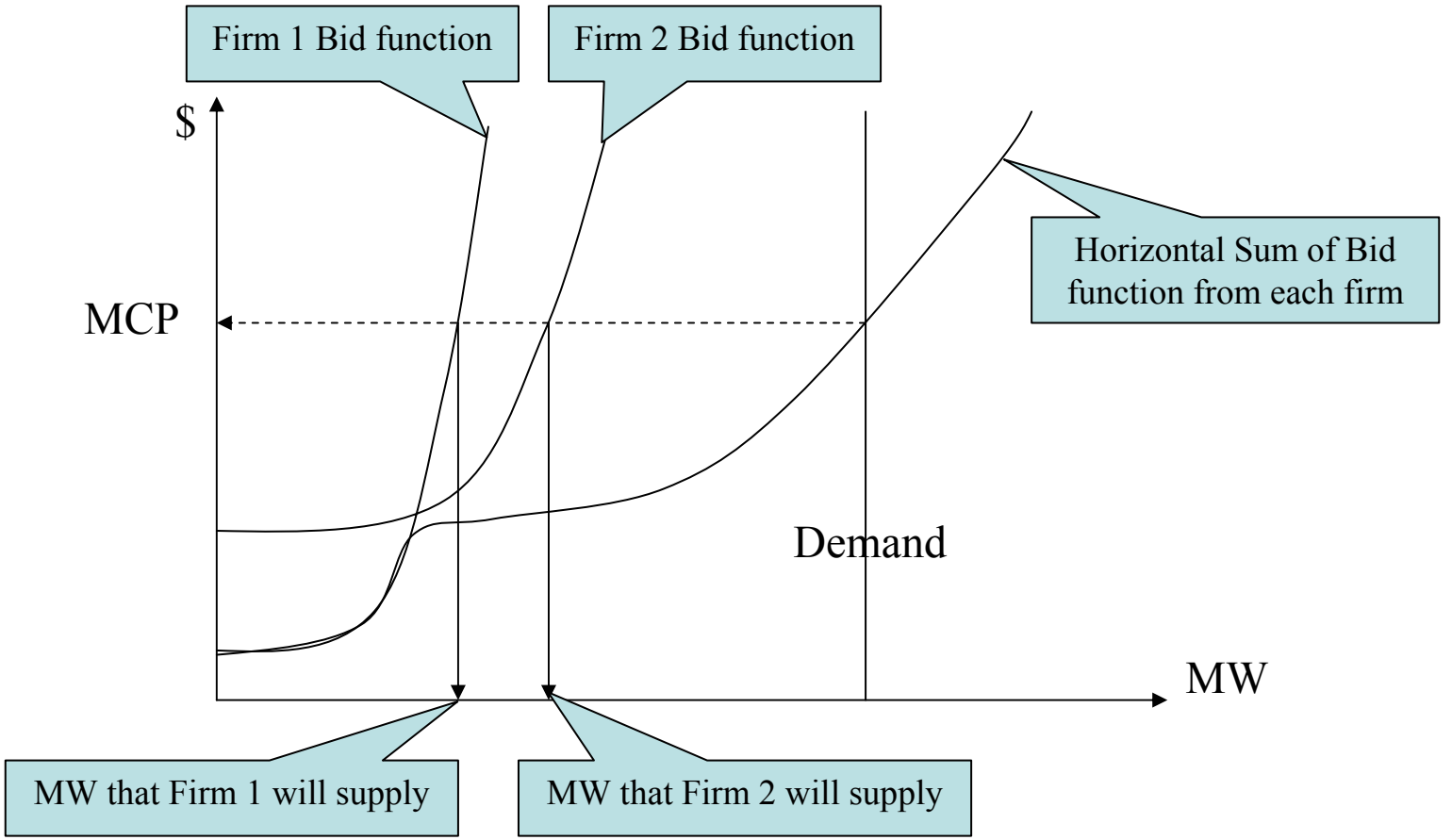
Day Ahead Market

- GenCos submit ‘willingness-to-supply’ function for each hour in the following day
- Market Operators intersect ‘horizontal sum’ of these supplies to inelastic demand

➔Market clearing price for each hour in the following day for day ahead market.

Market Clearing Price (MCP) Calculation

- Intersection of demand and horizontal sum of firms' bid function



Real Time Market

- Electric supply and demand have to be balanced at all times
- ISO is responsible for system reliability and transmission congestion management.
- Different states have different ways to manage congestion.
- Gens submit willingness-to-supply in intervals such as 5/10 mins, ISO intersect this with inelastic residual demand.

➔ Market clearing price for each time interval in real time.

Note that generation companies usually have almost the same supply function for each hour everyday.

Ancillary Services Market

These services are intended to maintain system reliability

- Regulation: maintain system frequency (or AGC)
- Operating reserve: emergency generation in case of contingency, will be classified by the time to response to load
  - Spinning reserve: response fastest
  - Non-spinning reserve
  - Replacement reserve
- Installed capacity market: ensure long term generation adequacy

