ELECTRICITY MARKET INSTITUTIONS, TEXAS, AND THE CALIFORNIA MELTDOWN

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The New Texas Electric Market and
How it Compares to the California Market

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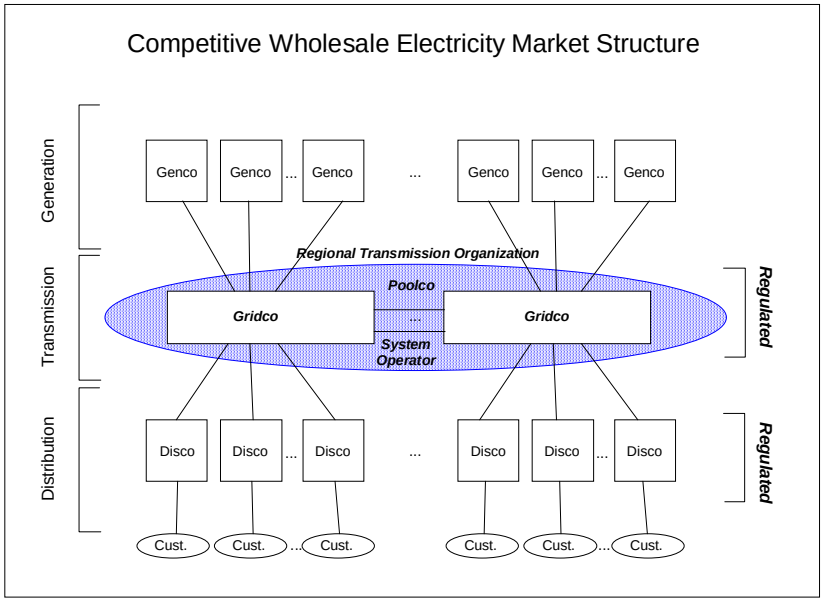
ELECTRICITY MARKET Competitive Structure

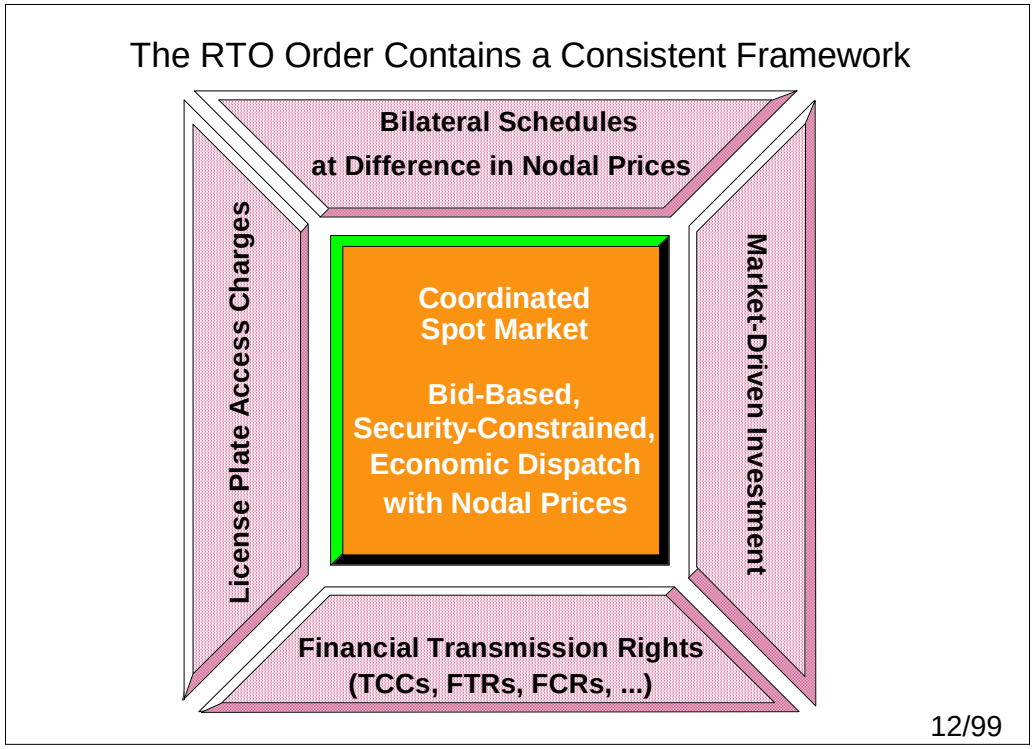
The usual separation into generation, transmission, and distribution is insufficient. In an electricity market, the transmission wires and the pool dispatch are distinct essential facilities.



The special conditions in the electricity system stand as barriers to an efficient, large-scale bilateral market in electricity. A pool-based market model for regional coordination helps overcome these barriers.

ELECTRICITY MARKET — A Market Framework

The Regional Transmission Organization (RTO) Millennium Order (Order 2000) contains a workable market framework that is working in places like the Pennsylvania-New Jersey-Maryland Interconnection (PJM).



Poolco…ISO…IMO…GO/SO…Transco…RTO…: "A rose by any other name …"

