An Overview Of Electricity Restructuring and Regulation in the United States

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Overview

- What is electricity restructuring?
- Why restructure the electric industry?
- Organization of regulatory institutions.
- Responsibility and jurisdiction of regulatory agencies.
- Ratemaking practices for electricity and natural gas utilities.
  - State-level ratemaking
  - Municipal utility rates
  - Incentives in ratemaking
  - Federal ratemaking
Overview

• Coordination and competition among regulatory agencies.
• Restructuring Milestones
  – Legislation
  – FERC Orders
• Changes in regulatory practice
• Birth and Evolution of the restructured industry
  – Products associated with unbundling
  – Organization of markets
  – Open Access in Practice
  – Pricing and rates of services in practice
• Cases as appropriate throughout.
• Lessons, and future direction.
What is Restructuring?
What is Electricity Restructuring?

- It is allowing competition between sellers of electricity!
- **Wholesale restructuring**: Competition between generating companies or marketers to sell to load serving entities or in some places large industrial customers.
- **Retail restructuring**: Competition between suppliers (marketers, generators) to sell to end use customers.
- It is *NOT* abdicating the regulation of the wires part of the business.
  - Transmission remains regulated at the federal level by the Federal Energy Regulatory Commission (FERC).
  - Distribution remains regulated by state commissions. In Florida that falls to the Florida Public Service Commission (FPSC)
Deregulation or Restructuring?

• Some have referred to this process and policy direction as deregulation.
• In fact, large parts of the gas and electricity sectors will remain regulated!
• The wires or pipes parts of the business must continue to be regulated since there are still natural monopoly aspects to the “delivery or transportation” part of the sector.
• What is being “turned loose” to market forces is the commodity portion of the sector (power or gas), and not the bundled product.
• Despite this policy direction, it is still within the jurisdiction to reverse course if the policy runs into problems!
Why Restructure the Electricity Industry?
Why Restructure the Electric Utility Industry?

• **Political Climate**: Movement toward less government regulation. In many countries this includes privatization of the industry as well.

• **Economics:**
  1) Inefficiency of monopolies vs. “efficient” markets.
  2) Perverse incentives due to traditional cost-of-service regulation and poor legislation.
  3) Regulatory uncertainty.
  4) Large price differentials across jurisdictions or high prices.
  5) The need to update and expand facilities…use of incentives.
Examples of the Economics

• Traditional regulation and public ownership
  No incentives to keep costs down, especially capital costs since the rate of return was based upon capital assets. Hence, the move toward incentive regulation and privatization where competition has yet to take hold.

• Regulatory uncertainty
  Use prudence reviews that disallow many costs already incurred by utilities, changing regulatory regimes, and potential nationalization.
Examples of the Economics

• Prices
  1) High prices, due to inefficient regulatory mechanisms.
  2) High prices due to state ownership.
  3) Price differentials across countries or jurisdictions.

• Changing Economies of Scale
  1) The industry thought to have economies of scale and scope. Generation seen to be have fewer economies of scale.
  2) This has changed. Now can separate out generation, transmission, distribution, and retail supply (commercialization).
Examples of the Economics

• **Price differentials**
  1) Due to higher capital costs, mostly nuclear plants, in some states.
  2) Due to higher fuel costs/kWh in some states.
  3) High purchase costs for PURPA (1978) contracts.

• **Some examples of electricity prices (1996) (cents/kWh)**
  - NY: 14.04
  - MA: 11.25
  - NH: 13.44
  - PA: 9.73
  - IN: 6.77
  - IL: 10.34
  - OH: 8.6
  - KY: 5.55
  - CA: 11.33
  - OR: 5.69
  - WA: 5.03
  - UT: 6.69
  - GA: 7.66
  - NC: 8.05
  - SC: 7.5
  - TN: 5.88

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Source: United States Energy Information Administration. These are for 1998.
Incentives

- **Short Run**: Keep costs down, which under traditional regulation or state ownership there was little incentive to do. Areas such as fuel procurement, maintenance can be targets.

- **Long Run**: Efficient entry of new generation (amount and location) and incentives to keep the costs of new capacity down. This is the majority of costs associated with generation and will have the largest impact over time.
How Restructuring and Competition Have Been Sold Politically

• **Wrong sales pitch:** Under competition prices will be lower today than yesterday.
  – *Dangerous politically when this does not happen.*

• **Correct sales pitch:** Under competition prices will be lower down the road (5, 10, 15 years) than under the old regulatory/ownership regime.
  – *The problem is that this is tough to sell politically. Politician and their constituents are impatient.*

• **Why?** There will be transitional issues moving from a monopoly environment to a competitive environment.
Organization and Responsibility of Regulatory Agencies
Organizational Structure of Regulatory Authorities: Federal Level

• Congress: Promulgates the laws that gives agencies authority and provides budgets to some agencies.
  – Department of Energy (DOE)
  – Federal Energy Regulatory Commission (FERC)
  – Environmental Protection Agency (EPA)
  – Department of the Interior (DOI)
  – Power Marketing Administrations (PMAs)
  – Nuclear Regulatory Commission (NRC)
  – Department of Justice (DOJ), Federal Trade Commission (FTC) and Securities and Exchange Commission (SEC)
Organizational Structure of Regulatory Authorities: State and Local Level

• State Legislatures: Like Congress, they promulgate laws the confer authority and can provide budgets.
  – Public Service Commissions (PSCs)
  – State EPAs
  – State run power authorities…similar to federal PMAs
  – Other agencies (e.g. community affairs, siting)
• Cooperatively owned utilities (Co-ops)
• Local Governments
  – Siting and zoning
  – Franchise agreements and taxes
  – May operate a municipally owned utility

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Federal Jurisdiction: FERC

- Quasi-independent agency within DOE. Funding comes through fees charged to those it regulates.
- Has authority to regulate wholesale electricity transactions, both power and transmission. Technically these transactions are considered interstate commerce.
- Has the authority to regulate interstate gas pipeline transactions. Also provides certificates and eminent domain for the siting and construction of gas pipelines.
- Has licensing authority over hydroelectric projects.
- Has approval authority over mergers.
- Rates in transactions must be “just and reasonable” (J&R).
- Can order refunds if rates are found to not be J&R!
Federal Jurisdiction: FERC

- *Does not have authority* over siting and construction of high voltage transmission! This is left to state and local authorities.

- *It has no jurisdiction over reliability*. In fact reliability over the transmission system is voluntary!

- *Has no jurisdiction* over PMAs, state power authorities, municipal, or cooperatively run utilities!

- It appears to have no jurisdiction to punish market power except for going forward. This is a controversial item!

- It has no jurisdiction over the price of the natural gas commodity! (1989 Wellhead Decontrol Act)
Federal Jurisdiction: Other Agencies

• **DOE**
  - Has emergency authorities, a vague reliability responsibility, oversight of international deals, oversees federal PMAs.

• **EPA**
  - Environmental oversight of electricity and gas industries, especially with regard to pollution control laws at the federal level.

• **PMAs**
  - Set up to provide electricity service in some areas. Examples include Tennessee Valley Authority (TVA) and the Bonneville Power Administration (BPA). Not for Profit.
Federal Jurisdiction: Other Agencies

- **DOI**
  - Authority over land use and the flora and fauna.

- **NRC**
  - Authority over nuclear plant safety, operations, and approval.

- **DOJ and FTC**
  - Can have some say in mergers. Are able to handle market power issues in general.

- **SEC**
  - Merger approvals.
State Jurisdiction: PSCs

- Sets rates for retail electricity and gas. These rates are bundled rates for transportation, distribution, and the commodity itself.
- If the state has restructured its industry, the rates may be unbundled.
- Some PSCs have jurisdiction over “public power” entities such as municipals, co-ops, and state power authorities, but this varies by state.
- Some PSCs are responsible for reliability.
- Some PSCs have eminent domain authority, while others have it in another agency.
- Generally have approval authority over power plants and new transmission and distribution.
State Jurisdiction: Other Agencies

• State EPAs:
  – Responsible for helping EPA carry out federal standards. May have stricter state standards in some areas.

• State Power Authorities:
  – Work similar to federal PMAs. Examples include the New York Power Authority.

• Other Agencies:
  – Can range from special environmental or siting agencies as in California, to community affairs like Florida.
Local Jurisdiction

- Siting and zoning laws for new projects.
- Collect franchise fees if they are served by an investor owned utility (IOU) and taxes from service provision.
- Regulates rates if the local entity operates a municipally owned utility.
State-level Ratemaking
Ratemaking: Cost of Service

• The regime of choice in the US for setting rates is a traditional cost of service plus a regulated rate of return.