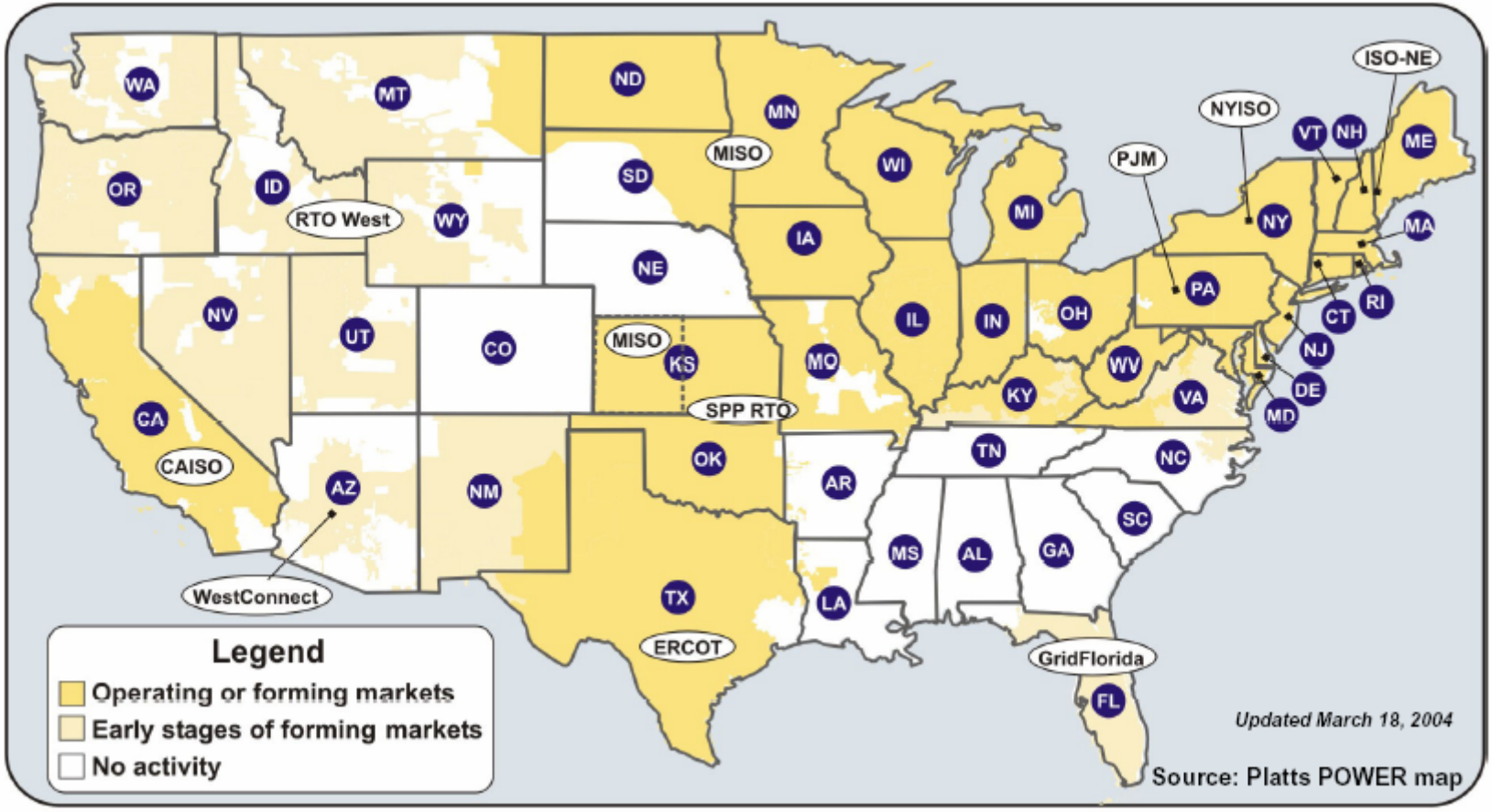
Virtual Bidding

- Why virtual bidding?
  - Day ahead and real time market have different MCP
  - Company could make money by buying energy from cheaper market and sell it in another market
- Characteristics
  - Qualified company can virtually sell or buy electricity
  - Only financial transaction, not physical consumption
  - Company can make bids as virtual supply or virtual demand
- Usefulness
  - Allow other non-energy institution to involve in electric market; such as financial institution
  - Reduce price difference in both day ahead and real time market

Energy Market in Different States

- Market Structure: Ownership
- Market Design: Market Operation/rules
  - Energy Market
  - Ancillary Services Market
- Congestion Management

Market Formation in USA



Different Market Structure in USA

Legend: ■ = Yes ● = No	Bilateral trans-actions	Real-time market	Day-ahead market	Ancillary services markets	Capacity market	Active physical day-ahead ICE market	Futures market	Financial trans-mission rights	Virtual bidding
ISO-NE	■	■*	■*	■*	■* (2)	■	●	■*	■*
NYISO	■	■*	■*	■*	■* (2)	●	●	■*	■*
PJM	■	■*	■*	■*	■* (2)	■	■	■*	■*
ERCOT	■	■*	●	■*	●	■	●	■*	●
CAISO	■	■*	●	■*	●	■	●	■*	●
Southeast	■	●	●	● (1)	●	■ (3) Entergy	●	●	●
Florida	■	●	●	● (1)	●	●	●	●	●
Midwest	■	●	●	● (1)	●	■	●	●	●
South Central	■	●	●	● (1)	●	●	●	●	●
Southwest	■	●	●	● (1)	●	■	●	●	●
Northwest	■	●	●	● (1)	●	■	●	●	●

Updated March 10, 2004

Notes: *Designates a market operated by an ISO. (1) Ancillary services were provided at cost-based tariff rates or negotiated bilaterally. (2) ISO conducts an auction-based capacity market. Bilateral contracts and self-supply were also allowed. (3) Whereas products were available more widely within other regions, products were only available for a single price point in this region.
Source: OMOI.

Price Formation

Legend: ■ = Yes ● = No ◆ = Not market based	Regions with organized markets					Regions without organized markets					
Services Provided	**ISO-NE**	**NYISO**	**PJM**	**ERCOT**	**CAISO**	**South-east**	**Florida**	**Midwest**	**South Central**	**South-west**	**North-west**
Real-time energy market	■	■	■	■	■	●	●	●	●	●	●
Locational energy price	■	■	■	■	■	●	●	●	●	●	●
Hourly energy price	■	■	■	■	■	●	●	●	●	●	●
Congestion price	■	■	■	■	■	●	●	●	●	●	●
Losses price	■	■	● (1)	■	■ (2)	●	●	●	●	●	●
Regional transmission scheduling	■	■	■	■	■	●	●	■	●	●	●
Regional economic dispatch	■	■	■	■ (3)	■ (3)	●	●	●	●	●	●
Regional transmission planning	■	■	■	■	■	●	●	■	●	●	●
Regional interconnection process	■	■	■	■	■	●	●	■	●	●	●
Independent market monitor	■	■	■	■	■	●	●	■	●	●	●

Updated March 10, 2004

Note: (1) Losses are allocated to market participants based on a pro-rata share of total transmission losses. (2) Losses are allocated to sellers using generation meter multipliers, which reflect scaled marginal losses. (3) CAISO and ERCOT did not have day-ahead energy markets; economic dispatch was used in their real-time balancing markets only.
Source: OMOI.