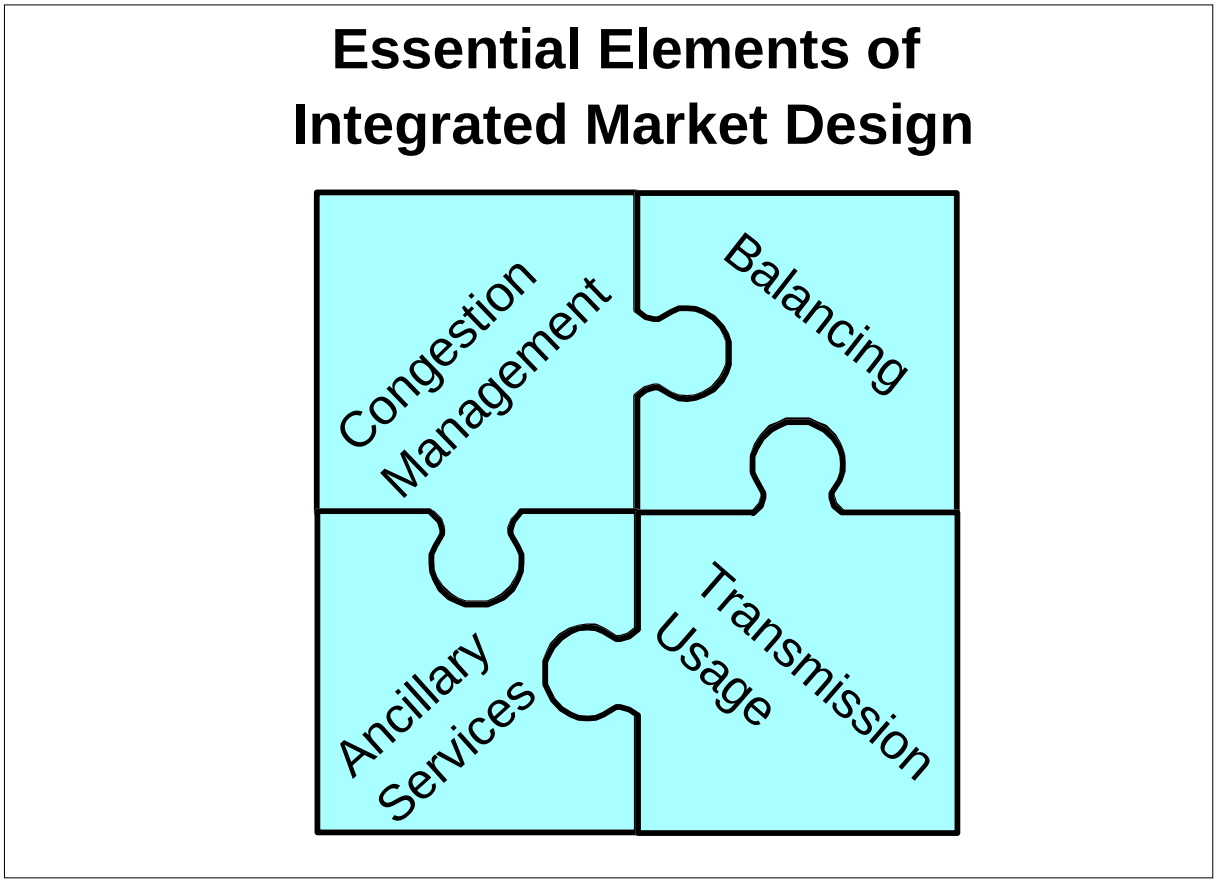
ELECTRICITY MARKET A Market Framework

The core feature of a bid-based, security constrained economic dispatch with locational prices can be found in many existing or announced market designs.

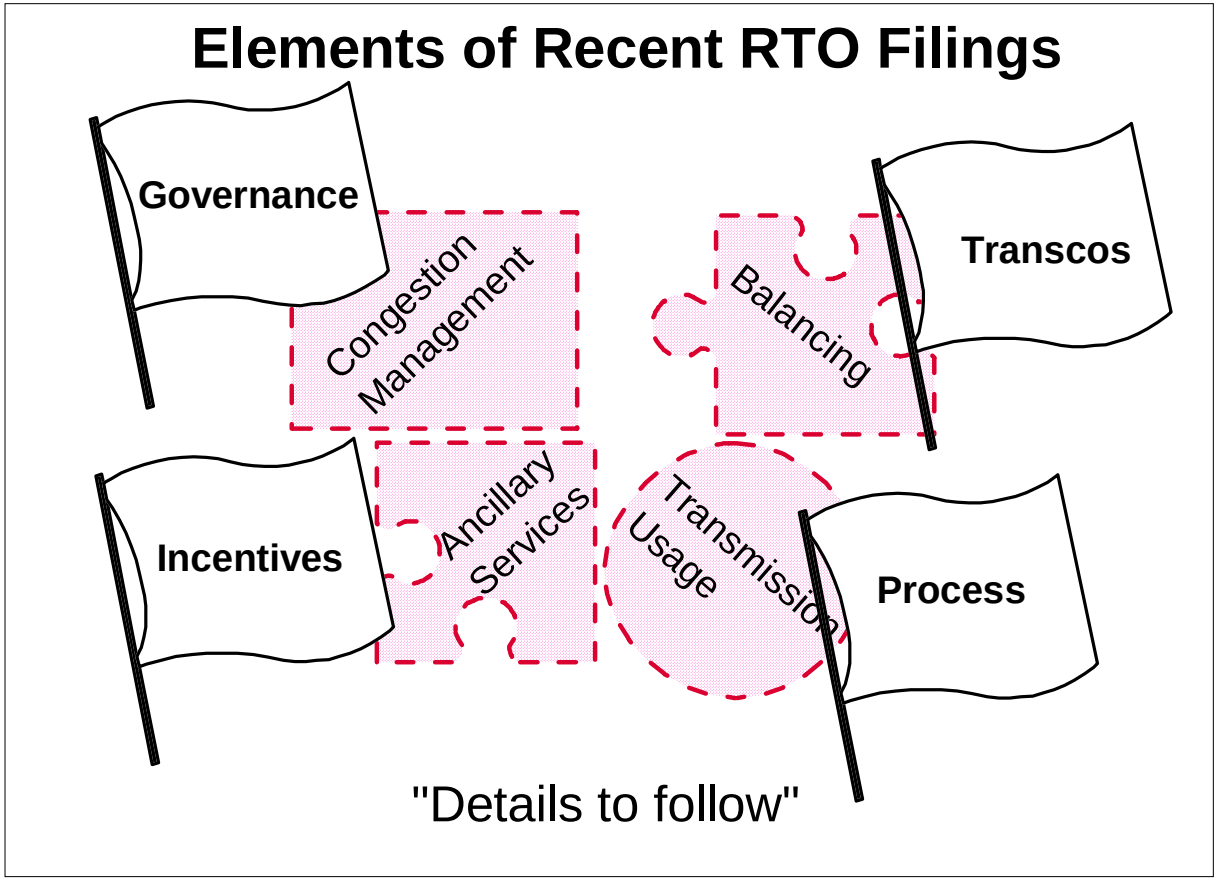
- Argentina.
- Bolivia.
- Chile.
- Mexico (proposed).
- New England (proposed).
- New York.
- New Zealand.
- Norway (dynamic zones).
- PJM.
- Peru.
- and more .... .

The breadth of application and success of the framework dispel the notion that the model is too complex to be implemented. We now have both the theory and substantial operating experience.

