THE RTO MILLENNIUM ORDER: FOLLOWING THROUGH OR FALLING APART?

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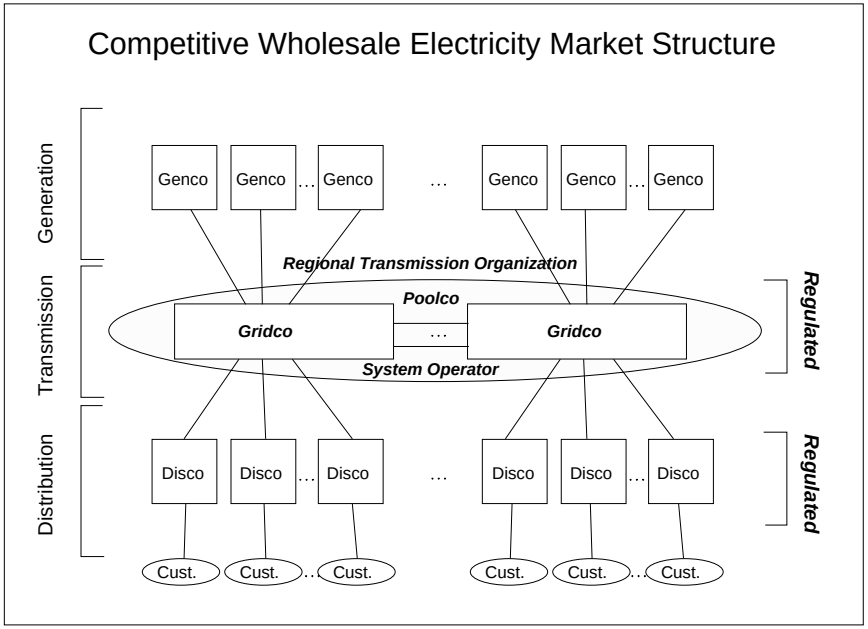
ELECTRICITY MARKET — Competitive Structure

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.

The Federal Energy Regulatory Commission's (FERC) Regional Transmission Organizations [RTO] Final Rule in Order 2000 sets forward a framework for electricity restructuring in support of competitive markets. This RTO Rule recognizes the importance of a coordinated spot or balancing market, and builds on this core idea.

"...it is clear that RTOs are needed to resolve impediments to fully competitive markets."

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, p. 115.)

The FERC has established "characteristics" and "functions" for RTOs:

"...the four minimum characteristics for an RTO: ...

(1) independence from market participants;

(2) appropriate scope and regional configuration;

(3) possession of operational authority for all transmission facilities under the RTO's control; and

(4) exclusive authority to maintain short-term reliability."

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, p. 152.)

The FERC RTO Final Rule sets forward a framework for electricity restructuring in support of competitive markets. The details matter, but there is a great deal of guidance.

In addition, there are eight minimum functions that an RTO must perform. "...an RTO must:

(1) administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;

(2) create market mechanisms to manage transmission congestion;

(3) develop and implement procedures to address parallel path flow issues;

(4) serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;

(5) operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC;

(6) monitor markets to identify design flaws and market power;

(7) plan and coordinate necessary transmission additions and upgrades; [and]

(8) ... ensure the integration of reliability practices within an interconnection and market interface practices among regions."

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, pp. 323-497.)

The independent system operator provides a dispatch function. Three questions remain. Just say yes, and the market can decide on the split between bilateral and coordinated exchange.

- **Should the system operator be allowed to offer an economic dispatch service for some plants?**

The alternative would be to define a set of administrative procedures and rules for system balancing that purposely ignore the information about the costs of running particular plants. It seems more natural that the operator consider customer bids and provide economic dispatch for some plants.

- **Should the system operator apply marginal cost prices for power provided through the dispatch?**

Under an economic dispatch for the flexible plants and loads, it is a straightforward matter to determine the locational marginal costs of additional power. These marginal costs are also the prices that would apply in the case of a perfect competitive market at equilibrium. In addition, these locational marginal cost prices provide the consistent foundation for the design of a comparable transmission tariff.