• This is true whether it is at the state-level or at the federal level, whether it is electricity or natural gas.

• The rates are set in a rate case where the regulatory agency looks at the historical costs of the assets under the utility’s control, and the expectation of the variable costs of operation to set the rates.

• Historically, this sort of ratemaking regime has led to over-building of capital intensive assets (Averch-Johnson effect)

• This tendency to inefficiently over-invest has led regulators to employ prudence reviews.

• In the case where costs may change relative to rate case assumptions, either new rate cases or the use of adjustment clauses.
Ratemaking: Rate Cases and Adjustment Clauses

- In an ideal world, when costs deviate significantly from the assumptions of the previous rate case, a new rate case is set.
- However, conducting rate cases have been found to be time consuming and very expensive.
  - 1999-2000 rate case in conjunction with the Louisville Gas & Electric – Kentucky Utilities merger. Some staff worked for over 1 year on data and analysis.
- So, in many states, it can be many years between rate cases.
  - In Florida, there had not been an electricity rate case in 16 years until last year. Rates settled by negotiation.
- In place of the rate case, many state utilities use adjustment clauses as a way of dealing with cost increases and decreases.

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Ratemaking: Adjustment Clauses

• Fuel Adjustment Clause (FAC):
  – Can adjust rates up or down depending upon how fuel prices vary. While there is no rate case, when these changes are large, they have been voted on.
  • For example, in Florida, traditional FAC adjustments went before the Commission for approval.

• Environmental Cost Recovery Clauses (ECRC):
  – These adjust rates up and down depending upon environmental expenditures. These can include pollution control equipment (capital expenditures), or for the purchase or sale of pollution permits.
Ratemaking: Adjustment Clauses

- Conservation Cost Recovery Clauses (CCC): These are costs associated with the utility’s duty to carry out demand-side management (DSM) or to fund public benefits programs such as renewable energy research and subsidizing renewable purchases.
- These clauses usually flow through to ratepayers on a dollar for dollar basis all cost increases or cost decreases. There are few exceptions to this rule in the US (see incentives in ratemaking below).
- Other expenditure recovered through these clauses include purchased power/gas costs (usually through FAC).
- These clauses have provided little incentive to keep costs down.
The Prudence Review

- This is a review of the utility’s decision after the fact either through a rate case, or through an adjustment clause hearing!
- This creates regulatory uncertainty, but is seen as an instrument to control costs under cost of service ratemaking.

- Nuclear power plants:
  - Many states disallowed some costs associated with the construction of these plants, but only put a small dent in the cost consequences on ratepayers.

- Fuel procurement:
  - The Georgia Commission recently has threatened Savannah Electric that it may disallow “excess” fuel costs because they did not prudently hedge in the gas market!

- Expenses from the Federal jurisdiction are considered to be prudently incurred almost automatically!
Municipal, Co-op, and PMA Ratemaking: An Aside

- These public power entities have slightly different objectives.
- The first objective is to provide quality service at the lowest cost.
- If the utility is a municipal, the second objective is to make "profits" or revenues for the city to keep taxes low.
- If the utility is a co-op, then any profits are returned to the customer/owners.
- PMAs seek to pay off bonds used to finance projects.
- Overall, it seems many of these entities act more "entrepreneurial and business-like" than their regulated cousins.
Ratemaking: Targeted Incentives

• The use of incentives in ratemaking are not all that common in the US energy sector. This is very much unlike the regulation of telecommunications in the US where incentives are more widely employed.
• Most of the incentives deal indirectly with rates in terms of performance standards on service quality.
  – Outage duration and frequency indices.
  – Customer service and call standards.
  – Tree trimming.
  – Restoration of power after interruption.
• It is not entirely clear how these are factored into overall rates.
Ratemaking: Targeted Incentives

• There are cases where incentives in the form of sharing mechanisms are used in conjunction with adjustment clauses.
  – SO2 pollution permits (allowances).
  – Wholesale power sales for retail rate purposes.
• There are some cases where there is sharing of profits over the regulated rate of return.
  – San Diego Gas & Electric.
• Benchmarking and price caps are being introduced by National Grid USA for electric distribution rates in conjunction with a merger case.
Examples of Targeted Incentives

- **SO2 Allowances:**
  - In Massachusetts and Connecticut the utility gets to keep 20% of the proceeds from sales. The though of purchases has not arisen due to state environmental standards.
  - Missouri, Empire District Electric it is a 50/50 split on allowance sales. The state commission did not address allowance purchases.
  - Wisconsin has a rule that allows a plus/minus 5% bandwidth on fuel costs to prevent them from buying more expensive coal to reduce emissions to free up allowances for sale.

- **Wholesale power sales for non-native load:**
  - In Florida the utility passes through 20% of profits from sales as a rebate through the FAC
  - Many other states have similar rules.
Examples: Incentives

• San Diego Gas & Electric (SDG&E):
  – 1994 plan allows the company to keep all profits up to 1% above allowed return, 75% of all returns from 1-1.5% above allowed return, and a 50/50 split for returns 1.5-3% above allowed return.
  – In 1999 this was more finely graduated and far more returns have been returned to ratepayers.

• National Grid USA:
  – For distribution recently acquired in Massachusetts, National Grid proposes being benchmarked against other distribution companies in the region, and if their performance is better than the benchmark, they receive higher returns.
Retail Bundled Rates: Customer Classes

• The traditional customer classes in the US are industrial, commercial, and residential.

• Usually industrial customers pay the lowest bundled rates.
  – Can take power at higher voltages (no need for distribution network)
  – High load factor…not as much need for peaking capacity or certain ancillary services.

• Commercial and residential rates are fairly close together in terms of rates. Usually commercial customers get lower rates.
  – Take power at lower voltages and have lower load factors imposing more costs on the system.
Ratemaking: Retail Pricing Options

• This is primarily targeted toward electricity, but could just as easily be implemented on the in natural service.
• Currently, consumers face a flat average cost of power or gas based on costs incurred.
• Unfortunately, this creates a situation where consumers at peak times are being subsidized by consumers at off-peak times.
• Time differentiated pricing and interruptible service prices can help this problem and can play an important role as the wholesale or upstream side of gas and electric sector undergo restructuring!
• Could also introduce pricing based upon different load factors.

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Real-time Pricing (RTP): Georgia Power

• This has been billed as the largest RTP program in the world.

• The program works in the following manner:
  – Consumers are only charged the real-time price for load different from their baseline load in each hour.
  – In this way consumers get the benefit of responding to real-time prices.
  – The utility gets to recover its embedded costs.
  – If they use less, they get paid the real-time price for the difference between actual load and baseline.
  – If they use more, they pay the real-time price for the difference between actual load and baseline load.
Real-time Pricing (RTP): Georgia Power

• Products offered:
  – Day-ahead firm with a 250 KW minimum
  – Hour-ahead firm or interruptible with a 5 MW minimum
• 1,650 customers, both commercial and industrial.
• Trying to avoid the need for about 850 MW of capacity.
• Does it work? YES!!
  – One day in 1999 the price spiked to $6,000/MWh…the load responded by reducing to about 150 MW below baseline, and 450 MW overall from peak use during those two hours.
• Helps those on the plan, and helps those not on the plan by reducing the utility’s overall cost.
Time of Use Pricing (TOUP): Gulf Power

- Gulf is located in the Florida Panhandle where the majority of its load is residential.
- Targeted toward residential consumers.
- Rate Structure:
  - Low 3.4 cents/kWh (27% of hours)
  - Medium 4.5 cents/kWh (53% of hours)
  - High 9.2 cents/kWh (19% of hours)
  - Critical 29 cents/kWh (1% of hours)
  - Standard residential rate is 5.6 cents/kWh
  - Fixed cost of $4.53/month
  - Hours of the day for each rate vary by season.
- Programmable thermostat that sends information back to the utility. Customers can program it to fit their needs by price, time of day, and specific appliances.
Time of Use Pricing (TOUP): Gulf Power

- So far the program has worked well.
  - Low price consumption up 11.75%
  - Medium price consumption down 4.9%
  - High price consumption down 21.9%
  - Critical price consumption down 41.7%
- This type of program has the same benefits as the RTP program.
- Technically, more difficult to implement, but this seems to have been overcome in large part.
Federal Ratemaking

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Federal Ratemaking: Electricity

• Energy:
  – For “cost-based rates” for wholesale sales, FERC requires utilities file a cost justification that FERC can either accept or change if the costs seem to be inflated. The rates are embedded costs plus 10%.
  – Utilities could also sell power at market-based rates if they file with FERC showing they do not have market power. This market power screen has some problems! It only looks at market concentration in general.