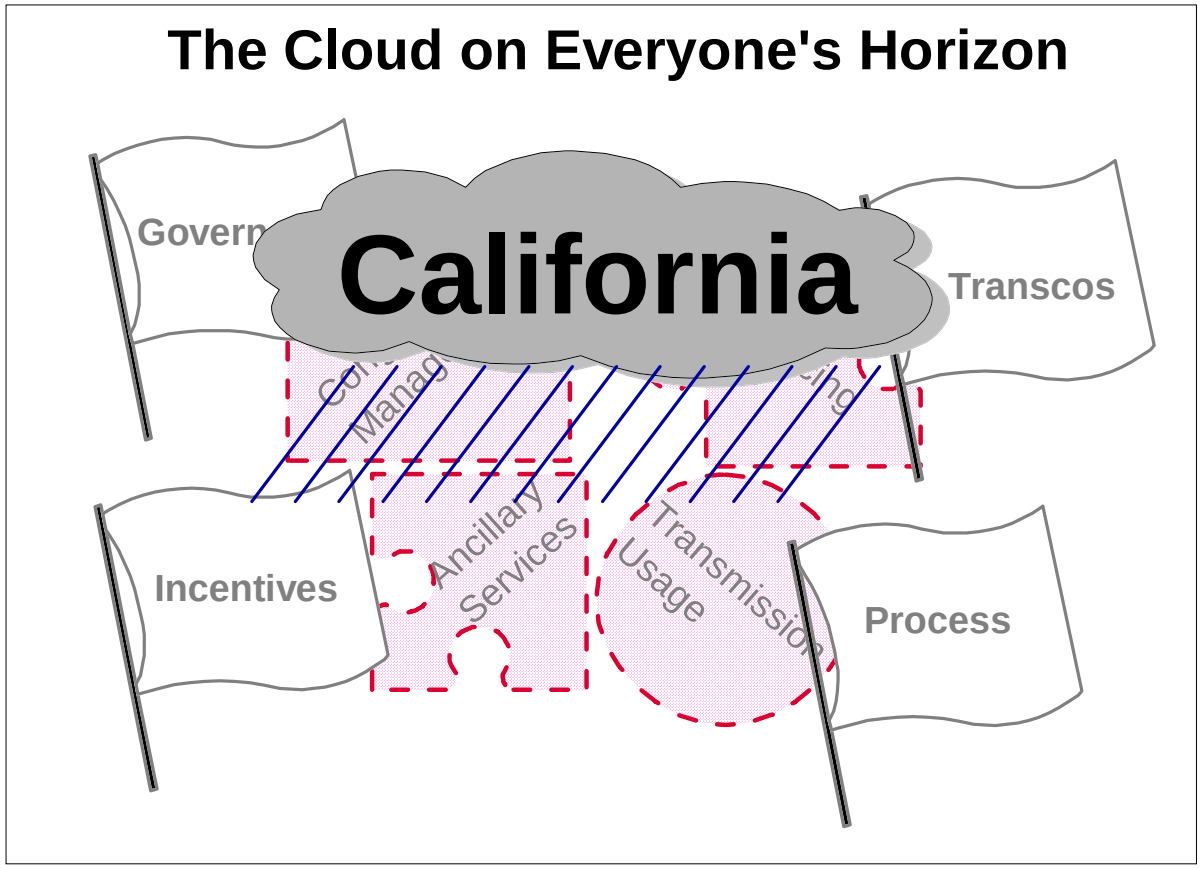
The critical features for a successful electricity market include close coordination of the elements that determine bid-based security constrained economic dispatch. We know how to make the pieces fit together. And we know that the pieces must fit together.



The initial RTO filings display a great diversity of approaches, but there are some common themes. Most importantly, the emphasis is not on the essential elements that seem difficult and controversial. The focus is on governance and issues that seem easier to discuss.



The crisis in California has become the cloud on everyone's horizon. The problems are serious and surprising. The precedents will affect the speed and content of electricity restructuring developments everywhere.



ERCOT is not California. There are differences in market conditions and restructuring policy.

Market Conditions: ERCOT is reported to have both adequate generation capacity and sufficient transmission resources.

Retail Access: Unlike California, the ERCOT rules for retail access and market competition do not prohibit long-term contracts to hedge retail rates. Furthermore, retail rates in ERCOT can adjust to changes in fuel costs or other market conditions.

> **These facts alone distinguish ERCOT from California, where the restrictions on hedging and fixed rates confronted shortage conditions and created a financial crisis.**

Wholesale Market Design: The ERCOT protocols initially[1] reflected a wholesale market design approach much in common with California. Even before the current policy meltdown in California, these market design flaws were the subject of intense review and much needed reform. These flaws may not be fatal, but ERCOT should avoid repeating the mistakes. There has been real progress in ERCOT.

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[1] For the initial design see ERCOT, "The Market Guide," Version 1.2, February 22, 2001.

The California market design and the initial ERCOT protocols assumed that the functions of the ISO could be largely separated from the operation of a wholesale spot market. This is a mistake.[2]

A False Goal

Minimize the role of the ISO: In an attempt to have a small footprint for the ISO, there is a common argument that the ISO functions should be restricted to reliability and separated from the operation of the spot market. In practice, the lack of an efficient spot market and efficient pricing drives the ISO to intervene ever more, but without the tools of the market. The ISO ends up large and intrusive, and the market works badly or not at all.

Better to

Recognize the minimum requirements of an ISO: There are certain functions that only the ISO can perform, and these should be done both efficiently and to support a competitive market. Done right, the result is healthy bilateral trading, liquidity, and ease of entry.

It is not good public policy to intentionally design the ISO functions to be inefficient. If we do so, we will succeed, and the ISO will not be able to provide the services that the market needs to handle the complexity of the electricity system. A well designed ISO, operating a spot market, providing price signals, and supporting transmission hedges, results in the smallest footprint possible.

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[2] W. Hogan, "A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy," The Electricity Journal, December 1995, pp. 26-37.

The subsequent direction from the PUCT goes a long way towards a workable market design that can support competition in an electricity market.[3] The proposed Order for ERCOT contains important elements that move sharply towards an ISO offering a coordinated spot market:

> "However, certain ancillary services can be provided only by ERCOT, including balancing energy service." (p. 6)
>
> "Therefore, ERCOT shall amend the Protocols such that it will procure ancillary services through use of simultaneous optimization for assignment of resources to A/S products, and will set prices for each ancillary service to the corresponding shadow price." (p. 7)
>
> "Therefore, ERCOT shall amend the Protocols such that it will use a two settlement system for the procurement of ancillary services, whereby the day-ahead period procurements are settled at a MCPC for each ancillary service that is set at the time that the day-ahead selected A/S bids are announced (13:30). A second MCPC for each A/S, determined at the end of the adjustment period, shall be used to settle any additional procurements of A/S capacity taking place during the adjustment period for each operating hour." (p. 8) (MCPC: market clearing price for capacity)

Were it not for the ERCOT balanced schedule requirement, these changes would put in place the essential elements of a coordinated spot market. Requiring balanced schedules reduces flexibility and efficiency, and was among the first items FERC ordered eliminated in California. The PUCT is right in its concern:

> "The Commission intends to consider in September, 2001 the policy implications of the balanced schedule requirement, and whether the requirement should be relaxed or eliminated." (p. 14)