- **Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?**

The natural extension of open access and the principles of choice would suggest that participation should be voluntary. Market participants can evaluate their own economic situation and make their own choice about participating in the operator's economic dispatch or finding similar services elsewhere.

The RTO Final Rule addresses the three critical questions. The RTO answer is "Just Say Yes."

Should the system operator be allowed to offer an economic dispatch service for some plants?

Yes. "Real-time balancing is usually achieved through the direct control of select generators (and, in some cases, loads) who increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator." (p. 635.) "...proposals should ensure that (1) the generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and (2) limited transmission capacity should be used by market participants that value that use most highly." (pp. 323-333.)

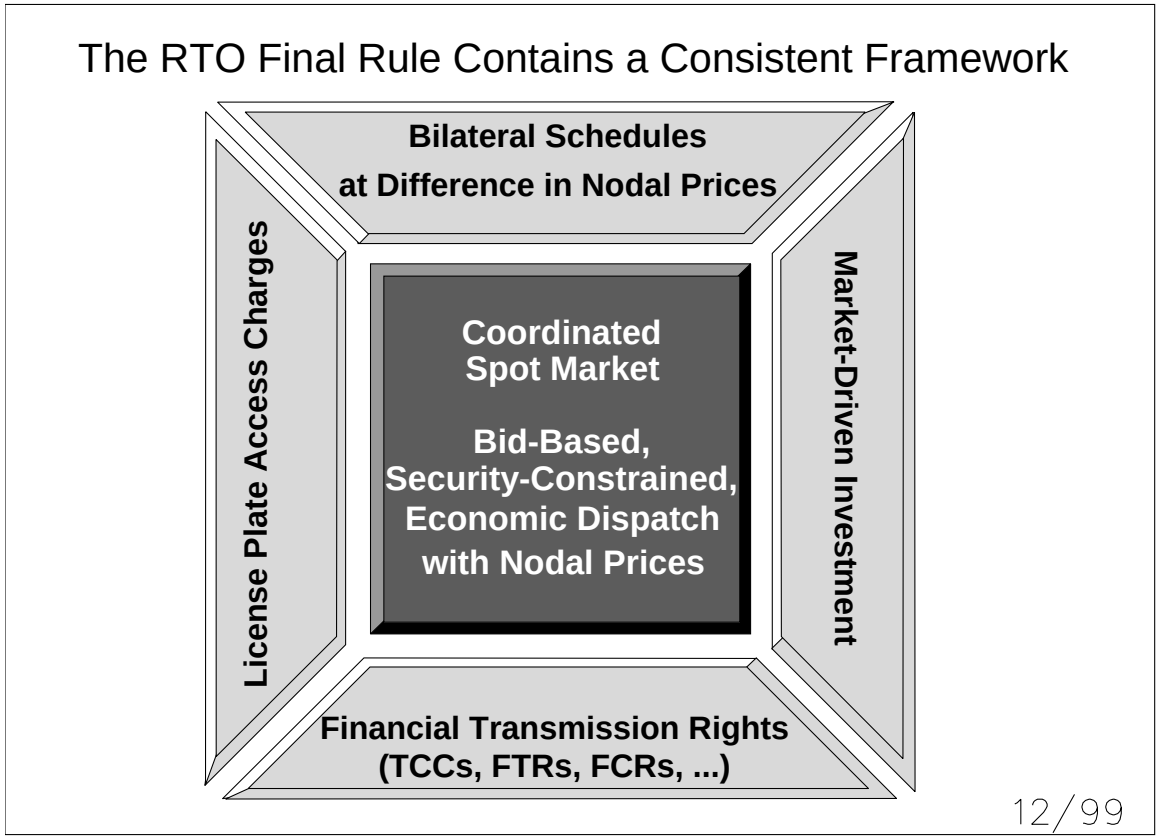
Should the system operator apply marginal cost prices for power provided through the dispatch?