PENNSYLVANIA-NEW JERSEY-MARYLAND (PJM)

Pennsylvania-New Jersey-Maryland (PJM)

- Market structure
  - Most of Utilities divested their generations.
- Market design
  - Day Ahead Market operated by ISO
  - Real Time Market operated by ISO
  - Ancillary Services Market: regulation and reserve operated by ISO
  - Installed Capacity Market operated by ISO
  - Centralized dispatch, prices vary by node; however, overlying hubs and zones are offered to reduce number of pricing point.
- Congestion management
  - Locational Marginal Pricing
  - Offer Financial Transmission Right (FTR) to allow consumers manage congestion risk

PJM Ancillary Services Markets: Regulation and Reserve

- Regulation: day ahead
  - Fine-tuning generation
  - Automatic generation control (independent of economic dispatch)
  - Response to demand within 5 mins
  - Regulation Requirement: 1.1% of PJM forecast peak
  - Correct small load change to maintain system frequency
- Reserve
  - Operating Reserve: day ahead and real time
  - Spinning Reserve

PJM Regulation Market

- Bilateral contract, self-scheduling, or spot purchase
- Regulation Market Clearing Price (RMCP) each hour of next day at 10 PM. This forward floor price helps reducing oscillation from optimization result
- Real time actual assignment

Payment = Max (RMCP, Offer price + Opportunity Cost)

PJM Reserve Market

- Operating reserve
  - Separate day ahead and real time market
  - Cost included in uplift charges resulting from other uneconomic operations (eg. unit commitment constraints, reserve requirement, dispatch uncertainty)
- Spinning reserve
  - Two types of resources- Tier 1 and Tier 2
  - Assignment will be called via phone

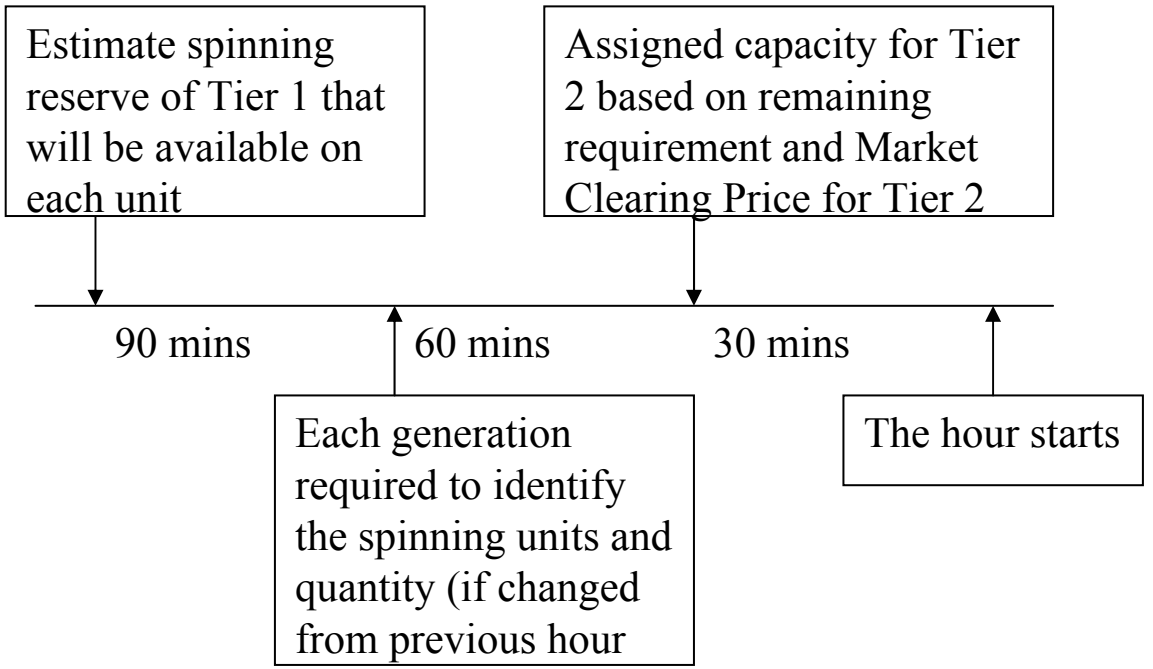
PJM Spinning Reserve: Two Types of Resources

- Tier 1: Economic units
  - Online Partially loaded units. can increase output in response to a spinning event
  - Paid by event
- Tier 2: Non-economic unites
  - Synchronized additional capacity, Condensers (CTs and Hydro), provide additional reserve not available from Tier 1
  - Capacity Payment
  - Spinning Reserve market clearing price: Auction at 6 PM one day prior to the operating day

PJM Spinning Reserve

- Requirement
  - Determine in MW, each hour of the operating day
  - 10-minute synchronized of 75% of largest contingency provided that 25% of the remaining is available on10-minute non-synchronized reserve.
  - Normally, equal to MW output of the largest unit online
- Obligation
  - Calculated based on load ratio share of the spinning requirement
  - Fulfilled by self-scheduling, bilateral trading, purchase from spinning market