• Transmission Access Charges:
  – This is a traditional cost-of-service rate based on the capital cost of transmission plus any other costs associated with providing transmission (e.g. ancillary services)
  – Since Order 888 some of these costs are unbundled (charged separately).
  – The provider of transmission may, at its discretion, offer service at discounts in order to better utilize its facilities.
Federal Ratemaking: Electricity

• Interconnection:
  – Any party wishing to interconnect with a provider’s system must pay for the entire interconnection.
  – For extreme reliability problems, the interconnecting party may have to pay for upgrades to the system, although this is rare.
  – In general, the interconnecting party need not pay for upgrades. This is the current precedent. (e.g. Tennessee Utilities in 1998 and ISO-NE in 1998).

• Expansion:
  – Highly contentious for ratemaking. To “roll-in” expansion costs or not?
  – The amount of the expansion costs allocated to existing customers is determined by the benefits they receive from the expansion.
  – Determined on a case-by-case basis, or by negotiation between the parties.
  – New “participant pays” idea that puts the entire cost of expansion on those “causing” the need for expansion.
Federal Ratemaking: Natural Gas

• Pipeline transportation rates are set similarly to electric transmission rates (embedded costs plus rate of return), but have evolved a bit further.

• Two separate charges for transportation:
  – Reservation charges to help recover capital costs and a rate of return.
  – Variable charges (on a per unit basis) for the actual movement of gas.

• Prior to Order 636 in 1992, FERC used an MFV (mixed-fixed-variable) methodology.
  – Reservation charge did not include all capital costs. Part of capital costs were picked up in the variable charge. The percentages varied on a case-by-case basis.
Federal Ratemaking: Natural Gas

• Since Order 636 in 1992, a SFV (straight-fixed-variable) methodology is used.
  – All capital costs and return are recovered through the reservation charge.
  – Variable charge is just cost of actually moving the gas.
  – SFV should is a more efficient pricing methodology and should lead to better utilization of capacity.

• The reservation charges are computed based upon the number of subscribers in a “rate case”.

• Discounts from the maximum reservation charge are allowed.
  – The discounts are becoming more frequent to more fully subscribe and utilize the pipeline capacity.

• Interconnection and expansion are handled as they are in electricity. Usually a need determination process as well.
Federal Ratemaking: Incentives

- Incentive regulation or performance-based regulation (PBR) as such are not really included in the Federal tool box.
- There have been conversations within FERC regarding the use of PBR for newly forming regional transmission organizations (RTOs), but nothing has really occurred...in 5 years of discussion!
- Incentives remain limited to “market-based rates” and discounts.
- There are possibilities for “merchant transmission” in electric and “optional certificates” for pipelines and new rates schemes.
  - TransEnergie project in Long Island Sound...market transmission rates.
  - Optional certificates allow a pipeline to build while accepting more risk of recovery for costs.
  - Congestion pricing of transmission in addition to access charges.

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Regulatory Coordination and Rivalry
Regulatory Coordination

- It is aligning the regulatory, legal, and legislative practices and goals of all government bodies that affect the electric power industry.

- Examples:
  - **State vs. Federal:** This is the state PSCs and FERC moving toward the same goal.
  - **Legislative vs. Regulators:** The lawmakers enacting laws that coincide with regulatory goals.
  - **State vs. Local:** For example, local siting and zoning matching the interests of the state or federal policies.
  - **Economic vs. Environmental:** PSC or FERC regulatory goals matching up with the environmental goals of EPA and the state EPA’s.
Regulatory Rivalry: Who’s Goal Is More Important?

• FERC vs. EPA and states:
  – FERC wants lots of supply to help bolster competition in power markets which it hopes will bring down prices.
  – EPA and some states want cleaner air from power plants. The EPA has ordered some plants retro-fit control equipment and has sued other companies who have allegedly violated standards.
  – **Problem:** Both admirable goals, but the EPA action jeopardizes the FERC goal. It will take years to reach each goal.

• FERC or PSCs vs. State EPAs (and other agencies):
  – FERC and PSCs would like more transmission lines sited and built.
  – EPAs, other agencies serving other constituencies are blocking these projects.
  – **Same problem as above.**
  – Also similar to the power plant siting problem.
Regulatory Rivalry: Who has Jurisdiction?

• FERC and Florida PSC vs. Florida Legislature and Courts:
  – FERC wants more power plants built, to help push power markets.
  – The legislature passed a law in 1973 severely restricting power plant siting.
  – The legislature will not change the laws even though it is in Florida’s interest to do so!

• FERC vs. Florida PSC:
  – In 1996 FERC ordered open access to the transmission system.
  – The FPSC is still in litigation as part of an appeal before the US Supreme Court. FPSC believes that FERC is asserting jurisdiction where it has none.
Some Lessons

• There are many agencies at all levels with different jurisdictional responsibilities over energy utilities and they must coordinate their actions or else problems can occur. Perhaps the fewer agencies, the better?

• Traditional cost-of-service ratemaking has had problems, and perhaps it is time for the US to move toward the use of better incentives and PBRs. The incentives implemented so far seem to have worked well.

• Ratemaking is a complicated endeavor, and the movement toward the use of incentives and markets will make it more complex.
Legislative and Milestones in Electricity Restructuring

- Was passed by Congress in response to the energy crisis of the 1970s.
- Mandated that new types of generating facilities be able to interconnect with the transmission system and sell their power to utilities at “avoided costs”.
  - Referred to as qualifying facilities (QFs).
  - Included co-generation facilities.
  - Included renewable facilities and other “strange” projects.
- Administered by the states, sometime the avoided cost calculations were extremely high, especially in light of the collapse of the oil market in the 1980s
  - Many high price states have expensive, long-term QF contracts.
- Helped facilitate development of combined-cycle technology and independent power producers (IPPs).

• Designates a new type of generating facility, Exempt Wholesale Generators (EWGs) which are IPPs that sell power in an open market.
  – Facilities are exempt from the Public Utilities Holding Company Act.

• Mandates open access to transmission facilities be implemented by FERC.
Orders 888 and 889 (1996)

- **888**: Functional unbundling of transmission services.
  - Actual transmission of power across a system.
  - Separation of various services associated with transmission.
    - Scheduling and dispatch
    - Reactive power and voltage control
    - Energy Imbalance
    - Regulation and frequency response
    - Spinning Reserves
    - Non-spinning reserves
  - Transmission customers can either buy these services from the transmission provider, self-provide, or buy from another party. Customers must take scheduling and reactive power from the transmission provider.

- **888** dictates that jurisdictional utilities must offer open access to their transmission systems.
  - If utilities are not jurisdictional and take open access service, they must offer reciprocity.
Orders 888 and 889 (1996)

- 888 encourages the formation of independent system operators (ISOs).
  - To help aggregate systems under one operator and to eliminate transmission rate pancaking.
  - Articulated 11 principles that ISOs must adhere to.
    - Independence of governance and personnel (1 and 2).
    - Open access under a single transmission rate (no pancaking) (3).
    - Responsible for short-term reliability and control of operations (4,5).
    - Efficient congestion management that is market oriented (6,7).
    - Transmission and ancillary service pricing should promote efficient use and investment regarding generation, transmission, and consumption. (8)
    - Transmission system information publicly available (9).
    - Coordination with neighboring control areas (10).
    - Establish an alternative dispute resolution (ADR) process to resolve problems (11).
Orders 888 and 889 (1996)

- 889 creates Open Access Same-Time Information System (OASIS) to post information about the transmission system.
  - Posting of price information.
  - Available transmission capacity.
  - Capacity reservations.
  - Other information regarding transmission.
- OASIS is similar in scope to EBBs created for gas in Order 636.
- Capacity can be released in a manner very similar to gas transportation.
- Transmission service can be firm or non-firm and of varying lengths.
  - Except for some ISOs, service is obtained on a first come, first served basis.
Bilateral Markets

• Since 1992, and especially after 1996, trading between utilities and marketers has expanded.
• More and more generation owners have been applying for, and receiving market-based rate authority.
• The trading that is done is not through an organized spot market
• Done by phone between traders.
• Requires separately going to each transmission owner to secure transmission service to get deals done.
• The system is more cumbersome than the “organized” markets operated by ISOs.
Formation and Implementation of ISOs

• Creation of FERC approved ISOs (1997-1999):
  – California ISO (CAISO)
  – Pennsylvania-New Jersey-Maryland Interconnection (PJM)
  – ISO New England (ISO-NE)
  – New York ISO (NYISO).
  – PJM, ISO-NE, and NYISO were born out of tight power pool arrangements while California started from scratch!