Yes. "...we will require the RTO to implement a market mechanism that provides all transmission customers with efficient price signals regarding the consequences of their transmission use decisions." (p. 382.)

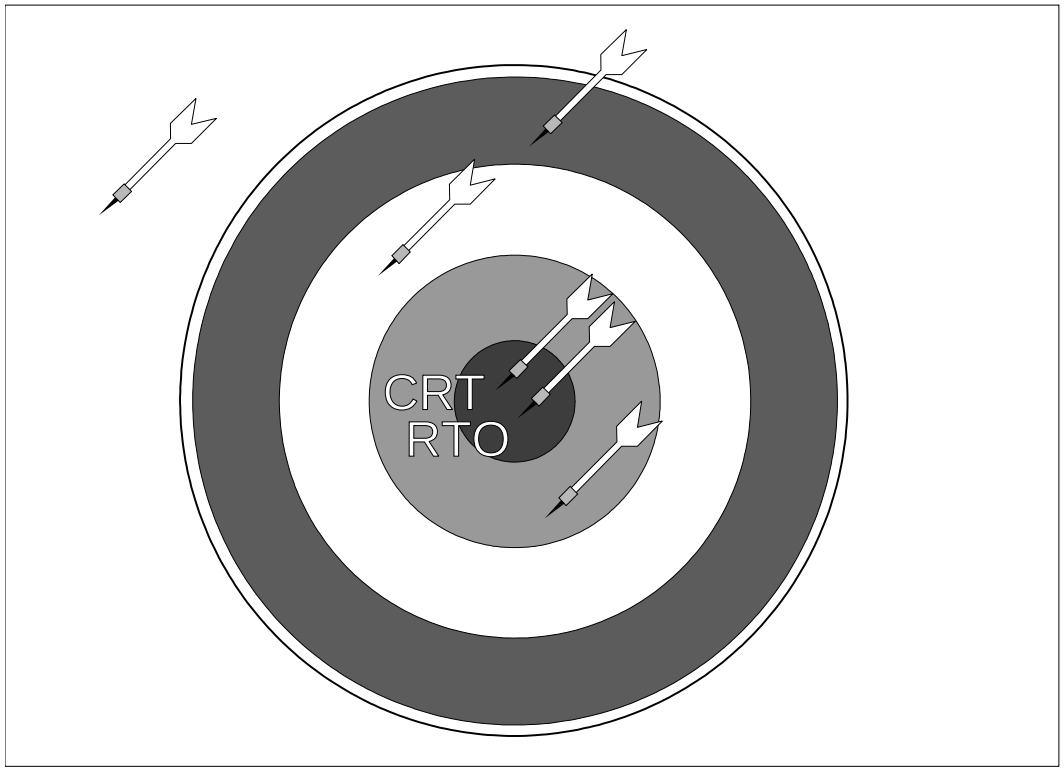
Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?

Yes "The Regional Transmission Organization must ensure that its transmission customers have access to a real-time balancing market. The Regional Transmission Organization must either develop and operate this market itself or ensure that this task is performed by another entity that is not affiliated with any market participant" (p. 423.)

The RTO-Rule and earlier Capacity Reservation Tariff [CRT] contain a workable market framework that is working in places like the Pennsylvania-New Jersey-Maryland Interconnection (PJM).



The FERC is on target. However, the success of the CRT/RTO proposal depends on two big "ifs". The framework can work ...



- **If FERC means what it says.** The record is encouraging here. The basic elements of the CRT proposal, originally criticized by the industry as being unworkable, have been approved by FERC and are working fine in PJM. Soon in New York and New England.

- **If FERC follows through.** The incentive-based carrots may not be enough. In the case of gas open access, and Order 436, the "volunteers" were responding to many FERC-sticks as well. Some regions will do the right thing on their own, but not all. And the interactions, such as through TLR, cry out for more consistency. How long before FERC makes this mandatory? "If you know what to do, do it." We know what to do.