PJM Reserve Market Timeline



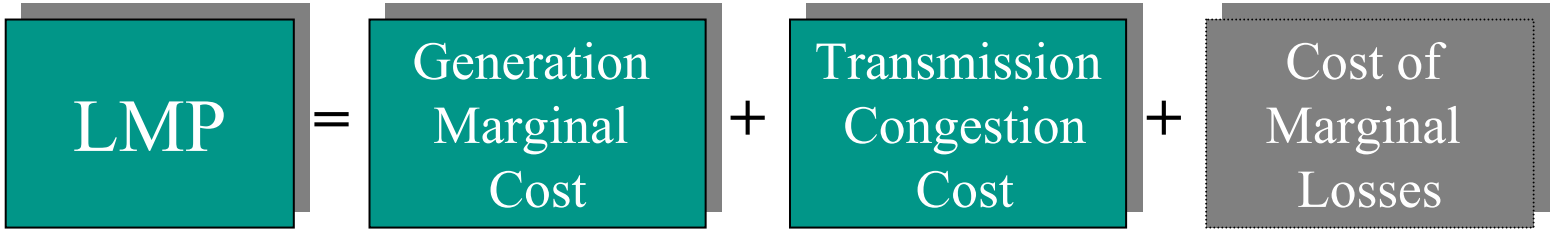
PJM Installed Capacity (ICAP) Market

- Daily and monthly market
- To ensure long term generation adequacy and short term availability (to reduce market power by generation)
- Generations compensated from selling ICAP service (a call on energy during shortage period)
- ICAP also have obligations to:
  - Submit offer to day ahead market
  - Available to PJM if not sold outside or on forced outage
  - Energy can be sold outside PJM but is subject to recall under capacity emergency conditions

PJM Congestion Management

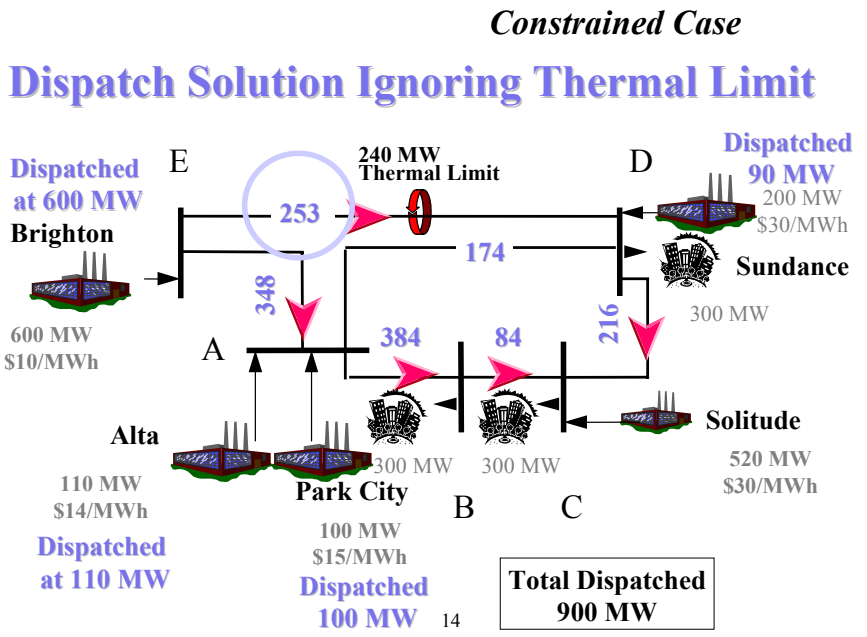
- Locational Marginal Pricing, least expensive way to serve load when congestion occurs.
- Basically, it is security-constrained economic dispatch.
- Definition:

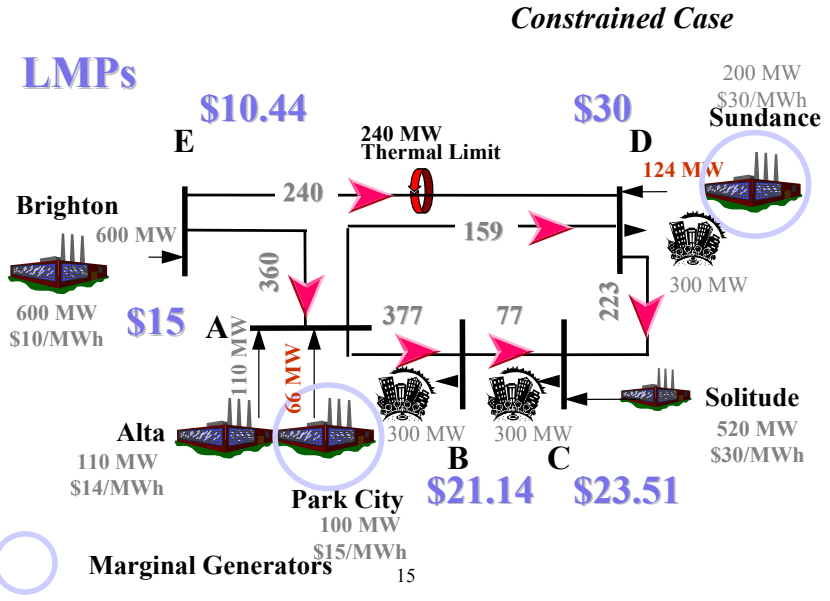
  Cost of supplying next MW of load at a specific location , considering generation marginal cost, cost of transmission congestion, and losses. (Loss cost is currently not implemented.)