• Each ISO operates ancillary service markets and real-time energy balancing markets.

• All but ISO-NE operate markets to handle congestion management.

- Encouraged the formation of regional transmission organizations (RTOs) by requiring utilities to make RTO filings or explain why they are not joining an RTO.
- Laid out specific characteristics and functions that an RTO must satisfy.
- While many filing have taken place in response, little has emerged and RTOs still have very different looks.
- 4 characteristics
  - Independence from market players
  - Proper regional scope and size
  - Must have operational authority over transmission
  - Responsible for short-term reliability

- 8 functions
  - Sole tariff administrator
  - Market mechanisms for congestion management
  - Handle parallel path flows
  - Provider of last resort for ancillary services
  - Sole OASIS operator and determination of transmission capability
  - Market monitoring
  - Planning and expansion
  - Inter-regional coordination

- Throughout the order the underlying theme is the use of market mechanisms both facilitation and implementation.
- Forming an RTO is purely voluntary and recall, this is only for jurisdictional utilities!
Standard Market Design (SMD)

- In many ways this is an extension of Order 2000 in that the market design would be the same across different markets.
  - Markets would dictate the use of locational marginal pricing (LMP)…nodal pricing.
  - Consequently, there must be markets for financial transmission rights.
  - Must have a real-time balancing market.
  - Ideally would have capacity markets for reliability.
  - Markets for ancillary services.
  - Looks a lot like the NYISO and PJM markets.
  - Would help coordinate markets and reliability among regions.

- This initiative is meeting resistance from states in the South and West.
  - Proposal in Congress to delay implementing SMD until 2007.
Policy Issues In Electricity Restructuring
Restructuring and RTO Development

- The experiences of ISOs in California, New York (early days), and New England (early days) have not lived up to expectations.
- Worries that power will move from low cost states to high cost states, harming consumers in low cost areas.
- Bilateral markets have not been immune from problems:
  - WSCC since Summer 2000.
  - Midwest and Southeast price spikes in the summers of 1998 and 1999, but rarely since then.
  - Transmission system was not built to handle the volume and types of transactions.
- Are the problems due to moving too fast? To slow?
- Can the problems be solved quickly?
Restructuring and RTO Development

- Poor understanding of the transmission system by policy makers! The system was not built to handle the volume of transactions that are occurring. We need more transmission.
- Poor understanding of the role of market design and the influence of other factors and markets. (e.g. price responsive demand and fuel markets)
- Regulatory uncertainty and failure (e.g. State vs. Federal or allowed return on transmission)
- Impact of other regulations on the viability of markets (e.g. environmental and siting).
- The coordination of wholesale restructuring and retail restructuring? How is this to be done?
Retail Restructuring

• 23 states have decided to go to retail competition. The states are at various stages of implementation.

• These programs usually have the following characteristics:
  – Retail rate reduction and freeze for the incumbent load serving utility. This is the price to beat.
  – Gradual implementation with large consumers going first.
  – Prices offered are flat rates and do not respond to changes in the wholesale market.

• Most programs that have been implemented to date have seen few people switch suppliers.
  – The “price to beat” has been set quite low, sometimes lower than the wholesale price of power.
  – There are problems for the incumbent utility as the supplier of last resort and how they plan for this.
  – Many retail marketers have scaled back their operations.
  – Pennsylvania has been the most successful to date.
State vs. Federal Jurisdiction

• Most states feel as if FERC’s initiative under Order 2000 will strip them of much of their regulatory authority.
  – No doubt about the regulation of high voltage transmission
  – Formerly regulated generators become EWGs

• Most states feeling adverse impacts believe FERC is unresponsive to their concerns and will not help.
  – No refunds ordered until just recently, and even then with caveats.
  – States such as California believe that market power is a big problem, yet only FERC, DOJ, or FTC has the authority to deal with this

• Transmission siting and eminent domain
  – Unlike gas pipelines, FERC has not eminent domain authority in transmission siting
  – States could threaten use if they do not like what is happening (CA)
Environmental and Siting Concerns for Generation

• One big question is whether new plants can be sited
  – NIMBY is alive and well.
  – Environmental concerns, despite new plants being cleaner than existing plants.
  – Land and water use issues.

• Impact of pollution permit markets such as those in California, or with wider scope such as the SO$_2$ program and the OTC NO$_x$ market.

• Current EPA lawsuit regarding NSPS for unit maintenance and upgrades.

• Poor planning and regulatory coordination of environmental programs with each other, and with electricity policy.
  – Power markets and pollution markets can work well together!
Volatility of Fuel Markets and Their Impact on Power Markets

- As restructuring plans have been made, many assumptions had been made about fuel markets...prices will remain low, supplies will be adequate.
- What has happened in with natural gas prices in the US shows the fallacy of this assumption...and it could likely be a problem elsewhere.
- The volatility creates a public perception problem in that power prices now become more volatile, and this is a change from power pricing under the old regulatory regime.
Price Performance

- California and WSCC were in the news due to high prices:
  - greater than expected demand growth, high gas prices, low water levels, greater pollution concerns, greater risk with regulatory uncertainty and failures.

- PJM, the Midwest, and the Southeast...quiet for now:
  - Predominantly coal and nuclear dominated which are the cheapest sources in terms of running costs.
  - However, in the past, these areas have experienced price spikes when stressed. Reserve margins are falling.

- NYISO and ISO-NE:
  - higher prices early on, but they have stabilized in the last two years, but rely on more expensive fuels (oil, gas) and coal plants incur greater transport costs.
  - These systems have been more easily stressed due to transmission and declining reserve margins.
Institutional/Historical Background Related to the Blackout of 14/08/03
Reliability Responsibilities Prior to ISOs

- After the Northeast Blackout of 1965, the North America Electric Reliability Council (NERC) was formed.
- Within NERC, there were several regional reliability councils that were responsible for planning in both the short-term and the long-term.
- NERC and the regional councils promulgated operational rules to ensure that the system was operated reliably.
- Rules were voluntary only and no penalties were put into place to enforce the rules.
- In fact, since all utilities were vertically integrated monopolies without competition, there was an incentive to cooperate.
- Still, there were blackouts in 1977 and 1996 in parts of the US.
Operational Responsibilities

- Within each reliability region, sub-regions were created in many places.
- Within each region, there could be several different control areas!!!
- To coordinate reliability within the control areas, one utility would have been the “security coordinator”.
- For example, in ECAR (East Central Area Reliability Council), American Electric Power would have been the security coordinator for its sub-region.
- The security coordinator had power to get dispatches changed to prevent failures.
- When problems occur, phone calls between operators were common to prevent failures.
Advent of Markets and Competition

• With the beginnings of competition (1992-1996), the high voltage transmission system was being used in ways that it had not in the past.

• High voltage transmission links between control areas, once used for reserve sharing, were being used increasingly for trading.

• Trading means flows on the system were increasing.

• Additions to transmission capacity were not keeping up with the increases in demand and the new uses of the system.
NERC Intervention

- In order to handle the volume of power flowing over interstate lines, NERC comes up with the Transmission Loading Relief (TLR) procedure.
- The TLR procedure is dependent upon power transfer distribution factors (PTDFs) to determine who is impacting a line.
- In the most serious of cases, the “security coordinator” will force “transactions” or “flows” to be cut if the impact on the line is greater than 5%.
- TLR procedures make no attempt to price congestion in the system.
- TLR are not needed to cut transactions were nodal pricing is in place (PJM, NYISO)
Advent of Markets and Competition

- Also, with competition, vertically integrated utilities had little incentive to cooperate on reliability. Afterall, they were no “competitors”.
- Also, reliability was being increasingly used to “foreclose” markets to competitors (See AEP and their N-4 Contingency criteria).
- FERC, with open access sees how reliability is being used to restrict competition and through Order 2000 and SMD tries to get utilities to put transmission into independent companies (ISOs, RTOs).
- The question becomes: Who is responsible for reliability? ISOs and RTOs? Is this advisory or operational authority?
Incentives to Jeopardize Reliability

- In July 1999, Cinergy (in Ohio) took power off of the system without paying for it by letting its ACE fall below zero.
- In the “old days” this was not a problem since there was no competition and power would be paid back in kind later.
- However, with power markets, when the price is very high, a utility can use its position as a control area to take power without paying.
- The regional reliability council (ECAR) came up with penalties for doing this after the incident, but Cinergy was never really punished for this reliability problem.
Incentives to Jeopardize Reliability