The RTO Final Rule sets for a timetable for voluntary formation of RTOs. If there are not enough volunteers, then ... ?

"...all public utilities (with the exception of those participating in an approved regional transmission entity that conforms to the Commission's ISO principles) that own, operate or control interstate transmission facilities must file with the Commission by October 15, 2000, a proposal for an RTO with the minimum characteristics and functions to be operational by December 15, 2001, or, alternatively, a description of efforts to participate in an RTO, any existing obstacles to RTO participation, and any plans to work toward RTO participation."

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, p. 7.)

" The goal of this rulemaking is to form RTOs voluntarily and in a timely manner. The alternative to a voluntary process is likely to be a lengthy process that is more likely to result in greater standardization of the Commission's RTO requirements among regions. Although the Commission has specific authorities and responsibilities under the FPA to protect against undue discrimination and remove impediments to wholesale competition, we find it appropriate in this instance to adopt an open collaborative process that relies on voluntary regional participation to design RTOs that can be tailored to specific needs of each region.""

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, p. 8.)

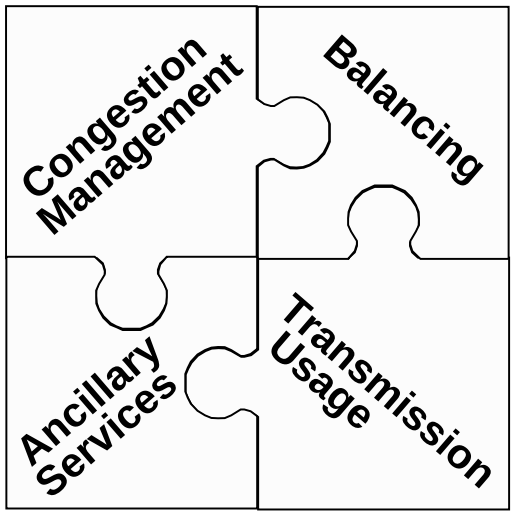
The core feature of a bid-based, security constrained economic dispatch with locational prices can be found in many existing or announced market designs.

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

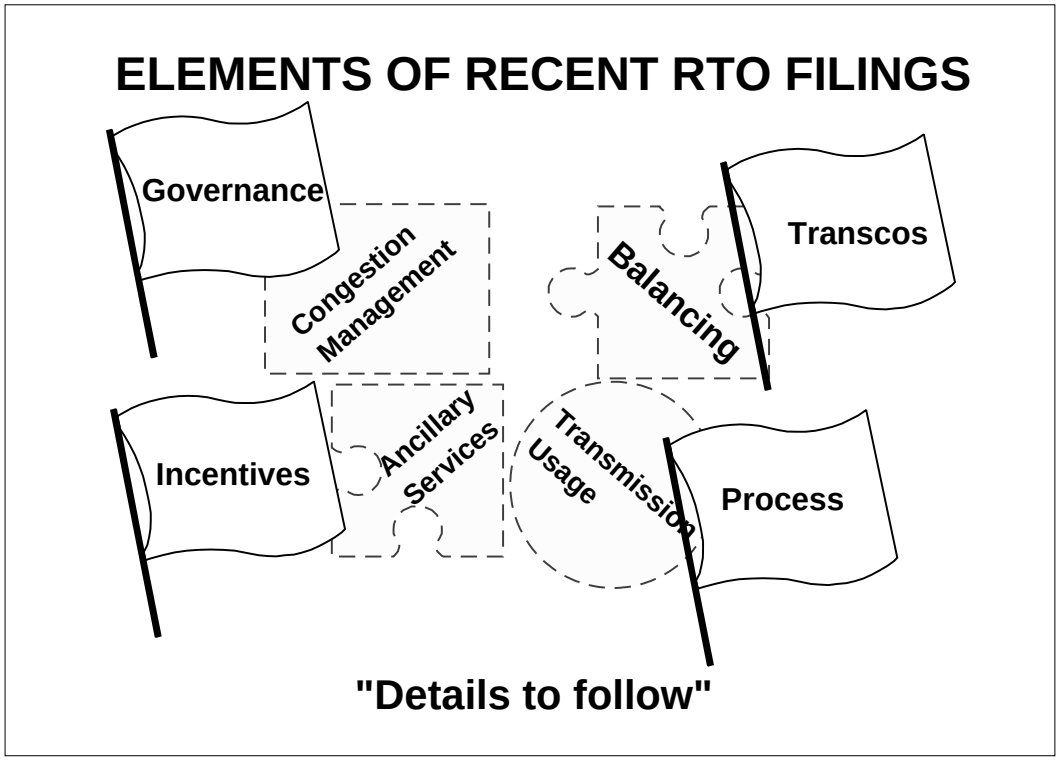
The breadth of application and success of the framework dispel the notion that the model is too complex to be implemented. We now have both the theory and substantial operating experience.