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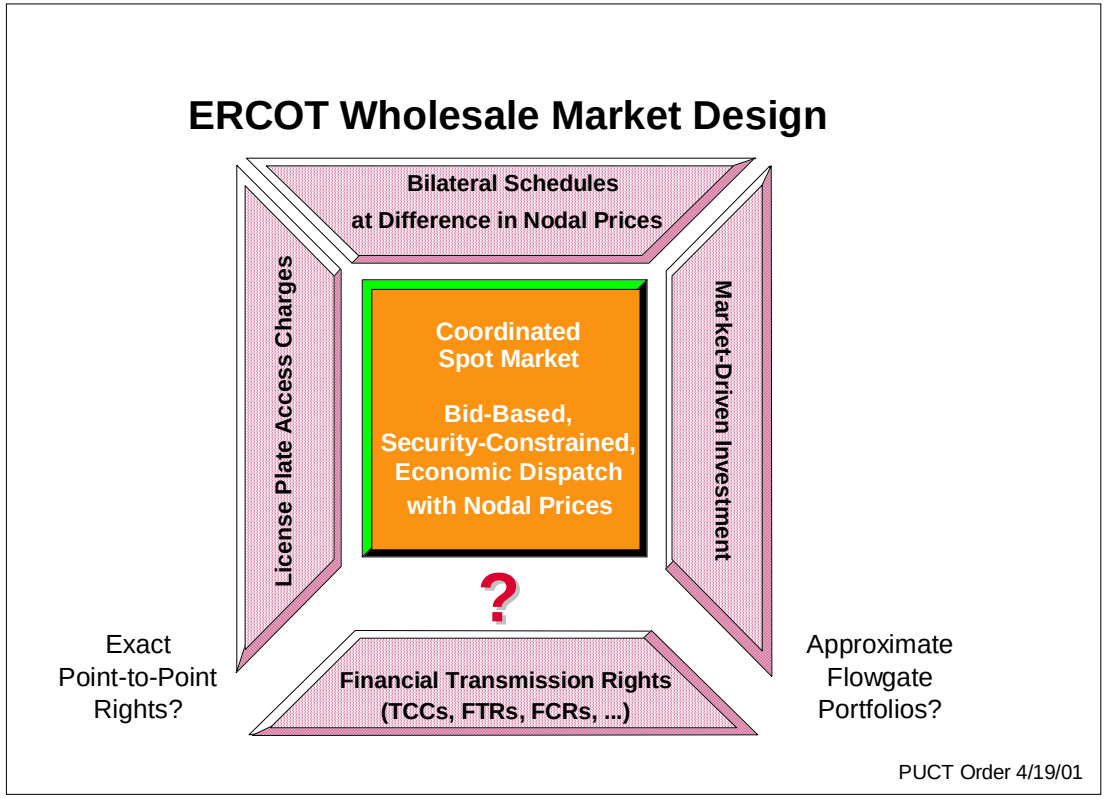
[3] Public utility Commission of Texas, "Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols," Order, Docket No. 23220, April 19, 2001.

The structure of a coordinated spot market must be supported by a consistent pricing system. Here again, the proposed Order moves far towards sensible locational or nodal pricing.

> "… ERCOT shall amend the Protocols to convert to direct assignment of interzonal congestion costs, and base direct assignment of interzonal congestion costs on an adjustable commercial model that employs operational shift factors on the CSCs. In addition, ERCOT shall amend the Protocols to require it to publish advisory updates or forecasts of the shift factors corresponding to CSCs to reflect predicted operating conditions and contingencies. ERCOT's obligation to guarantee full zone-to-zone congestion cost insurance to those who acquire TCRs in proportions based on forecasted shift factors, shall be eliminated." (p. 15) (CSC: commercially significant constraint. TCR: transmission congestion right.)
>
> "Therefore, ERCOT shall amend the Protocols to define TCRs (in units of megawatts) as pure financial instruments entitling their holders to the shadow prices on directional flowgate constraints; the "use it or lose it" rule shall be eliminated." (p. 16)
>
> "In order to reduce the potential for gaming of transmission congestion, ERCOT shall amend the Protocols to require direct assignment of intrazonal congestion management costs, through a usage fee that is based on the flow on the congested intrazonal interface. The usage fee shall be set to the operational shadow price on the congested intrazonal interface. The usage fee shall apply to the generation resources that cause the congestion." (p. 18)

There are technical issues about how feasible this would be, but if it works it would produce all the ingredients and the same effect as locational prices that would clear the coordinated spot market.

The Order paints each brush stroke but does not step back to look at the resulting picture.



Point-to-point financial transmission rights would provide a consistent complement to the coordinated spot market with nodal prices. There are good reasons to make this design choice.

Without clarifying the whole picture, the interim Order misses an important opportunity to simplify the problem and improve the tools available for the market.

> "…ERCOT should not be in the business of insuring transmission users against changes in shift factors." (p. 15)
>
> "The net revenues resulting from the usage fee shall be distributed, or credited against uplift charges, on a load-ratio basis within the zone in which the congested intrazonal interface is located, or used to fund construction of transmission facilities." (p. 18)
>
> "However, to the extent that doing so proves infeasible under the zonal, portfolio-based model embodied in the Protocols, ERCOT shall promptly notify the Commission, so that the Commission can promptly consider ordering the implementation of other alternative congestion management methods, particularly locational marginal pricing." (p. 19)

These comments reflect a PUCT concern that the elements might not be consistent. The concern is justified. Other markets that have adopted locational marginal pricing have relied on point-to-point financial transmission rights. There is no subsidy required, and they are easier to use than the zonal-flowgate-interface rights of the current ERCOT design. On this point the ERCOT the design reflects the heritage of alternative market models that have failed elsewhere.

- Zonal aggregation where either it is not needed or won't work.
- Flowgate portfolios that have to be assembled to produce what comes naturally out of the coordinated spot market and point-to-point rights.

Electricity systems are not simple. The reality of electricity systems creates an interest in simplifying market design to provide better support for commercial transactions. The benefits of simplification are clear, other things being equal. However, other things are usually not equal, and the law of unintended consequences often dictates that what appears simple may turn out to be complex in the end. What may appear complex can be simple in the end if it is consistent with the reality of the electric system and does not require substantial non-market interventions to make the market work.

- **Congestion Zones**. Full locational pricing at every node in the network is a natural consequence of the basic economics of a competitive electricity market. However, it has been common around the world to assert, usually without apparent need for much further justification, that nodal pricing would be too complicated and aggregation into single price zones, with socialization of the attendant costs, would be simpler and solve all manner of problems.

- **Flowgates and Decentralized Congestion Management.** If a single contract path is not good enough, perhaps many paths would be better. Since power flows along many parallel paths, there is a natural inclination to develop an approach to transmission services that would identify the key links or "flowgates" over which the power may actually flow, and to define transmission rights according to the capacities at these flowgates.

The debate over alternative electricity market institutions often confuses two design issues: what is appropriate as a basis for design of the system operator, and what would be appropriate as the design of a stand alone business offering a service within the framework of the market design.

