ELECTRICITY MARKET REFORM: Right and Wrong Paths

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The case of electricity restructuring presents examples of fundamental problems that challenge regulation of markets.

- **Marriage of Engineering and Economics.**
  - **Loop Flow.**
  - **Reliability Requirements.**
  - **Incentives and Equilibrium.**

- **Devilish Details.**
  - **Market Power Mitigation.**
  - **Coordination for Competition.**

- **Jurisdictional Disputes.**
  - **US State vs. Federal Regulators.**
  - **European Subsidiarity Principle.**

The short term financial crisis and long term energy policy provide a context with a rapidly changing view of the role of government.

- **Financial Crisis Presents Conflicting Diagnoses**

  "Deregulation, or the failure of regulators to keep up with fast-moving markets, can become unbelievably costly, as we have seen."[1]

- **Going Green Implies a Major Transformation of the Electricity Sector**

  Climate change policy and the expanded focus on renewables present a fast moving array of subsidies, regulations and mandates. Focus on transmission expansion and the smart grid.

- **Electricity Restructuring is not Electricity Deregulation**

  Electricity markets with Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), the North American Electric Reliability Corporation (NERC), State Public Utility Commissions (PUCs), Public Power Authorities, and the Federal Energy Regulatory Commission (FERC) are highly regulated entities. But "failure of regulators to keep up with fast-moving markets, can become unbelievably costly, as we have seen."

The challenge of "keeping up" emphasizes the dynamic nature of the problems and the importance of understanding the fundamentals of first principles.

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[1] Francis Fukuyama, "The Fall of America, Inc.," Newsweek, October 13, 2008, p. 32.

The Federal Energy Regulatory Commission has responsibility for regulating wholesale electricity markets. The stated framework emphasizes support for competition in wholesale markets as a clear and continuing national policy:

> "While competitive markets face challenges, we should acknowledge that competition in wholesale power markets is national policy. The Energy Policy Act of 2005 embraced wholesale competition as national policy for this country. It represented the third major federal law enacted in the last 25 years to embrace wholesale competition. To my mind, the question before the Commission is not whether competition is the correct national policy. That question has been asked and answered three times by Congress.
>
> If we accept the Commission has a duty to guard the consumer, and that competition is national policy, our duty is clear. It is to make existing wholesale markets more competitive. That is the heart of this review: to not only identify the challenges facing competitive wholesale markets but also identify and assess solutions."[2]

A task for regulation is to support this policy framework while developing hybrid markets and dealing with both the limits of markets and the failures of market designs.

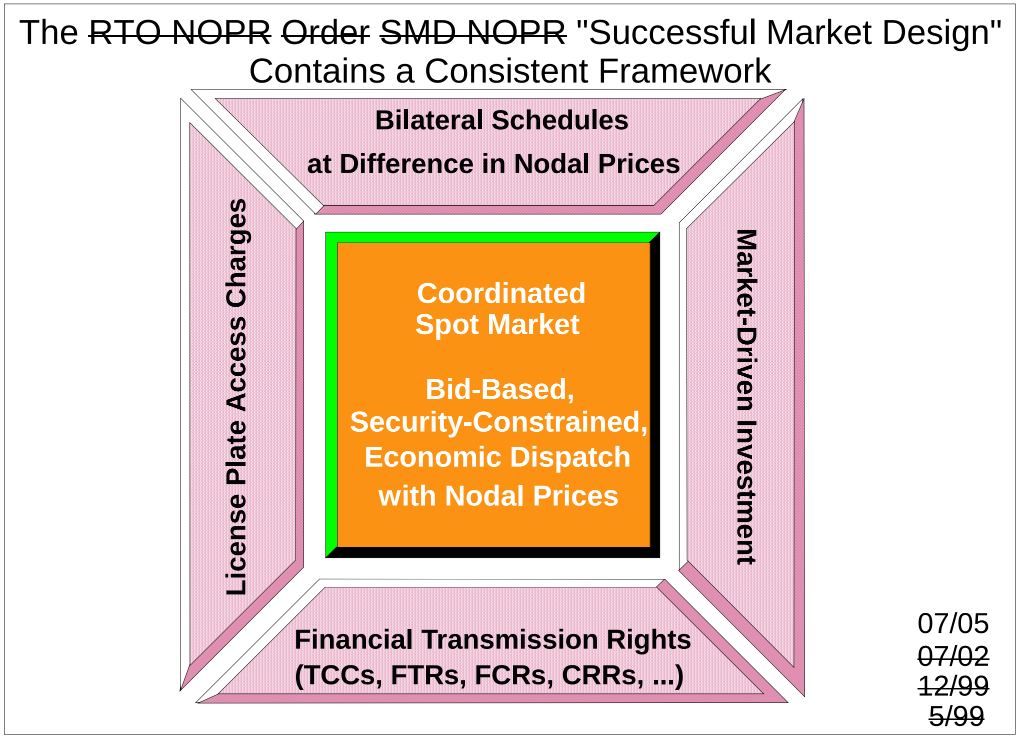
[2] Joseph T. Kelliher, "Statement of Chairman Joseph T. Kelliher," Federal Energy Regulatory Commission, Conference on Competition on Wholesale Power Markets AD07-7-000. February 27, 2007.