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.

ESSENTIAL ELEMENTS OF INTEGRATED MARKET DESIGN



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 RTO proposals blend alternative market models. 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 that could, in principle, be treated separately. The distinction is between what is appropriate as a basis for the design of an RTO, and what would be appropriate as the design of a stand alone business offering a service within the framework of an RTO.

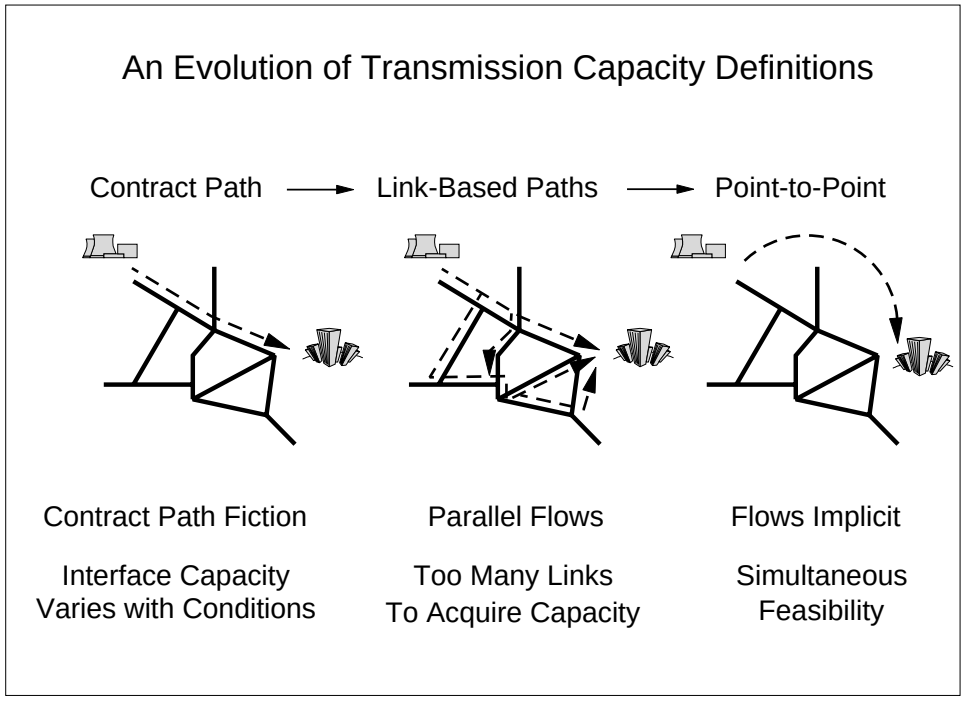
Aggregation of many locations into a few congestion zones creates problems when market participants have choices. In general, zonal pricing is not consistent with market opportunity costs. The costs of transmission congestion can be very high, and failure to internalize these costs can disrupt the energy 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.

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 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. Trading of capacity rights would take place in decentralized forward markets. Transactions that had assembled all the capacity rights needed would then be scheduled without further congestion charges. Real-time operations would be handled somehow, typically not specified as part of the flowgate model.