ELECTRICITY MARKET Congestion Zones

Aggregation of many locations into a few congestion zones creates problems when market participants have choices. In general, zonal pricing is not consistent with market opportunity costs. The costs of transmission congestion can be very high, and failure to internalize these costs can disrupt the energy market. This is not a mere technical detail. From the perspective of designing market institutions, response to prices is the most important phenomenon.

> **Fact:** A single transmission constraint in an electric network can produce different prices at every node. Simply put, the different nodal prices arise because every location has a different effect on the constraint. This feature of electric networks is caused by the physics of parallel flows. Unfortunately, if you are not an electrical engineer, you probably have very bad intuition about the implications of this fact. You are not alone.
>
> **Fiction:** We could avoid the complications of dealing directly with nodal pricing by aggregating nodes with similar prices into a few zones. The result would provide a foundation for a simpler competitive market structure.

If prices closely reflect operating conditions and marginal costs, then market participants can have numerous choices in the way they use the transmission system. However, if pricing does not conform to the operating conditions, then substantial operating restrictions must be imposed to preserve system reliability. Customer flexibility and choice require efficient pricing; inefficient pricing necessarily limits market flexibility.

Complex problems have been created by the simplification of zonal congestion pricing:

- The first region in the United States to abandon a zonal pricing model after it failed in practice was PJM, from its experience in 1997 when its zonal pricing system prompted actions which caused severe reliability problems. Given this experience, PJM adopted a nodal pricing system that has worked well since March 1998.[4]

- Subsequently, the original one-zone congestion pricing system adopted for the New England independent system operator (ISONE) created inefficient incentives for locating new generation.[5] To counter these price incentives, New England proposed a number of limitations and conditions on new generation construction. Following the Commission's rejection of the resulting barriers to entry for new generation in New England, there developed a debate over the preferred model for managing and pricing transmission congestion.[6] In the end, New England proposed go all the way to a nodal pricing system.[7]

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[4] William W. Hogan, "Restructuring the Electricity Market: Institutions for Network Systems," Harvard-Japan Project on Energy and the Environment, Center for Business and Government, Harvard University, April 1999, pp. 37-44.

[5] The use of zones for collecting transmission fixed charges is not the issue here. The focus is on managing transmission congestion. For a critique of the previously proposed one-zone congestion pricing system, see Peter Cramton and Robert Wilson, "A Review of ISO New England's Proposed Market Rules," Market Design, Inc., September 9, 1998.

[6] Federal Energy Regulatory Commission, New England Power Pool Ruling, Docket No. ER98-3853-000, October 29, 1998.

[7] ISO New England, "Congestion Management System and a Multi-Settlement System for the New England Power Pool," FERC Docket EL00-62-000, ER00-2052-000, Washington DC, March 31, 2000. The proposal includes full nodal pricing for generation and, for a transition period, zonal aggregation for loads.

Complex problems have been created by the simplification of zonal congestion pricing (cont.):

- A similar zonal congestion management market design created similar problems in California, which prompted the FERC to reject a number of ad hoc market adjustments and call for fundamental reform of the zonal congestion management system. "The problem facing the [California] ISO is that the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced."[8]

- The zonal pricing system in Alberta, Canada, apparently produced a related set of incentives that failed to give generators the price signal to locate consistent with the needs of reliability: "Most of the electricity generation sources are located in the northern part of the province and ever-increasing amounts of electricity are being transported to southern Alberta to meet growth, ... [t]his is causing a constraint in getting electricity into southern Alberta and impacting overall security of the high-voltage transmission system."[9] As a result, Alberta has proposed a central generation procurement process under the transmission operator to provide a means to get generation built in the right place. This is hardly a true simplification, nor is it consistent with the original intent to move towards a competitive market and away from monopoly procurement.

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[8] Federal Energy Regulatory Commission, "Order Accepting for Filing in Part and Rejecting in Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion," Docket ER00-555-000, 90 FERC 61, 000, Washington DC, January 7, 2000, p. 9. See also Federal Energy Regulatory Commission, "Order Denying Requests for Clarifications and Rehearing," 91 FERC 61, 026, Docket ER00-555-001, Washington DC, April 12, 2000, p. 4.

[9] "Alberta Transmission Czar Wants More Generation," Electricity Daily, Vol. 14, No. 77, April 21, 2000, p. 3.

Since power flows along many parallel paths, there is a natural inclination to develop transmission services that would identify the key links or "flowgates" over which the power may actually flow, and to define transmission rights according to the capacities at these flowgates. The assertion is that the commercially significant congestion can be represented by a system with:

- Few flowgates or constraints.
- Known capacity limits at the flowgates.
- Known power transfer distribution factors (PTDF) that decompose a transaction into the flows over the flowgates.

Under these simplifying assumptions, the decentralized model might work in practice. However, There is some experience with this flowgate model applied as part of the NERC Pilot Project for Market Redispatch in 1999. Despite substantial market need for congestion management, there were *no* successful applications of any decentralized trades under this approach.[10]

The simplified assumptions are not true. [11]

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[10] Congestion Management Working Group of the NERC Market Interface Committee, "Final Report on the NERC Market Redispatch Pilot," November 29, 1999, filed with FERC on December 1, 1999.

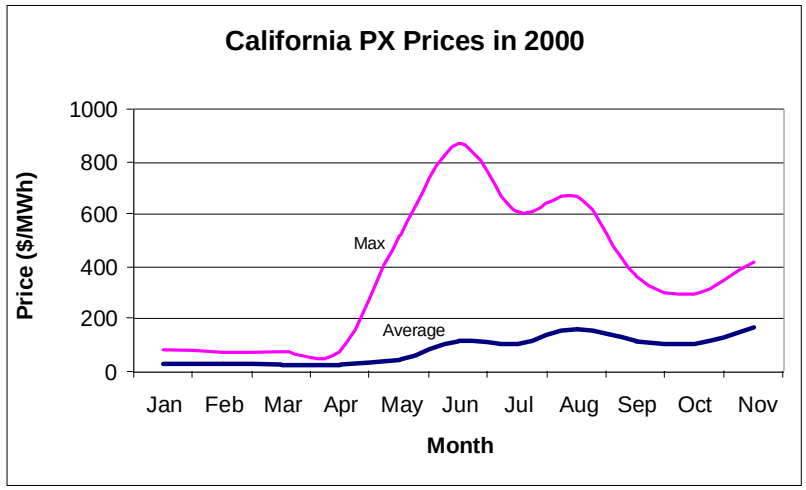
[11] William W. Hogan, "Flowgate Rights and Wrongs," Center for Business and Government, Harvard University, August 2000.

ELECTRICITY MARKET — California Developments

The California crisis erupted in the Summer of 2000. Bad policy combined with bad luck to create an unexpected and unprecedented price explosion.

- **Bad Policy:** Divestiture of thermal generation without vesting contracts left utilities on spot market.
- Rate caps for load at $65 per MWh eliminated demand response.
- Separation of ISO and PX and the myriad associated market design flaws that followed.