The focus on the electricity sector's role in addressing climate change through improved efficiency, development of renewable energy, and use of low carbon fuels creates expanded demands for and of electricity restructuring.

The transformation envisioned is massive, long term, and affects every aspect of electricity production and use.

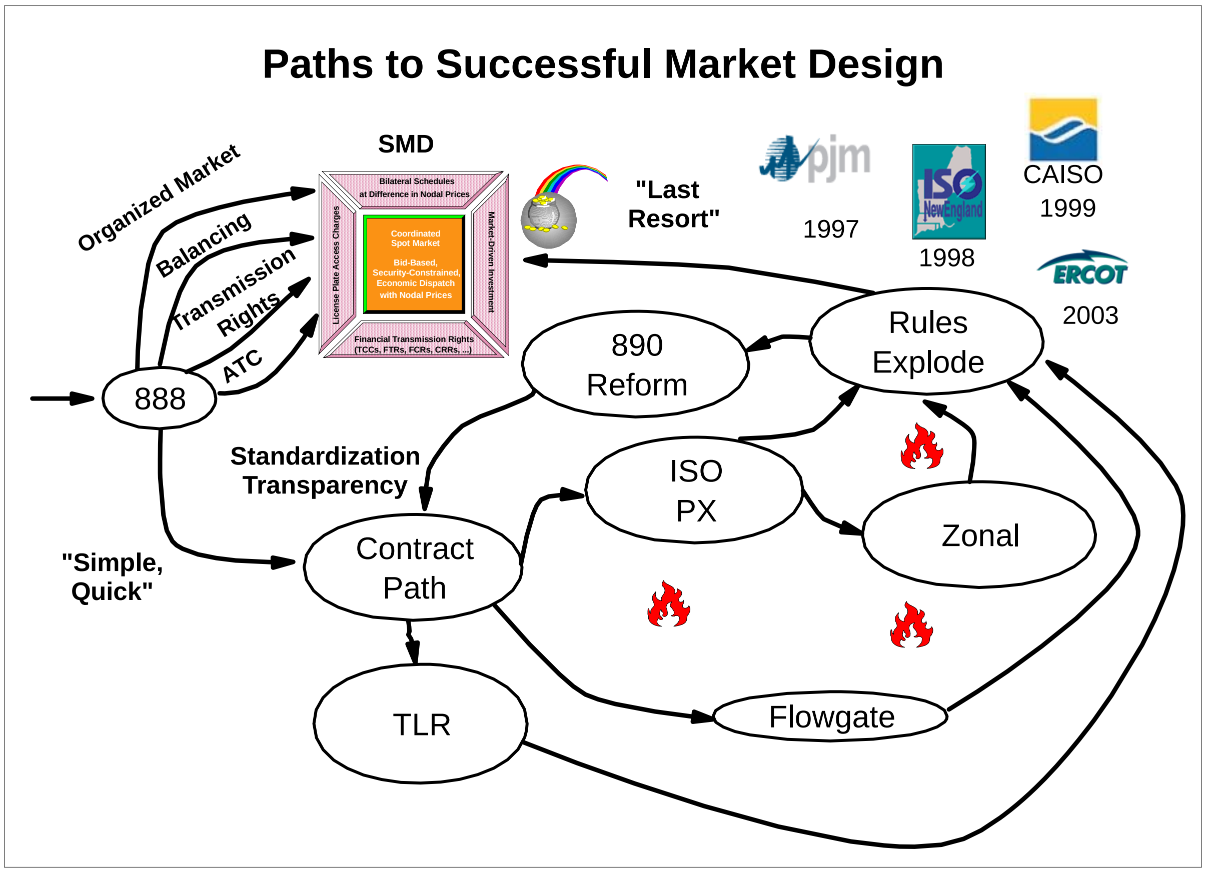
- Uncertain conditions require a broad range of activities to integrate new technology and practices.
- Innovation requires promoting technologies and practices not yet identified or imagined.
- Smart grids can facilitate smart decisions, but only if the electricity structure provides the right information and incentives.
  - Open access to expand entry and innovation.
  - Smart pricing to support the smart grid technologies and information.
  - Internalizing externalities, while exploiting the wisdom of crowds.
    - Price on carbon emissions.
    - Good market design with efficient prices.
    - Compatible infrastructure expansion rules.