PJM Transmission Congestion Cost

- Calculated based on Generation offered data and Actual flow in the system





PJM Financial Transmission Right

- Definition
  A financial contract that entitles holder to a stream of revenues (or charges) based on the hourly energy price differences across the path
- Characteristic
  - Point to point (single or aggregated; hubs or zones)
  - MW unit
  - Financial title, not physical right
  - Obtained from auction, bilateral contract
- Usefulness
  - Protect customer from increased cost due to transmission congestion
  - Give way to manage risk for forward market

NEW ENGLAND (NE)

New England (NE)

- Market structure
  - Most of utilities still vertically integrated
- Market design
  - Day Ahead Market operated by NE-ISO
  - Real Time Market operated by NE-ISO
  - Ancillary Services Market: Regulation, Reserve and Unforced Capacity Market (or Installed Capacity as in PJM) operated by NE-ISO
  - Centralized dispatch, prices vary by node; however, overlying hubs and zones are offered to reduce number of pricing point.
  - Offer virtual bidding
- Congestion management
  - Locational Marginal Pricing
  - Offer Financial Transmission Right to allow consumers manage congestion risk

NE Ancillary Services Market

- Operating reserve: maintain uninterrupted service caused by transmission or generation outages in real time
- Regulation: maintain system frequency due to load change
- Unforced capacity: payment to generators to provide incentive to build adequate generating capacity

NE Operating Reserve Market

- Day ahead and real time market
- Requirement based on the demand forecast of the following operating day
- Compensations cover generations' submitted cost including start-up, no-load costs, and opportunity costs
- Day ahead market charges to customers proportionate to their day ahead demand
- Real time market charges to customers whose load deviate from day ahead schedule or generation deviate from day-ahead schedule or not follow real time dispatch instruction

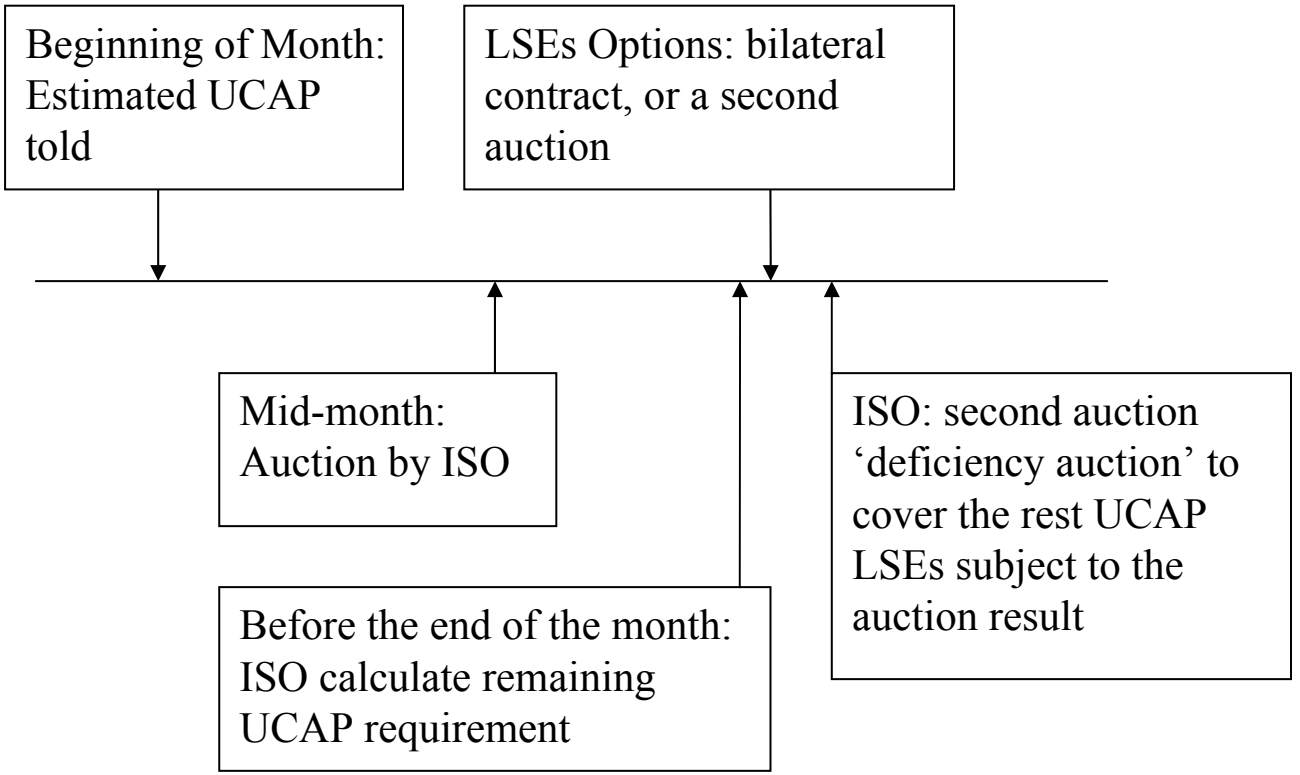
NE Regulation Market

- Day ahead market
- Generators submit offers
- ISO set hourly clearing price based on generators' offer and give dispatch instruction to a set of selected generators
- The selected generators may provide regulation by self-schedule, bilateral transactions or purchasing from the market
- Generators with dispatch instruction paid based on real-time load obligation

NE Unforced Capacity (UCAP) Market

- Monthly market
- Generators compensated for ‘sitting units’ based on ‘Unforced Capacity’ or UCAP (net capacity – forced outages) by Load Serving Entities (responsible for serving demand)
- LSEs are responsible for procuring UCAP requirement (set by ISO-NE at the beginning of each month)
- Options for LSEs: bilateral contract, auction by ISO mid-month