- **Bad Luck:** Low water year and unexpected growth in demand throughout the western system.
- Binding environmental constraints and eventually a shortage of gas.



Source: CALPX Hourly UMCP Monthly Max and Average

- **Bad News**: In the Spring of 2000, forward prices were under $80, and viewed as too high.
- From June through November of 2000 prices in the Western Hubs were $100-$800 .
- Panic ensued. Villains were sought. Bankruptcy loomed.
- Restructuring will slow, or stop, or maybe even reverse.

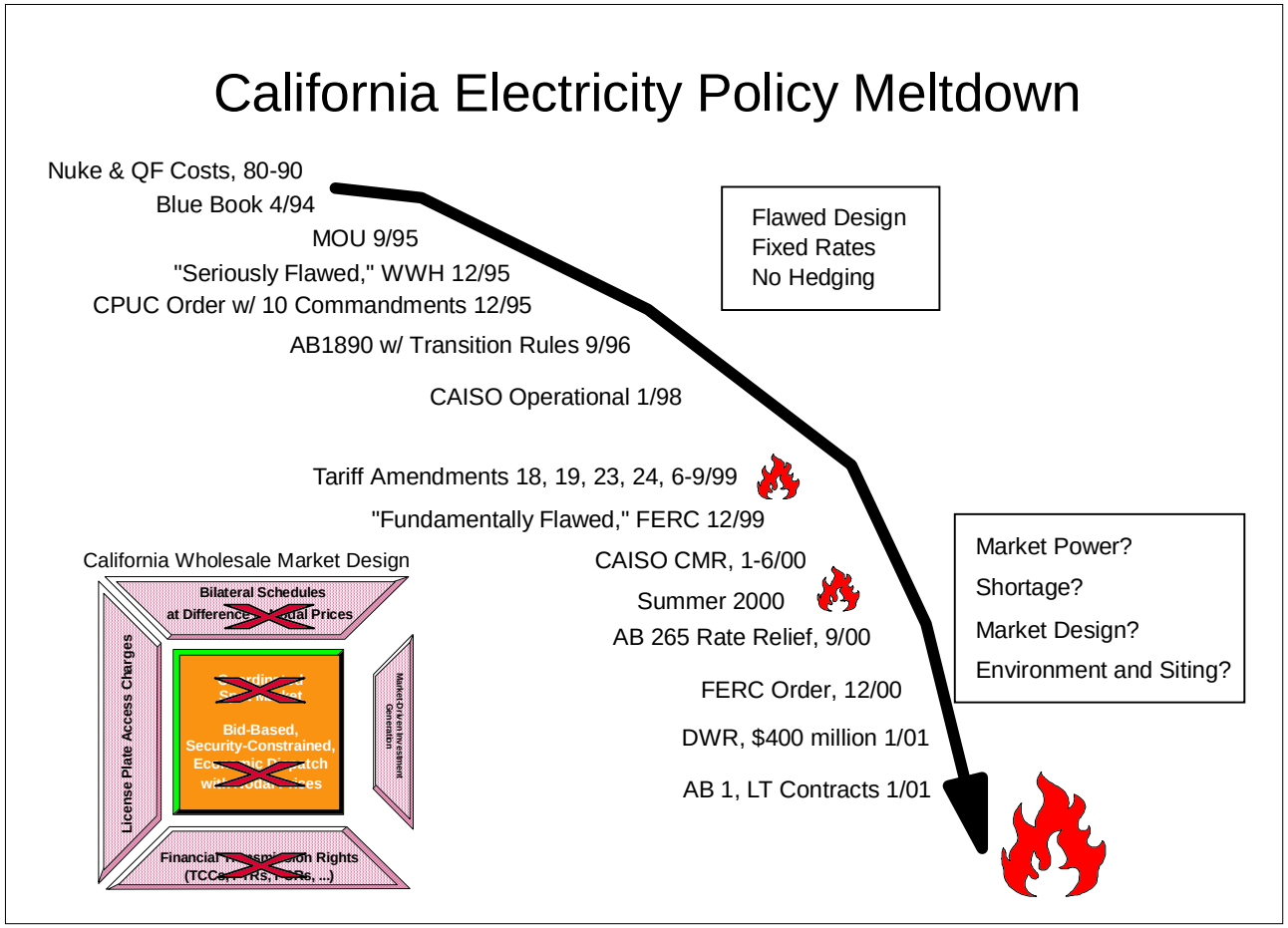
ELECTRICITY MARKET — California Developments

That the California crisis is man made makes it no less serious.