If the simplifying assumptions are approximately true, they present a case for a business venture, not an argument for the design of the regional transmission organization.

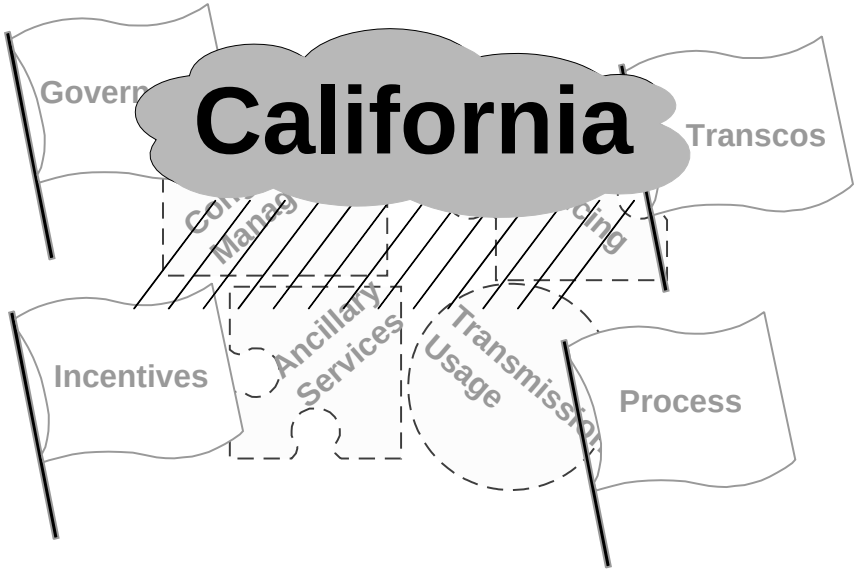
Congestion Zones: The differences in nodal prices may be small, most of the time, and the occasional excursions would not be commercially significant. Or, to be more precise, the occasional excursions would not be significant as long as the system operator did not socialize the costs. Under these circumstances, there is a clear business opportunity.

Flowgates: Under the simplifying assumptions of the flowgate model, it would be possible to decompose these point-to-point financial transmission rights into their component flowgates, implied flow capacities on flowgates, and the associated PTDFs. If the approximation errors of the flowgate model are not large, then it would be possible for a new business to provide the service of organizing trading of flowgate rights that could be reconfigured to create new FTRs. The differences in flows and capacities might be small, most of the time, and the occasional excursions would not be commercially significant. Or, to be more precise, the occasional excursions would not be significant as long as the system operator did not socialize the costs. Under these circumstances, there is a clear business opportunity.

When viewed from this perspective, the arguments in favor of congestions zones and the flowgate approach should not be seen as applying to the RTO. When the RTO follows this path, trouble is likely to appear because the real system is more complicated. Rather, the arguments for the approximations should be seen as either wrong or right. If wrong, they should be ignored. If right, they should lead to a successful business. But the simplified model is likely to be a problematic market design for an RTO.

Hanging over all this is the cloud of the crisis in California. The problems are occupying a great deal of time. The precedents will affect speed and the content of RTO developments elsewhere.

THE CLOUD ON EVERYONE'S HORIZON



The FERC proposals are too little and it is too late for such spare direction.[1]

The initial actions include:

- the elimination of the requirement that the three investor-owned utilities (IOUs) ... must sell into and buy from the PX;
- the addition of a penalty charge for deviations in scheduling in excess of five percent of an entity's hourly load requirements and the disbursement of penalty revenues to the loads that scheduled accurately;
- the establishment of independent, non-stakeholder Governing Boards for the PX and the ISO;
- the establishment of generation interconnection procedures; and
- a new form of "soft" price cap at $150.

Further, the Commission identified a number of structural reforms that must be addressed, including:

- the submission of a congestion management redesign proposal;
- possible changes to the auction mechanisms;
- improved market monitoring and market mitigation strategies;
- demand response programs by the ISO and Scheduling Coordinators;
- elimination of the requirement for balanced schedules; and
- new approach to reserve requirements.