NE Unforced Capacity Market Time Line



CALIFORNIA

California

CA Power Exchange

30/01/2001- Suspended trading

09/03/2001- Filed for bankruptcy protection

No longer operational

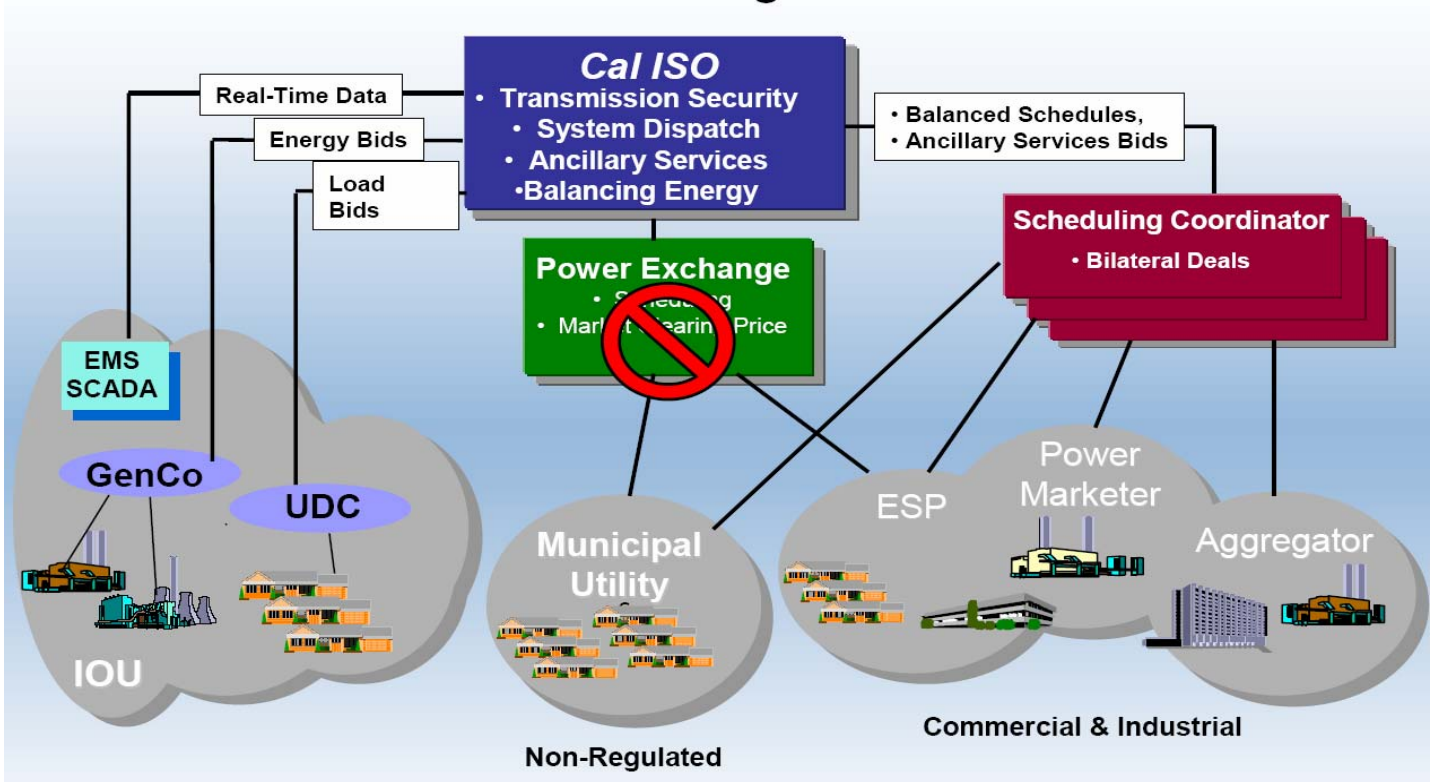
- Day-ahead Market
- Simplified model (23 zones model)
- Allow infeasible intra zone power exchange
- Might experience intra zone congestion

CAISO

- Imbalance Energy (IE) Market (or Real Time Market)
- Ancillary Service Market
- Bilateral contract: primary form of power agreement between Energy Service Provider (ESP) and electricity supplier

CAISO after CA PX filed for Bankruptcy

- Day ahead, hour ahead, and real time market



- Note:
  - EMS- Energy Management System (a computer-controlled system used by operators of electric utilities to monitor the real-time performance of the various elements of an electric system and to control generation and transmission facilities)
  - UDC- Utility Distribution Companies
  - IOU-Investor Owner Utility (a utility entity whose assets are owned by investors)
  - ESP- Electric Service Provider
  - More about Acronym at http://www.caiso.com/aboutus/glossary/#i

CAISO Imbalance Energy Market

- Real time market
- To balance actual system load
- Supplier submit offer, paid Market Clearing Price, same concept as PJM and NE
- 10 Mins before operating hour

CAISO Ancillary Services Market

- Day ahead and hour ahead market
- Operating reserve: spinning and non-spinning
- Regulating reserve
- Replacement reserve
- No Installed Capacity Market (ICAP) or Unforced Capacity Market (UCAP), as of now

CAISO Ancillary Day ahead Market

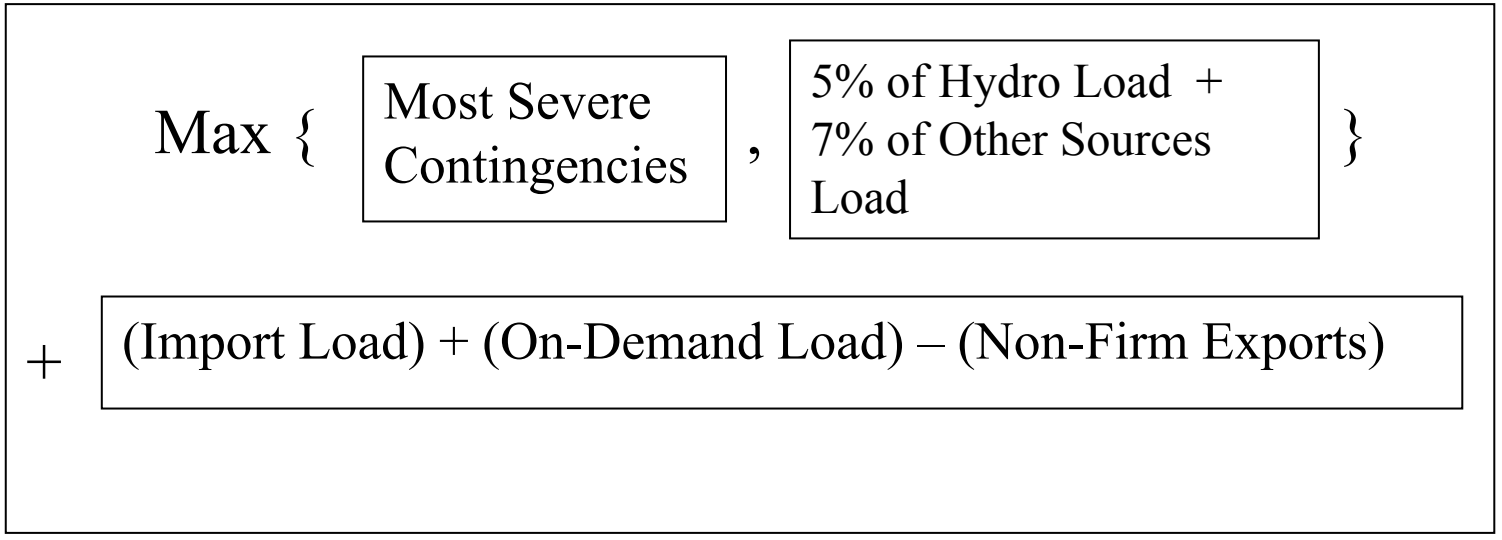
- CAISO publish an hourly forecast of ancillary service 6 PM , two days ahead of trading day
- Preferred market procurement and market clearing prices are posted on OASIS (Open Access Same Time Information System)
- Determine amount deterred to hour ahead market
- Check for congestion in preferred market. If congestion exists, open Revised Preferred Market
- Final procured ancillary service posted on OASIS