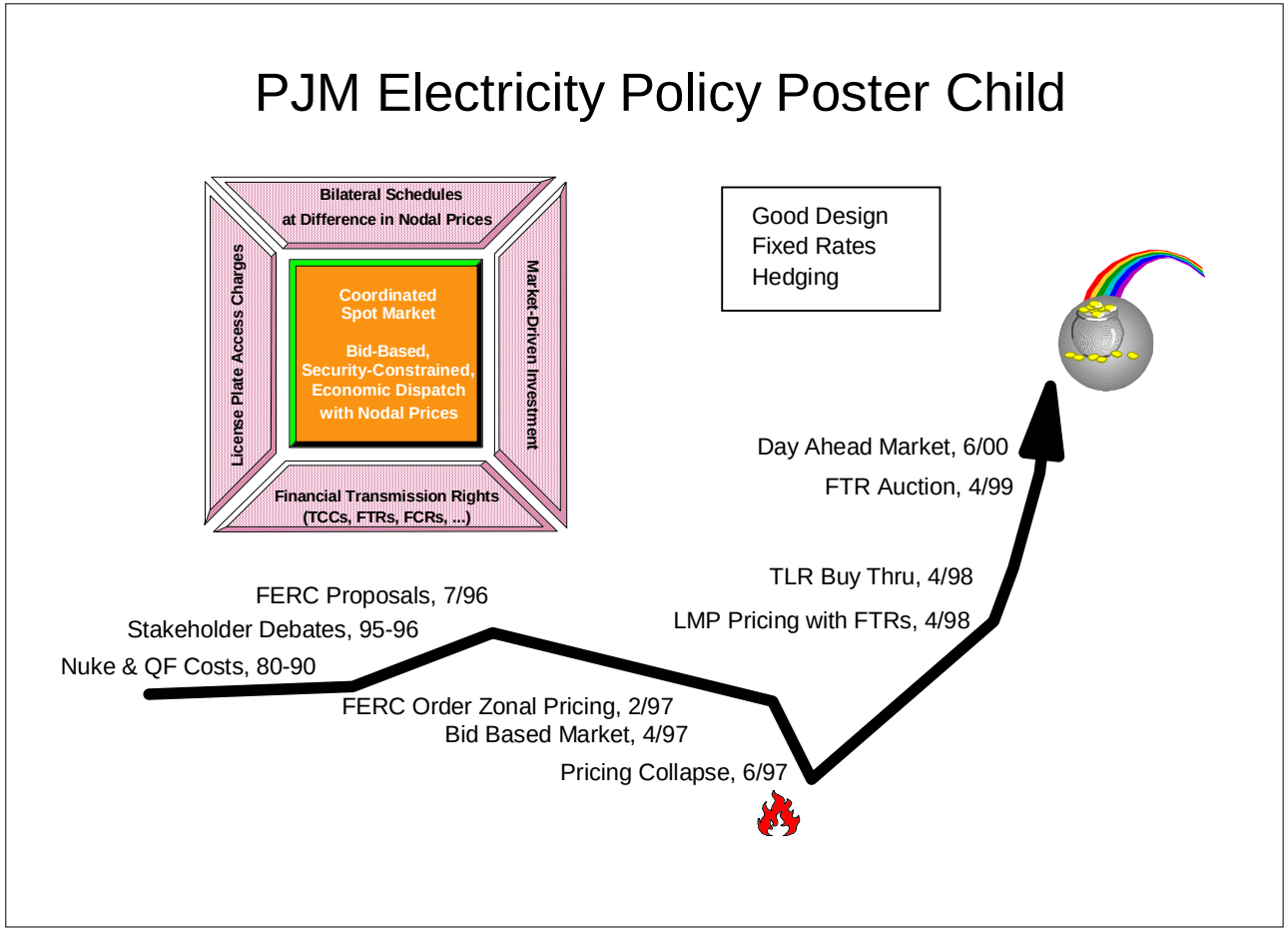
- California electric power bills: 1999 $7.5 B; 2000 $28 B; 2001 $80(?) B.
- Two major utilities, PG&E and SCE, accumulate $12 B in losses and stop paying their bills.
- Federal Government points to Sacramento as the responsible party.
- U.S. Department of Energy issued emergency orders to sell to California.
- Governor and others condemn criminal profiteers from outside the state.
- Governor draws line in sand, promising not to raise retail prices.
- Wholesale prices increase further from fear of default under bankruptcy.
- Company credit ratings drop to junk bond status.
- Intel announces intent to stop building in California.
- California burns through $400 million in state general funds in first two weeks.
- State experiences stage 3 emergencies and rolling blackouts.
- Problem spreads to danger of curtailment of natural gas supplies.
- Wholesale price increases and shortages a problem throughout the western system.
- Water reserves drawn down and retail prices up in many western states.
- California Power Exchange goes out of business.
- California legislates a panic takeover of electricity industry.
- PG&E enters Chapter 11 bankruptcy proceedings.
- **...**

"…California seems to be living in some surreal version of 'The Wizard of Oz,' trapped among the brainless, the heartless and the gutless." (Peter Schrag, editorial, Sacramento Bee, Feb. 7, 2001)

The California meltdown had been expected, but not expected to be as bad as it has been.



The PJM (and NY, soon NE) success stands in sharp contrast to the California meltdown.



ELECTRICITY MARKET California Developments

The immediate California emergency needs to be addressed, and then we can turn attention to the fundamental problems in the development of electricity restructuring.

Ad Hoc "Manifesto," from Solow , McFadden, et al. , January 26, 2001:

- **Pay your bills.**

  This is fundamental. Electricity is not yet a cash-and-carry market.

- **Raise retail prices.**

  Without raising retail prices, there is not enough money to pay the bills. And the incentives to reduce demand are crucial in resolving the short run problem.

- **Look to the long run.**

  The summer of 2001 is not far away. The fundamentals of electricity restructuring need urgent attention in California and elsewhere.

"Didn't make a dent."(anonymous California legislator)

The list of necessary reforms for the California market is long, and the difficulty of identifying and fixing all of the problems has been exacerbated by repeated ad hoc reforms that have dismissed theoretically sound and proven design principles. These principles include:[12]

- The ISO must operate, and provide open access to, short-run markets to maintain short-run reliability and to provide a foundation for a workable market.
- An ISO should be allowed to operate integrated short-run forward markets for energy and transmission.
- An ISO should use locational marginal pricing to price and settle all purchases and sales of energy in its forward and real-time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.
- An ISO should offer tradable point-to-point financial transmission rights that allow market participants to hedge the locational differences in energy prices.
- An ISO should simultaneously optimize its ancillary service markets and energy markets.
- The ISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.

[12] John D. Chandley, Scott M. Harvey, William W. Hogan, "Electricity Market Reform in California," Comments in FERC Docket EL00-95-000, Center for Business and Government, Harvard University, November 22, 2000. pp. 15-25.

ELECTRICITY MARKET — California Fallout

The crisis in the California market presents many challenges to electricity restructuring efforts in the U.S. and elsewhere.

- **Market Monitoring and Market Power Mitigation:** There is a heightened requirement to recognize and mitigate market power.
  - Diagnosis should focus on causes rather than symptoms.

    Causes: Market Power, Scarcity, Environmental Limits, Design Flaws…
    Symptoms: High and Volatile Prices, Reliance on Real Time Markets.

  - Prescription should follow diagnosis.

    Bid Caps vs. Prices Caps.
    Efficient Design vs. Rules and Penalties.

- **Reaction and Regression:** Bad ideas drive out good under the pressure of a market implosion.
  - State takeover of the grid.
  - Commit to long-terms contracts before fixing market design.

- **No Free "Get Out of Jail Cards":** Another market implosion like that seen in California would be the end of efforts to exploit markets for electricity.

The same chronic disease is found in California and in the RTO proposals. In California the case has become acute. Time is running out. The same medicine would work for the acute case and the chronic sufferers. The FERC is on target. However, the success of the RTO Millenium Order depends on two big "ifs." Market reform can work …

- **If FERC means what it says. …**
- **If FERC follow through. …**

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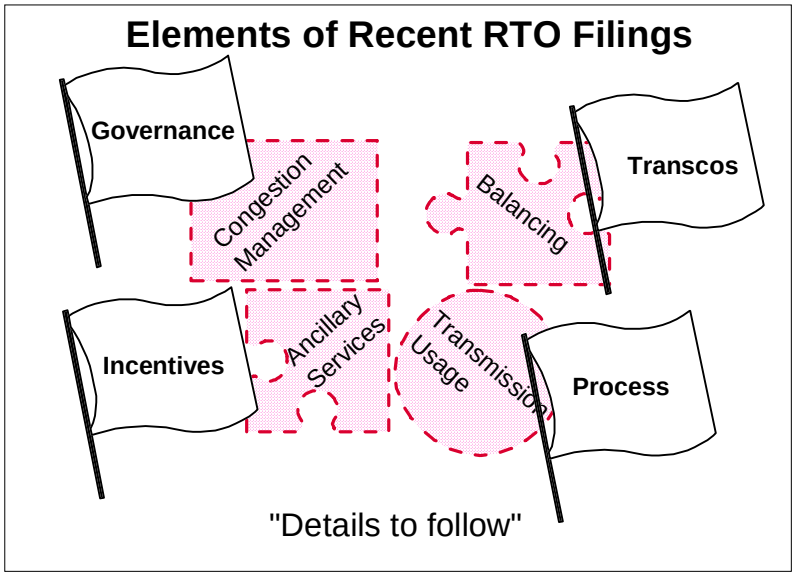