- In July 1999, PJM almost experienced a voltage collapse on its system due to low voltages in the eastern part of its system (Delaware).
- Utilities from outside PJM wanted to “wheel through” to sell power in NYISO and New England, but there was no voltage to support the flows.
- Utilities in PJM wanted to produce real power ($900/MWh) versus reactive power that was paid a “cost-of-service” price despite PJM’s orders to produce reactive power.
- Disaster was averted, but a change to the market rules was needed to price reactive power at the real power price when needed in these circumstances.
Reliability Authority of ISOs and RTOs

• FERC wants ISOs and RTOs to be responsible for reliability, and in an operational sense.
• This is true in PJM, New England, New York ISOs.
• However in the new Midwest ISO, it is advisory only! The individual control areas have operational authority and control.
• Therefore, there are different reliability as well as market protocols for the Northeast ISOs and the Midwest ISO.
• In the Midwest, where the blackout started, responsibility and control were far from clear.
Quick Summary

- FirstEnergy (near Cleveland, OH) loses about 600 MW from Eastlake 5.
- One transmission line trips moving power from southeast and east central Ohio to the Cleveland area.
- Other lines start tripping out forcing power to move through Indiana and Michigan to get to Northern Ohio.
- Southern Ohio separates from Northern Ohio.
- The flow becomes to great and collapses voltage in Michigan. Michigan is split in two.
- Power reverses flow through PJM, and New York, through Ontario and Eastern Michigan to get to Northern Ohio.
Quick Summary

• Power flows through Eastern Michigan trip out units and lines.
• PJM separates from Ohio and New York.
• New England separates from New York.
• Power reverses flow going back east through Ontario and New York tripping out the rest of the system.
Before the Blackout

- Control room transcripts from FirstEnergy show the control operators had no telemetry showing problems on the system and seemed to have no idea what was happening!
- The Midwest ISO, acting as security coordinator, informs FirstEnergy of the problem, but it has no operational authority!
- Both PJM (acting as security coordinator for AEP) and the Midwest ISO call TLRs, but few transactions were cut (scheduled flows).
- All of this was 10 minutes to 2 hours before the blackout.
- Other ISOs and areas were not aware of the total problem, especially NYISO and Ontario IMO
Questions in the Aftermath

• With all of the power flowing to the Cleveland area, why didn’t FirstEnergy shed load?

• According to some in the regulatory community, FirstEnergy was under fire for poor reliability performance in Ohio and New Jersey. Shedding load would be unthinkable!

• Perhaps it would have been too expensive to buy additional replacement power given that they were buying replacement power for Davis-Besse (750 MW). So just take power off of the system like Cinergy 1999?

• The 2003 NERC Summer Assessment pointed to the Cleveland area as highly problematic. Preparations should have been made!
Questions in the Aftermath

• Why was FirstEnergy so blind to what was happening?
• This question can only be answered in the course of the ongoing investigation.
• It seem unthinkable that there are no back-up systems to gather telemetry for control area operations.
Questions in the Aftermath

• Why didn’t the Midwest ISO have operational authority?
• This was a decision made by stakeholders for the Midwest ISO as it is still in the process of forming its markets.
• A political decision by FERC to approve this structure to signal to those in the West and South that they do not want to have “complete control”?
• A political decision by FERC to get more utilities under an ISO?

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Questions in the Aftermath

• Why did the blackout spread?
• It is clear that the reliability coordination that once existed no longer exists.
• ITC complained that it tried to find out from FirstEnergy what was happening but got no response.
• New York and Ontario were taken by surprise and had no idea what was happening until too late.
• Lack of market rule coordination that would be solved by SMD.
• Lack of transmission to handle power flows?
• Different protection settings to serve the purposes of markets/control area operators?
Questions in the Aftermath

• To prevent the spread of problems, should we not be so interconnected?
• Many groups (they don’t understand the industry) are calling for separation, not interconnection.
• Idea of self-sufficiency…but they do not understand the costs!
• It is interconnections that help reduce overall costs to consumers through trading and reserve sharing.
Possible Solutions

• **FERC should have authority over reliability.**
  – Currently reliability is voluntary and there are few, if any penalties, for violating standards.

• **More transmission must be built.**
  – The problem is FERC has no siting authority…this is left to the states, but we have an interstate transmission system.
  – More and stronger interconnections are needed…not less.

• **Operational authority of ISOs must be in place.**

• **SMD must be implemented to ease coordination.**
  – The problem is so many politicians are against this (“states rights”)
  – SMD being held up creates uncertainty that prevents reliability initiatives from moving forward and transmission from being built.
Market Designs in the Northeast: PJM and The New York ISO

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Overview

• The NYISO commenced operations on November 18, 1999 while PJM has been in operation since 1997.

• Formation of the NYISO and PJM comes out of the tight power pool structure of the NYPP and MAAC.

• Energy Markets: day-ahead and real-time

• Ancillary Service (AS) Markets: day-ahead and real-time. These markets include regulation, 10-minute spinning reserves, 10-minute non-synchronous reserves and 30-minute operating reserves.

• Pricing/Congestion Management

• Transmission Rights Market

• Installed Capacity Markets

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Design Issues

- Bidding rules and procedures
- Information requirements and availability
- Market clearing and price determination
- Commitment and dispatch of generating units
- Substitution possibilities
- Timing of markets
- Congestion management
- Financial settlement
- Other institutional arrangements
Major Issues

• Multi-part bidding
• Disclosure of bid information
• Demand-side bidding and demand elasticity
• Simultaneous market clearing
• Ancillary services substitution
• Congestion management: nodal and zonal
• Limitations on the supply of ancillary services
• No compensation for uninstructed excess generation
• Price determination and price corrections
• The potential for the exercise of market power and strategic behavior
• Commitment and dispatch of generators for reliability
Day-Ahead Markets

- Supply-side and demand-side bidding for energy
- Supply-side only bids for ancillary services
- Multi-part bidding by generators: start-up, minimum load, and energy costs
- Generators submit other technical info to the ISO
- Load Serving Entities (LSEs) submit load forecasts to ISO
- Bids can be curves or “block” bids
- No restriction on who can bid into the market.
- Bilateral schedules designating source and sink and decremental bids
- Bids must be submitted the day prior to the dispatch day.
Ancillary Service Markets

• Bidding occurs simultaneously along with energy markets.
• The same capacity can be bid into more than one market, but cannot be committed to more than one market.
• Demand is perfectly inelastic (with respect to its own price).
• Buyers can purchase from a third party or self supply.
• Some suppliers may incur start-up and minimum load costs.
• There are
  – Some restriction on who can bid into the markets.
  – Penalties for not meeting performance criteria.
  – Two types of substitution possibilities.
**Ancillary Services Markets**

- Substitution possibilities:
  - demand substitution
  - product substitution
- Demand substitution allows the ISO to procure a “more technically stringent” reserve in place of a “less technically stringent” reserve if it lowers overall bid cost of providing reserves.
- Demand substitution is only done for reserve services and does not include regulation.
- Product substitution is a by-product of clearing the markets simultaneously.
- In NYISO, ancillary services can have “locational” prices to reflect binding east-west constraints.
- In PJM, there are not as many ancillary service products opened to the market.
Congestion Management

- The NYISO and PJM use nodal congestion pricing for generator and zonal congestion pricing for loads.
- A price at a node on the grid is the marginal cost of delivering 1 more MW of energy to that node.
- The nodal price includes congestion costs and marginal losses.
- The zonal price is a weighted average of the nodal prices for a pre-defined zone.
- The NYISO has 11 internal pre-defined zones based upon 10 interfaces with potential or known congestion problems. It has also defined 4 external zones corresponding to ties with other control areas. In PJM, it is done by LSE.
**Energy Markets**
- Receive bids and technical information from generators (supply).
- Receive bids and load forecasts from load (demand).
- Receive bilateral schedules.