CAISO Reserve Service Description

- Regulation
  - "Generator's equipment that provides regulation service direct control by ISO to increase or reduce power."
- Spinning reserve
  - "A quantity of unloaded capacity synchronized to the grid that will ramp up in 10 minutes."
- Non-Spinning reserve
  - "A quantity of capacity that is not synchronized to the grid but can ramp up in 10 minutes."
- Replacement reserve
  - "A quantity of capacity that will ramp up within 60 minutes."

CAISO Operating Reserve

- Standard by North American Electric Reliability Council, Western Electricity Coordinating Council, and CAISO
- Reserve calculated from



CAISO Operating Reserve (cont.)

- Minimum of 50% of reserve will be spinning reserve
- Requirement: hourly basis adjustment based on CAISO judgment
- Limited maximum of 50% of reserve from outside CAISO control area sources

CAISO Regulation Reserve

- Adjusted daily or hourly by the operator
- 350 MW base (starting point) in day ahead market to ensure adequate response to frequency deviations but maybe adjusted for system conditions
- Also taken into account for actual regulation calculated in each hour of previous 7 days. Use the average of this amount as a benchmark

Note that with self-correcting method, more/less regulation will suggest the value used in the future.

CAISO Replacement Reserve

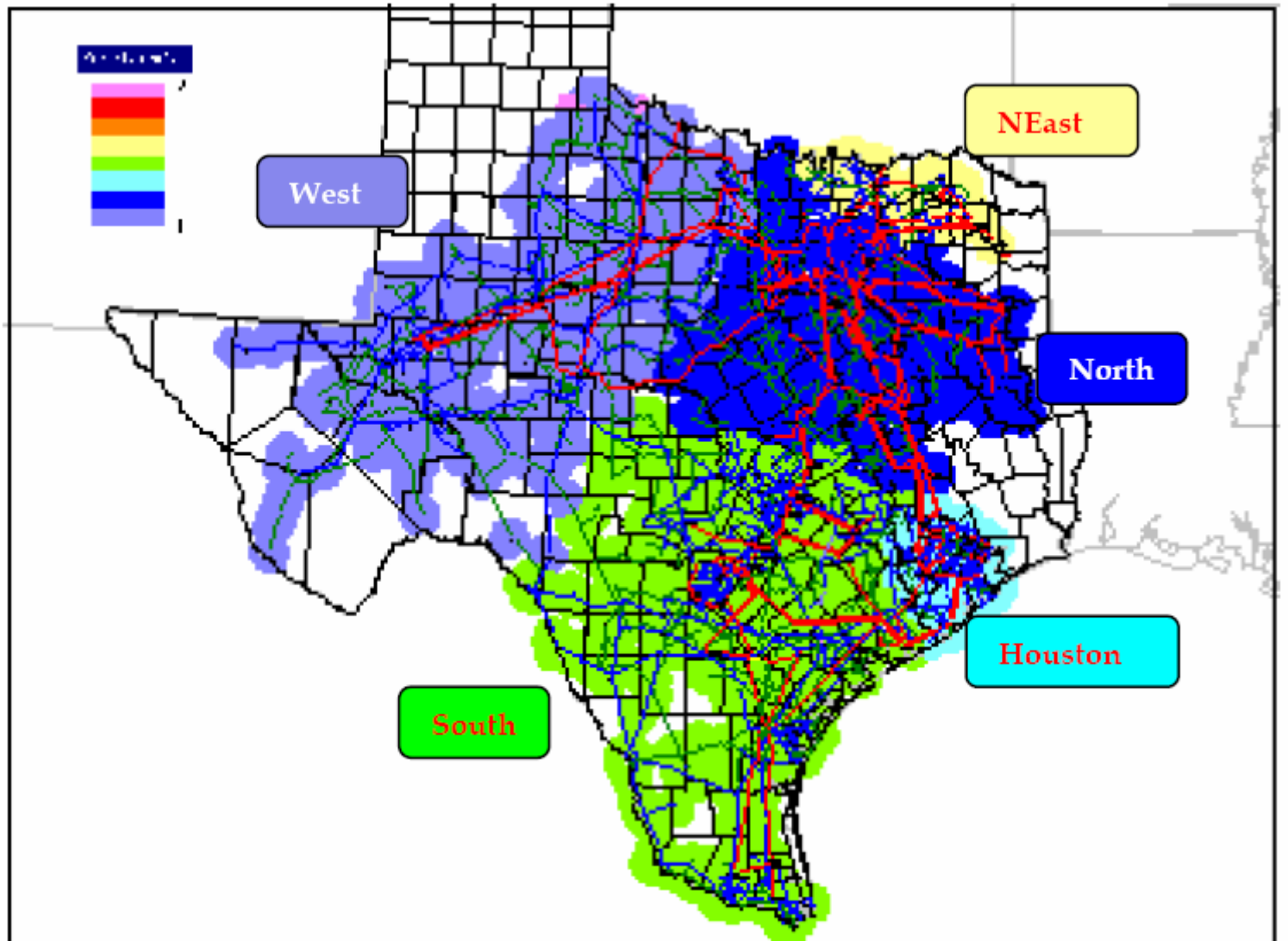
- Requirement: operator discretion based on the analysis of
  - Patterns of unplanned generation outages
  - Patterns of transmission outage
  - Seasonal variation
  - Others: factors that influencing reliability constraint
- May procure 100% of total replacement reserve from outside of CAISO