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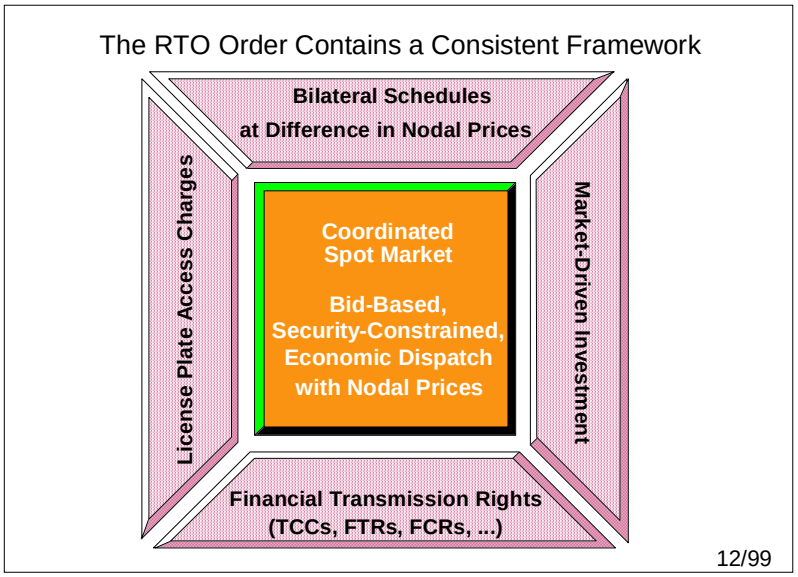
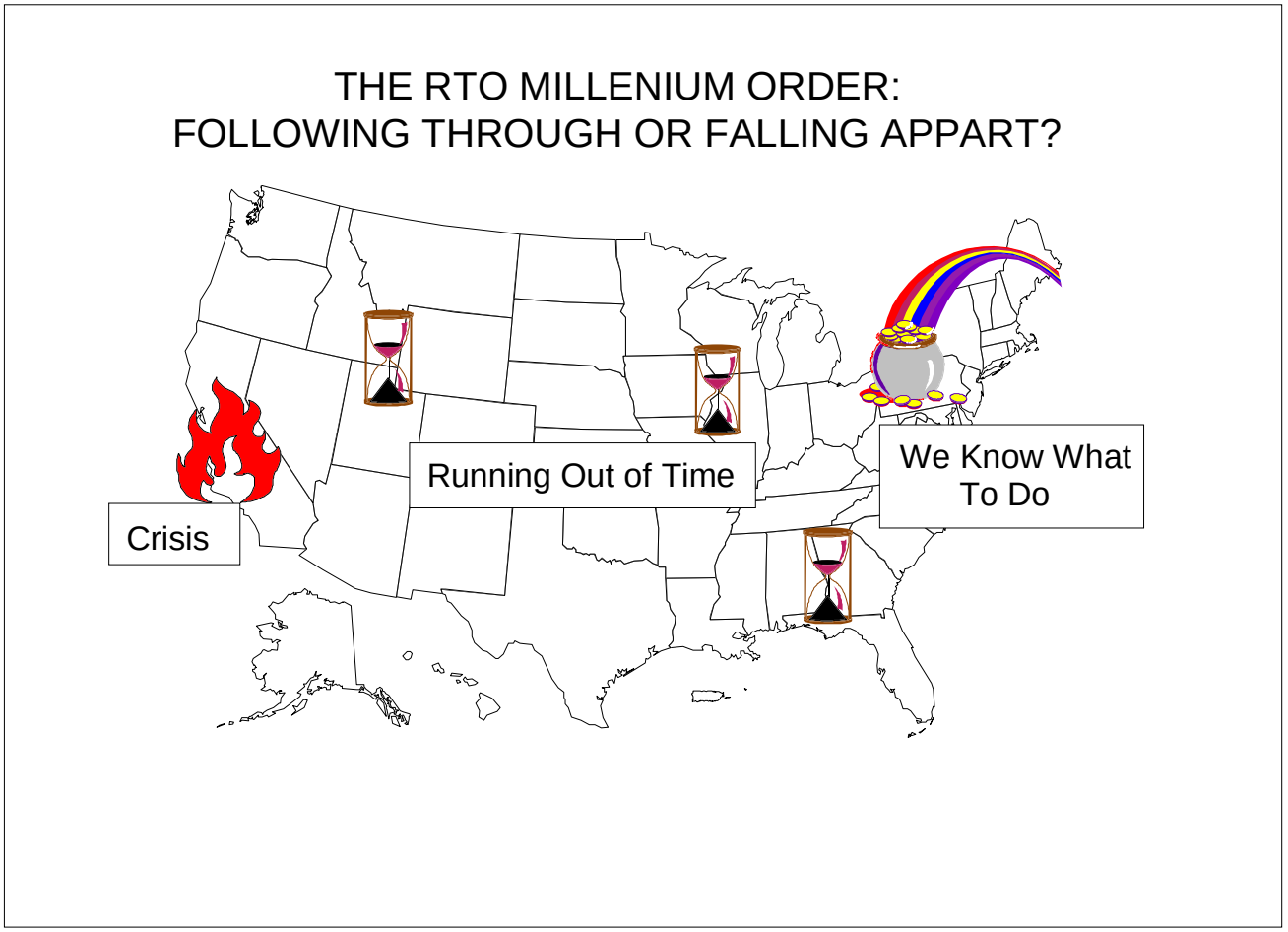


ELECTRICITY MARKET — California Developments

National progress in implementing the advance of regional transmission organizations under the Millennium Order (Order 2000) hangs in the balance. Time is running out.



Supporting papers and additional detail can be obtained from the author. William W. Hogan is the Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University and a Director of LECG, LLC. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for American National Power, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, Calpine Corporation, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, Detroit Edison Company, Duquesne Light Company, Electricity Corporation of New Zealand, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., Mirant Corporation, National Independent Energy Producers, New England Independent System Operator, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, PJM Office of Interconnection, San Diego Gas & Electric Corporation, Sempra Energy, TransÉnergie, Transpower of New Zealand, Westbrook Power, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at http://ksgwww.harvard.edu/people/whogan).