[1] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 5.

The FERC needs to take a proactive role if anything is going to be accomplished. Consider the comments from the Federal Trade Commission staff:

> "In our view, the ISO/RTO reformation process in California and elsewhere is sufficiently advanced to benefit from more positive guidance from FERC in the form of benchmark examples of successful RTO design elements. For instance, in our August 1999 comment in FERC's RTO rulemaking proceeding, we identified locational marginal pricing (LMP) as a potential benchmark for how to price transmission congestion effectively. ...
>
> Providing positive benchmark examples also may avoid diversion of public attention to proposals that are highly unlikely to facilitate effective competition. By putting forward benchmark examples, FERC would encourage proposals in California that start from an acceptable base, not from the lowest common denominator among stakeholders."[2]

[understate, *v.t.* and *v.i.*; understated, *pt.*, *pp.*; understating, *ppr.* to make a weaker statement (of) than is warranted by truth, accuracy, or importance; to state (something) too weakly or moderately.**]**

[2] Federal Trade Commission, "Comment of the Staff of the Bureau of Economics and of Policy Planning of the Federal Trade Commission," FERC, Docket nos. EL00-95-000, Washington DC, November 22, 2000, pp. 7-8.

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:[3]

- 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.

[3] 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.

The simplified alternative market models at best are distractions, and at worst are proven failures.

Congestion Zones: Either they don't matter or they don't work.

Flowgates: Developers of flowgate models eventually acknowledge that balancing and congestion management must, in the end, be done with a bid-based, security constrained, economic dispatch with locational prices. For RTO design, the flowgates are a distraction.

"It is in public interest to improve the design and operation of short-term electricity markets. Once done, many of the other problems in the electric network would either disappear or would be greatly simplified. The problems are real, significant, and here. The Commission must address them, and will, one way or another. The best way to face the inevitable is to recognize it and do the best we can under the circumstances. The Commission knows what to do. Doing it may require using all its powers to persuade, or it may require legislation to clarify its authority to mandate. It may require both. ...

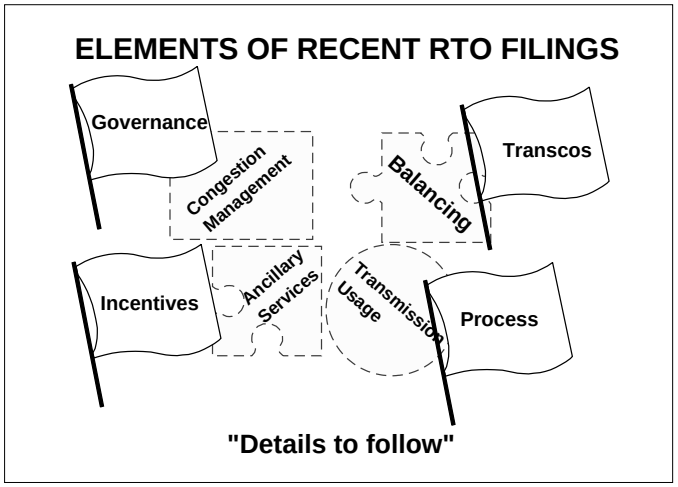
In the interest of good public policy and well functioning electricity markets, it would be best to make the voluntary approach work, soon."[4]

[4] William W. Hogan, "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems,"Center for Business and Government, Harvard University, May 2000, pp. 35-36