**Ancillary Services Markets**
- Receive bids from suppliers.
- Receive bilateral and self-supply schedules.

**Transmission System and Congestion Management**
- Thermal limits
- Voltage limits
- Feasibility of schedules
- Other information

**Evaluate Information to:**
- Commit units to run for energy and ancillary services.
- Dispatch units to energy and ancillary services.
- Commit and dispatch at lowest bid cost.
- Clear markets simultaneously.
- Commit and dispatch generators for reliability.
Day-Ahead Commitment

- Objective is to jointly minimize cost of generation and ancillary service provision subject to transmission and other constraints.
- Markets for energy and ancillary services clear simultaneously. Locational energy prices, congestion costs, marginal losses, and AS prices are computed.
- Commitment is financially binding: Generators receive a nodal price, LSEs pay a zonal price.
- Transmission constraints influence ancillary services capacity commitments.
- Bilateral schedules pay congestion and marginal losses.
- At the request of transmission owners, generators may be committed for local reliability in the NYISO. This information is posted on OASIS.
- In PJM, they recognize some generators are must-run.
Real-Time Markets

- Bids and bilateral schedules must be submitted 90 minutes before the dispatch hour.
- Bids and bilateral schedules from the day-ahead commitment may be revised, or new ones submitted.
- Generators may only revise downward their bid price for energy already committed day-ahead.
- No multi-part bidding for generators.
- LSEs can revise their bids in any manner they wish.
- 90-minute ahead bids are used in real-time dispatch.
Real-Time Operation

- ISO uses updated info to determine real-time schedules.
- Every 5 minutes the ISO runs a security constrained dispatch (SCD) which minimizes total energy bid costs subject to constraints.
- SCD yields prices, congestion costs, and marginal losses at every 5 minutes during the dispatch hour.
- Deviations from the day-ahead schedule are priced at the 5 minute prices.
- Generators are not paid for over generation.
- Bilateral schedule deviations pay for real-time congestion and marginal losses.
- Ancillary services prices are determined separately from the energy price.
- Generators may be dispatched out of merit order at the request of transmission owners for local reliability.
Financial Settlement: Day-Ahead

Generators receive:
- \((\text{day-ahead price}) \times (\text{day-ahead scheduled injection})\)
- May also receive an uplift payment due to start-up and min load costs.

LSEs pay:
- \((\text{day-ahead price}) \times (\text{day-ahead scheduled withdrawal})\)

Bilateral Customers:
- Pay congestion costs and marginal losses based on the day-ahead schedule.
Financial Settlement: Real-Time

Generators receive:
- Difference between day-ahead scheduled injection and actual real-time injections at the real-time price.
- Any injections above those directed by the ISO do not receive payments.

LSEs pay:
- Difference between day-ahead scheduled withdrawals and actual real-time withdrawals at the real-time price.

Bilateral Transactions scheduled after the day-ahead market:
- Pay congestion costs and marginal losses based upon real-time dispatch.
Transmission Markets: TCCs and FTRs

• A TCC/FTR gives the holder the right to collect congestion rents based upon a point of injection and point of withdrawal.
• A TCC/FTR gives the holder a hedge against congestion costs.
• TCCs/FTRs are initially allocated based on existing transmission agreements.
• Any transmission capacity remaining after the initial allocation of TCCs/FTRs is auctioned or sold through bilateral sales on the ISOs OASIS.
TCC/FTR Auction

• TCCs/FTRs to be auctioned cover periods from 6 months to 5 years in length
• TCCs delineated by peak time (7am-11pm) and off-peak time (11pm-7am).

NYISO auction
• 2 Stages, each stage has multiple rounds.
• Before Stage 1 amounts and paths of TCCs offered up for sale announced.
• Ex-ante no predetermined set of TCCs due to nature of the network.
• Information on ATC, historical congestion, and other technical data are available to participants.
TCC Auction

- Objective is to maximize the value of TCCs awarded to bidders.
- Bids include: 1) number of TCCs in MW 2) $/MW 3) POI, POW 4) duration
- ISO runs a security constrained power flow to determine feasibility of bids.
- Stage 1 has 4 rounds, each round is financially binding.
- Only a fraction of TCCs are awarded in each round.
- Market clearing price is the lowest winning bid for a particular TCC, or a TCC that has the equivalent impact on flows.

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TCC/FTR Auction: Issues

1) Is strategic behavior possible?
   Our initial analysis would indicate it is not likely, though PJM has discovered some potential manipulation.

2) Will the auction mechanism aid in price discovery?
   The iterative process of the auction and each bid being financially binding should do the trick.

3) Monthly Reconfiguration Auction in NYISO
   The initial proposal did not include this. The compliance filing has added this feature.
TCC Auction: Issues

4) Will secondary markets arise?
   FERC has directed the NYISO to make ownership and other info on TCCs/FTRs publicly available. We have also directed the ISO to contemplate a process for reconfiguring TCCs/FTRs that may be sold bilaterally.

5) Timing of the Auction
   How far in advance of the time TCCs become useful should it occur.
Installed Capacity Market

- The NYISO and PJM run an installed capacity market,
- Installed capacity is a holdover from regional reliability rules. Its existence is based upon reliability needs.
- A load serving entity’s installed capacity requirement means it must hold or be contractually entitled to \((100 + X)\%\) of its peak load in generating capacity.
- Installed capacity can be obtained from outside the control area.
- Penalties exist for not meeting the requirements.
- PJM has had generators pay the penalty to serve load outside of its area.
Market Performance

- The day-ahead markets:
  - have been run with few problems.
  - have seen no need for price “corrections”.
  - have witnessed some instances of “abnormally high” prices.

- The hour-ahead ancillary service markets:
  - have not had any price corrections, but there have been prices as high as $9998/MWh in some hours.

- The real-time energy market:
  - has seen the need for price corrections in the NYISO on a fairly regular basis.
  - has seen some prices in excess of $1000/MWh in NYISO, but prices are capped at $1000/MWh in PJM.
  - The NYISO continues to work on the problems.

- Commitments and dispatch for local reliability have occurred. Generally done in NYC and Long Island.
Market Performance

• The substitution of “more stringent” reserves for “less stringent” reserves has increased with time.

• The markets have also witnessed increasing instances of “price inversions” with time.

• Perhaps generation have found a way to strategically bid into the ancillary services markets.

• Congestion is daily event at some point during the day in both PJM and NYISO (west to east)

• Impact of multi-part bidding is not yet known.
Price Corrections in NYISO

- No corrections have been necessary in the day-ahead energy markets or in the ancillary services markets.
- Frequent corrections have been made in the real-time energy market due to software problems.
  - Incorrect reading of data
  - “Very” flat or steep bid curves
  - Problems in handling gas turbines
California Market Design on Paper and In Practice
California Power Exchange

- AB 1890 forced the incumbent IOUs to do all power purchases through the CalPX until their stranded costs were paid off, or until March 31, 2002.
- For all other entities participation was voluntary.
- The CalPX is a completely separate entity from the CAISO.
  - It was believed that if the CAISO conducted the market, it would have a stake in the market. Moreover, the CAISO mission was to operate the transmission system.
California Power Exchange

• Originally the PX offered markets for day-ahead energy and hour-ahead energy.
  – Later the hour-ahead energy market disappeared in favor of a “day-of” market where hourly schedules after the day-ahead market were done three times a day (8 hour blocks) due to low volumes.

• Load and generation bid into the CalPX specifying schedules of quantities and prices only. (also called “one part bids”)
  – Neither generation or load specified exact sources…just aggregate quantities. These are known as portfolio bids.

• Given supply and demand bids, the CalPX would clear the market. (Equilibrium price and quantity)
California ISO

• The CAISO was responsible for operation of the transmission system and associated Order 888 ancillary services.

• The products offered in markets were:
  – Real-time balancing energy
    • Also known as the real-time energy market.
  – Regulation (up and down) (day-ahead and real-time)
    • This service was often used for load following purposes.
  – 10 minute Spinning Reserves (day-ahead and real-time)
  – 30 minute Non-spinning Reserves (day-ahead and real-time)
  – 60 minute Replacement Reserves (day-ahead and real-time)
California ISO

- The bids for energy were price and quantity schedules.
- The bids for the other ancillary services were capacity only bids (for evaluation), with energy bids to be used in case of dispatch.
- The ISO cleared each of the markets it operates separately from the others. Moreover, it cleared these markets in sequence.
  - Real-time energy, then
  - Regulation (up and down), then
  - 10 Minute Spinning Reserves, then
  - 30 Minute Non-spinning Reserves, then finally
  - 60 Minute Replacement Reserves.
- The market clearing price was the highest accepted bid.
- Demand in these markets was perfectly inelastic (no price responsiveness!).
California ISO

- Additionally, it is the ISO’s job to schedule and dispatch units subject to the limitations of the transmission system. This also includes provision of voltage support and reactive power.

- As a part of the scheduling function, the ISO had at its disposal reliability-must-run (RMR) units.
  - These are units designated by the ISO as crucial to system reliability and security. RMR units are run either for voltage support or for congestion relief.

- RMR units could either bid into the CalPX, or they could wait to be dispatched by the ISO.
  - RMR units received a fixed capacity payment, plus a payment for operating when called upon. This operating payment was quite generous!
California ISO

• Finally, the ISO also operates a congestion management market in real-time. Units are re-dispatched based upon “adjustment bids”

• Congestion pricing is by zones. Originally two zones (NP 15, SP 15). It was felt that the amount of congestion within the zones was not worth worrying about.