TEXAS

ERCOT

- Market structure
  - All utilities were required to unbundle their generation, transmission, distribution, and retail function.
- Market design
  - Bilateral Contract: 95-97% of total demand
  - Real Time Balancing Market
  - Zonal dispatch, prices vary by zone. ERCOT is responsible to manage zonal congestion.
  - Ancillary service market, regulation and reserve
- Congestion management
  - Zonal congestion management
  - Offer Transmission Congestion Rights (TCR) (same concept as Financial Transmission Rights) from monthly and annual auction.

ERCOT Current Market Zones



ERCOT Special Characteristic

- DC connection to neighboring area
- Serves approximately 85% of Texas load
- Covers almost 75% of land area in Texas
  - Since ERCOT is located completely in Texas, the Texas Public Utility Commission has legal power over it without any interference by Federal Energy Regulatory Commission.
  - ERCOT is more flexible in designing its own market structure.

ERCOT Energy Market Timeline

- May 1999
  - The Texas Legislature passed a bill to allow retail access.
- July 2001
  - Real time balancing market and day ahead ancillary services market are first in operation.
- January 2002
  - Retail competition began.
- February 2002
  - Began auctioning monthly and annual Transmission Congestion Rights.

ERCOT Energy Market

- Bilateral contract
  - Private agreement between sellers and buyers
  - Prices are not known by ERCOT
  - Submit to ERCOT on daily basis
  - Amount to 95-97 % of total demand
- Real time balancing market
  - Procured energy difference between total electricity requirement and energy scheduled from bilateral contract
  - Only 3-5% will be auctioned from balancing (real time) Energy Market by ERCOT.
  - Accept firms' bid function in ascending order and adjust MCP every 15 minutes

ERCOT Ancillary Services Market

- Four types of reserve
  - Regulation reserve
  - Responsive reserve
  - Non-spinning reserve
  - Replacement reserve
- Procure from auction all each day on hourly basis for the next operating day except replacement reserve
- Replacement reserve will be procured to ensure sufficient capacity when ERCOT analysis identifies capacity inadequacy or congestion

ERCOT Reserve Requirement

- Regulation reserve
  - Calculate from regulation of previous month and the same month of last year
- Responsive reserve
  - 2300 MW (summation of the two largest unit connected to ERCOT grid) all hours under normal operation
- Non-spinning reserve
  - Depend on weather condition, forecasting load.
- Replacement reserve
  - Depend on the projected congestion or capacity inadequacy

ERCOT Congestion Management

- Occurs from zonal dispatch
- Inter-zone congestion management
- Prices vary by zone
- Replacement reserve will be procured at MCP
- Basically, economic dispatch
- Zone congestion costs are allocated by some formula such that the load, with greatest impact on constraint, pay the most

ERCOT Transmission Congestion Rights (TCR)

- Financial contract
- Enable customer to hedge against risk from congestion in the future
- Acquired from auction
- 60% from annual auction
- 40% from monthly auction

MARKET FAILURES

Electric Market Challenges

- Inelastic demand
  - Consumer can not response to price change in real time
- Market power* by generation companies
  - Withholding generations to increase market clearing price
  - Excuses of maintenance, units down ,…

*Market power = Firm reduces output or raise their bid prices in order to change the market prices.

Market Rules

- Price cap
  - Generations couldn't bid more than a certain price (usually $1000/MWh)
- Constrained bid function
  - Generations could not bid X% above its history record, etc.

Electric Market Failures: Reliability Issues

- Capacity adequacy
- Reliability requirement/measurement
- Reliability cost
- Tools and operators failure
  - Lack of adequate tools to visualize system conditions
  - Lack of long distance communication tools to detect and identify system failure in short time

Capacity Adequacy

- Capacity additions may not match demand growth
- May be caused by
  - Poor market design which does not give incentive to invest in generation
  - No requirement on the system of how much installed generation should be
  - No single entity which is responsible for this obligation
  - Less capacity in the system means that generation can exhibit more market power

Reliability Requirements

- Both short term and long term
- Current Standards derive from vertically integrated market:
  - Expected energy not supplied
  - Standard reserve margin
  - System loss of load probability or expectation
- These standards consider system as a whole not individual load serving entities.
- Should percent reserve be a function of the reliability of generating units in the energy market?

Reliability Requirements –cont.

- ISO is generally charged with maintaining these standards in operation
- Since they need to buy power from real time market to maintain reliability, it could be expensive
- Do these standards serve deregulated market adequately?
- Should the consumer enjoy reliability commensurate with his willingness to pay?
- Also, we need some index to access reliability cost

Reliability Cost

- How much should we charge for reliability? And who is responsible for it? Generators or consumers?
- Should we consider unit's performance when calculating reliability cost? Should the unit with lower forced outage rate (highly reliable) get paid for reserve more than unit with higher outage rates? (Hirst and Kirby 1999)
- Chuang 2004 proposed 'Beta' factor to establish reliability measurement. Beta factor is real time energy procurement expressed as a percentage of total energy procurement. Her study reveal a strong correlation between beta and high electricity cost during summer 2000 in CA.

Tools and Operators Failure

- Recent blackout results from lack of coordination between control areas
- Communication tools, system protection tools not function optimally
- Personal, operators not well trained
- Lack of adequate tools to visualize system conditions

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