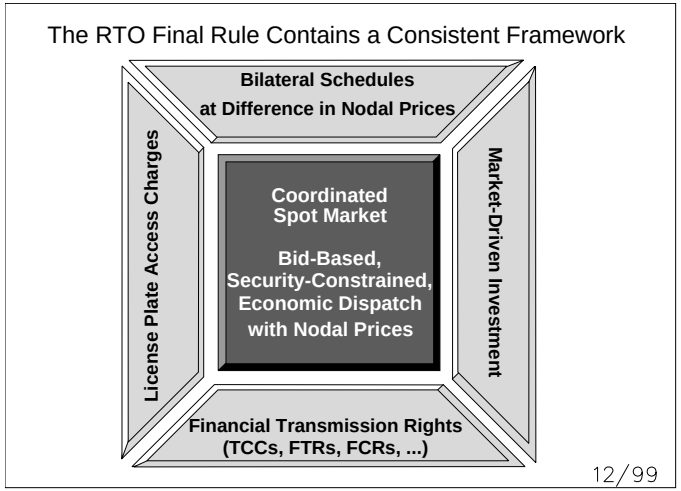
The same chronic disease is found in California and in the RTO proposals. In California the case has become acute. Time is running out. The same medicine would work for the acute case and the chronic sufferers. The FERC is on target. However, the success of the RTO Millennium Order depends on two big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

- **If FERC means what it says.** ...
- **If FERC follows through.** ...

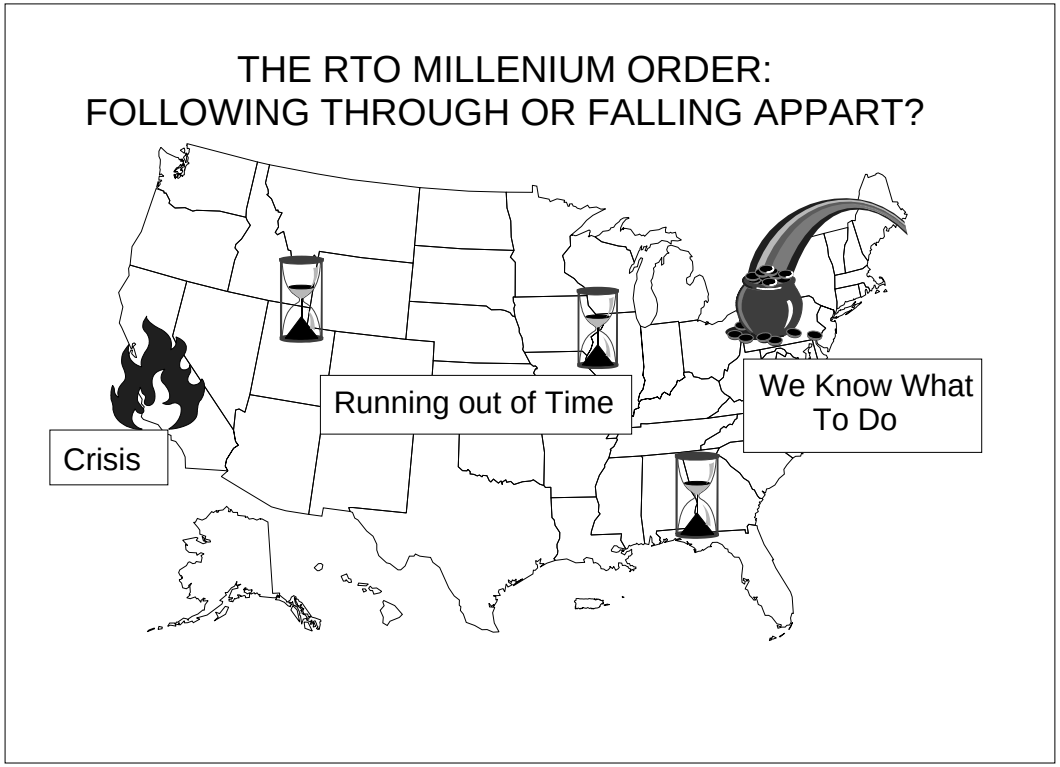
PLACEBOS



MAXIMUM STRENGTH, CLINICALLY TESTED



The crisis in California and the delay everywhere else could easily cause the collapse of the RTO agenda. We know what to do. But it requires FERC to take the leadership to make it happen.



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, 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., 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).