• At the start of market operations, the markets for transmission rights were not fully developed, though the idea was to have financial rights with a scheduling priority.
Making the Day-Ahead Market Work
On Paper: CalPX and the CAISO

• In the CalPX, once the market clearing prices and quantities are determined, those that had bids accepted turn in schedules to the CalPX (what sources will be generating and how much).

• The schedules are forwarded to the CAISO to ensure they are feasible. If they are not physically feasible (do not violate system constraints), the CAISO send the schedules back to the CalPX to be re-done.

• This iterative process is to continue until the schedules are feasible.
Making the Day-Ahead Market Work
In Practice: CalPX and the CAISO

- The CAISO sends the schedules back to the CalPX, but the CalPX simply send the same schedule back and forces the CAISO to deal with constraints in real-time.
- This forces the CAISO to use RMR units and use adjustment bids more than it might like!
- Market design problems led to occasional price spikes in various markets, and some strange pricing patterns.
The hope is that the price utilities pay for power will be far less than the market price from the PX.
Price Cap Regulation California Style

- Retail rate freeze until stranded costs were paid off of about 6.5 cents/kWh.
  - Most rudimentary form of price cap regulation. It is set up as if $RPI = X$ each year so that the price does not rise.
  - Certainly, it seems the incumbent, load serving entities would have the incentive to cut costs to maximize shareholder value.
  - Utilities now bear all of the risk.
  - No provisions made for “unexpected events”.
Market Design Problems
Discovered…Hint: Some Are Easy to Find
Ancillary Services Markets

• There are too many to list, but the major ones are
  – Separate, sequential clearing of the markets.
  – Not all suppliers had market based rate authority.
  – Perfectly inelastic demand.
  – Purchasing practices based upon location not transparent.
  – Imports from outside the CAISO excluded.
  – Unexpectedly high demand for regulation.

• And these were written about by the CAISO’s Market Surveillance Committee (MSC) in August 1998!

• In July of 1998, price spikes in these markets of $9,999!
RMR Contracts

- With the generous payments to RMR units for operating, no incentive to be bid or scheduled day-ahead unless the day-ahead price was high enough!
- Essentially these units would withhold capacity from the day-ahead market (with high bids), but could be assured of getting dispatched.
Separation of the CAISO and the CalPX

• This is easy to spot. It makes congestion management difficult at best.

• It also allows generators to play games with their schedules.
  – Schedule a unit that you know will cause congestion.
  – Submit high adjustment bid to be backed down.
  – Get paid a lot for not generating!

• May not be dispatching the least-cost mix of units without a rational day-ahead unit commitment, as it has been traditionally done.
Congestion Management

- Assumptions that only zones were needed to handle congestion were erroneous.
- It was more prevalent within zones than CAISO staff wanted to admit.
- Zonal congestion management premise to control market power also erroneous.
- Continued patches to the scheme through filings at FERC.
- Many of these solutions were rejected by FERC.
One Part Bids for Energy

- With a price only bid for energy, generators would have to factor in start-up and minimum load costs into their bids.
- Consequently, many bids were higher than marginal cost.
- Other problems were that units would often be started up, and the shut down a short time later.
Attempted Solutions to the Market Design Problems

• The CAISO made attempts to correct some of these problems, but most attempts were only partial fixes and often took a while to do.
  – Ancillary services
  – RMR Contracts and dispatch
  – Addition of a new congestion zone

• Price Caps were used as a stop-gap measure by FERC as requested by the CAISO.
  – $250 cap, then $750, then back to $250.

• The cap in the ISO market created a new set of problems...
Different Caps in the CAISO and the CalPX Markets

• With the caps at $250 or $750 in the CAISO markets, there existed a $2500 cap in the CalPX market.

• For energy, this meant that loads could always go to the CAISO real-time balancing market for power.

• Loads began underscheduling in the PX market during peak periods, making it tough on the ISO to balance the system.

• ISO requested and received permission from FERC for underscheduling penalties.
Overall, Demand is Unresponsive to Prices

• While there is demand bidding in the CalPX, the reality is that there is little or no price responsiveness in demand.
• This is especially acute in the CAISO markets where demand is given as fixed.
• Ultimate end-users do not see prices fluctuating.
• No real-time or time of use pricing employed.
  – The utilities offer time of use pricing, but so few take it..
  – The are interruptible services, for which there is a flat discount.
The Wholesale Market, April 2000-Summer 2001

• Gas prices:
  – $2.32/mmBtu in March, $4.90 in May, $6.04 in Sept., $18 end of November, $60 one day in December, leveling off to between $10 and $25 in January, to $30 in February, and back down to the $10-$15 range currently.

• Northwest hydro resources drying up slowly and steadily.

• Pollution permit prices
  – go from $4/lb of Nox in march to between $35 and $45/lb June to December, coming back down to about $15/lb now.

• Significant generator outages start in April and persist for various reasons.

• Monthly loads increasing 2% to 15% versus the same months in 1999.
## The Wholesale Market, April 2000-August 2000

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<th>CAISO RT</th>
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<td>$4.90</td>
<td>$6</td>
<td>$3.16</td>
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<tr>
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<td>$126.75</td>
<td>$4.73</td>
<td>$8</td>
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<td>$114.14</td>
<td>$4.65</td>
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<td>$142</td>
<td>$175</td>
<td>$4.97</td>
<td>$46</td>
<td>$12.18</td>
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Source: California ISO

<table>
<thead>
<tr>
<th>Average Prices In $/MWh</th>
<th>CalPX DA</th>
<th>CAISO RT</th>
<th>Gas Price</th>
<th>Nox Price $/lb.</th>
<th>AS Cost</th>
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<td>Sept.</td>
<td>$104</td>
<td>$149</td>
<td>$6.04</td>
<td>$41</td>
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<td>$5.50-18 avg. $10.65</td>
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<td>$423*</td>
<td>$12-60 avg. $26</td>
<td>$42</td>
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<td>Jan.</td>
<td>$281</td>
<td>$290*</td>
<td>$10-17</td>
<td>$17</td>
<td>$12.96</td>
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* average of all real-time energy purchased including “as-bid” and out of market purchases by the ISO.

Source: California ISO

Public Utility Research Center, University of Florida
San Diego…The Fuse is Lit!

- SDG&E has its stranded costs recovered, paving the way for it to pass through wholesale market costs.
- Starting in June 2000, customers in San Diego became exposed to the volatility of the market facing the actual price for power.
- As customers start getting their bills, there is a revolt of sorts, leading the CPUC to re-institute the price cap for San Diego.
The “Unexpected Events”

• Ever increasing natural gas prices.
• Lower than normal rainfall in the west.
• Higher than expected load growth.
• Tougher than expected entry of new generation.
• Bumping up against air quality constraints.
• Recognition that the transmission system was not built for the “new market” paradigm.
• Potential market power abuses in the wholesale market.
• Market design problems discovered.
• Could these have been predicted? Some could.
• Could provisions have been made in the price cap plan to account for these? Yes!
Natural Gas and Oil Prices

• Gas prices have gone from $2.50-$3.00 to $4.50-$6.00 range until the winter heating season.
  – This could have been foreseen. Fundamentals dictated that gas prices should rise.
  – Storage levels historically low.
  – Rig counts down…why drill for gas when the price is so low?
  – Liquefied natural gas (LNG) terminals going unused.
  – OPEC flexing its muscle.
Natural Gas in California

• California gets its gas from Canada (Northern California) or from Texas/Rocky Mountain fields (Southern California).
  – Generally two separate markets!

• August 17, 2000 El Paso has an explosion on one of its two pipelines to California creating an even greater bottleneck.

• Prices in California skyrocket…up to $60/mmBtu in Southern California.

• Regularly between $10 and $20 per mmBtu in Southern California.
  – Price is about half or less in Northern California

Public Utility Research Center, University of Florida
Impact of Gas Prices on the Fuel Cost for Generating 1 MW

• 10,000 Btu/kWh unit
  – @ $10/mmBtu the fuel cost is $100/MWh
  – @ $15/mmBtu the fuel cost is $150/MWh
  – @ $25/mmBtu the fuel cost is $250/MWh
  – @ $60/mmBtu the fuel cost is $600MWh

• 15,000 Btu/kWh unit
  – @ $10/mmBtu the fuel cost is $150/MWh
  – @ $15/mmBtu the fuel cost is $225/MWh
  – @ $25/mmBtu the fuel cost is $375/MWh
  – @ $60/mmBtu the fuel cost is $900MWh
Rainfall/Snowfall and Hydro Resources

- California is dependent upon hydro resources in state (about 13,000 MW capacity) and from imports from the Northwest.
- A lot of the in-state hydro is run-of-river...runs mostly in spring and summer.
- One of the driest 2 year stretches on record in the Western US starting spring 2000.
- Water levels at the second lowest level since record keeping began.

Public Utility Research Center, University of Florida
Rainfall/Snowfall and Hydro Resources

• Hydro resources generally have environmental restrictions as a part of their licenses.
  – Salmon runs, recreation, barge traffic.

• BPA and other northwestern utilities that are dependent upon hydro do not have enough for themselves and go into the wholesale power market driving up demand.
  – Requests from industrials (aluminum smelters) to shut down to save water resources.

• Resources have been run harder this winter to help California...even less for this summer!
Load Growth

• Forecasts have been about 1.5%-2% per year.
• The actual growth in some parts of the west, including California has been in the 3% range.
  – Population growth, the new high tech internet economy.
• Strong, prolonged economic expansion.
• Some point to peak load in Summer 2000 being lower than 1999 as saying this is overblown.
• But total load served is way up!
Generator Outages

- Higher than expected rates of forced outages this year.
- Some say this is *prima facia* evidence that generators are exercising market power!
- There may be some plausible explanations for this.
  - Because of the drought and the higher demands, thermal (fossil) units have been pushed harder, and are more likely to break down. These units are older, and more likely to have problems.
  - Other units may be constrained on the numbers of hours they can operate due to environmental restrictions.
Generator Outages

• Impact of the hard price cap
  – Others may not have control equipment and must go into the pollution permit market which has gotten expensive. Can’t keep operating costs under the cap.
  – Other may elect to not run, but instead sell gas on the open market. Can make more money than under cap.

• Qualifying facilities (QFs) shutting down because they have not been paid by the IOUs!
Entry of New Generation is Difficult

- Since the CEC began permitting projects in 1979, only (fill this in) MW have been permitted.
- The site and environmental permitting is conducted by the California Energy Commission (CEC).
- It takes 2-3 years to go through this process.
- From the time a project is announced to the time it is actually operational is 5-7 years.
Entry of New Generation is Difficult

- On top of dealing with the CEC, projects must face the NIMBY and BANANA problem.
  - NIMBY: Not In My Back Yard.
  - BANANA: Build Anything Nowhere Around or Near Anybody.
  - Calpine’s Metcalf project in San Jose.
- Must also deal with local authorities
  - AES and Huntington Beach
Air Pollution Restrictions

• When generating plants are permitted, there are often restrictions on the numbers of hours a unit can operate, or on its emissions.
• In many cases in California, markets for tradable emissions permits have been developed.
• Permits are allocated based upon some historical measure (output or input).
• The idea is to reduce pollution at the lowest possible cost.
• In many cases these constraints became binding!
  – Hours, emissions, or permits.
Air Pollution Market in Southern California (SCAQMD)

• Typically, permit prices have been from $1 to $3 per pound of emissions ($2000-$6000/ton).
• The price of permits has skyrocketed to at times over $40 per pound (over $80,000/ton).
• Why? Many units have run harder and more often early in the year, using up their allocated permits.
• Just a plain scarcity problem at hand!
Impact of Pollution Permit Prices on Generating 1 MW

- 10,000 Btu/kWh unit, with an emissions rate of .28 lbs./mmBtu (no controls)
  - @ $2/lb. The pollution cost is $5.60/MWh
  - @ $10/lb. The pollution cost is $28/MWh
  - @ $25/lb. The pollution cost is $70/MWh
  - @ $40/lb. The pollution cost is $112/MWh.

- For a 15,000 Btu/kWh unit with no control, multiply the above figures by 1.5.
Potential Market Power Abuses

• Many studies have been conducted by many smart economists and they say that generators are indeed exercising market power!

• A small minority of economists, though, have said that market power may be present, but it is not the overriding factor in the run-up in prices!

• Certainly, it seems then FERC Chairmen (Hoecker and Hebert) don’t think there is market power.

• California’s Governor, Gray Davis, and many politicians seem to think so.

• Can be made worse by transmission constraints!

• Flaws in the market design have been identifies that would allow games to be played…but is this market power?
What is Market Power?

- It is the ability to withhold supply from the market in order to drive up prices.
- This can be done in one of two ways…
  - **Physical Withholding:**
    - Do not offer up some of your resources to the market.
    - Could be done by faking outages.
  - **Economic Withholding:**
    - Bid some of your resources in at well over marginal cost.
- **What is marginal cost?**
  - It is the cost of providing one more unit of supply. It should include opportunity costs!
A Small Example

- Suppose you are a generation owner with a 10,000 Btu/kWh heat rate unit that has no pollution controls.
- Your out-of-pocket costs for gas are $3.00/mmBtu and your NOx permit costs you nothing (it is part of your allocation).
- Assume a $2/MWh cost for variable operation and maintenance costs (O&M).
- This gives you an out-of-pocket marginal cost of $32/MWh.
- Is this your marginal cost? The answer is NO!
- Implicitly, you as a generation owner could also play in the fuel market, or in the NOx permit market. To do so means not running.
A Small Example…continued

• So, the opportunity cost of operating is the forgone profits of not operating and playing in the other markets! In order to operate, you must be indifferent between operating and not operating in terms of profits.

• Further suppose that the price of gas is $15/mmBtu and the price of NOx permits is $20/lb.

• Not Operating:
  – Avoid using 10 mmBtu of gas per MWh of avoided generation that could be sold at $15/mmBtu and only cost you $3.00. This results in a profit of $12/mmBtu sold or $120/MWh of avoided generation.
  – Avoid emitting 2.8 lbs. Of NOx with each MWh of avoided generation that can be sold at $20/lb. This results in a profit of $20/lb. Or $56/MWh of avoided generation.
  – The total profit by not operating is $176/MWh of avoided generation.
A Small Example...continued

- In order to be indifferent between operating and not operating add the $176 “opportunity” cost to the out-of-pocket cost of $32 to get a marginal cost of $208/MWh.
- This example is certainly not with the most inefficient of units selling into the California market or with the highest gas or permit prices.
- It could also be the case that generators could sell out of California if the profits from doing so are greater than the profits from not operating!
- Some generators indeed did not operate to sell gas in the gas market when it hit $60/mmBtu!
- It is unknown whether generators sold NOx permits.
Has the Crisis Passed?

- Prices have started coming down since the late summer of 2001...why?
  - Spot prices in the $25-$35/MWh range.
  - Many units have come out of maintenance outages.
  - QFs have been paid some money and are now coming back on line.
  - Pollution permit prices capped at $7.50/lb.
  - Gas market fundamentals...prices dropped as low as $2/mmBtu.
  - Early spring thaw with better than expected hydro...for now.
  - Some new units have come on line
  - CONSERVATION! About 10-15% below what would be expected given conditions in state.
  - Maybe the long-term deals signed by the Governor?
  - Maybe the threats of refunds and legal action?
  - Now, the state is re-selling power to the grid for a fraction of what they paid.
  - New generation coming on-line for 2002...but what about the future?
The Crisis Gets New Life

- In December 2001 Enron files for bankruptcy…ironic that a company that supposed profited from the crisis is insolvent.
- With 2002 being an election year, Gov. Davis attempts to keep the talk of $9 Billion in refunds in everybody’s mind.
- FERC ALJ recommends that refunds may only amount to about to $1 Billion, and proceedings ongoing to exactly determine refunds.
- With spot prices in the $25-$35/MWh range and long-term contracts paying currently up to 4-5 times that for power currently, Davis has pressed for renegotiation of contracts.
  - Many firms have done so, but only addressing the the end of the 10-20 year deals…drops the firms from further litigation threats.
  - Other companies are also looking at renegotiation.
The Crisis Gets New Life

• With Enron in bankruptcy, they become the focal point of the investigation by FERC, SEC, and CFTC into possible manipulation of markets in California and the west.

• Internal Enron memos reveal Enron trading strategies that have names such “Fat Boy”, “Death Star”, and “Get Shorty”.
  – These strategies detail how Enron exploited market design flaws.
  – These were not a shock to those “in the know”.

• However, western politicians point to the memos as proof that Enron manipulated markets illegally…most experts however, point out that these strategies were not illegal…and really had small impacts on the overall $9 Billion owed by California.

• The situation is now what one could call a political witch hunt…with Enron being hung out to dry!
New Market Design

- California is moving toward a NYISO/PJM type market design.
- Progress has been held up in the stakeholder process.