The example of successful central coordination, ~~CRT, Regional Transmission Organization (RTO) Millennium Order (Order 2000)~~ ~~Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR),~~ "Successful Market Design" provides a workable market framework that is working in places like New York, PJM in the Mid-Atlantic Region, New England, the Midwest, and California.

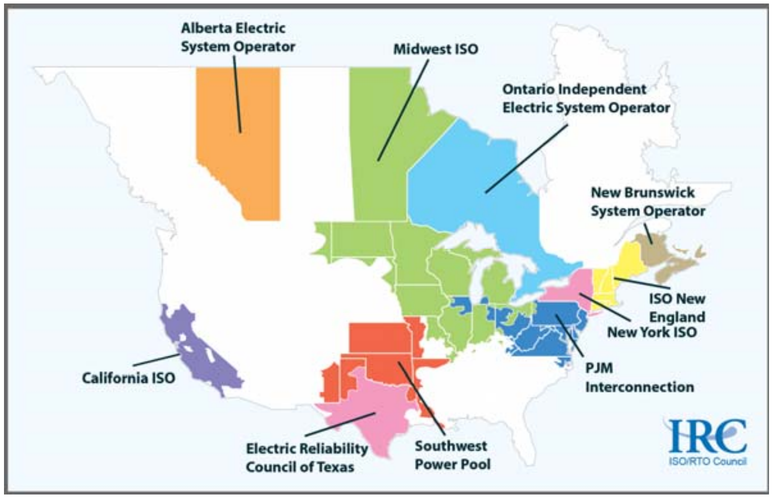


Poolco…OPCO…ISO…IMO…Transco…RTO… ITP…WMP…: "A rose by any other name …"

The path to successful market design can be circuitous and costly. The FERC "reforms" in Order 890 illustrate "path dependence," where the path chosen constrains the choices ahead. Early attempts with contract path, flowgate and zonal models led to design failures in PJM (`97), New England (`98), California (`99), and Texas (`03). Regional aggregation creates conflicts with system operations. Successful market design integrates the market with system operations.



Market design in RTOs/ISOs is well advanced but still incomplete.[3]



- **Regional Markets Not Fully Deployed**

- **Reforms of Reforms**

  California MRTU (April 1, 2009) and forthcoming ERCOT Texas Nodal reforms.

- **Market Defect: Scarcity Pricing**

  Smarter pricing to support operations, infrastructure investment and resource adequacy.

- **Market Failure: Transmission Investment**

  - Regulatory mandates for lumpy transmission mixed with market-based investments.
  - Design principles for cost allocation to support a mixed market (i.e., beneficiary pays).

- **Market Challenge: Address Requirements for Climate Change Policy**

3 William W. Hogan, "Electricity Market Structure and Infrastructure," Conference on Acting in Time on Energy Policy, Harvard University, September 18-19, 2008. (available at www.whogan.com).

The public policy debate over reshaping the electricity industry confronts major challenges in balancing public interests and reliance on markets.

The International Energy Agency (IEA) examined the international experience and produced guidance for electricity restructuring.

- "Governments must ensure a stable and competitive investment framework that sufficiently rewards adequate investments in a timely manner. …
- Governments urgently need to reduce investment risks by giving firmer and more long-term direction on climate change abatement policies. …
- Governments should pursue the benefits of competitive markets to allow for more efficient and more transparent management of investment risks. …
- Governments need to ensure that independent regulators and system operators establish transparent market rules that are clear, coherent and fair. …
- Governments must refrain from price caps and other distorting market interventions. …
- Governments must implement clearer and more efficient procedures for approval of new electricity infrastructure. …"[4]

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[4] International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, pp. 15-25.

The International Energy Agency identified the centerpiece of successful market design.

> "Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments."[5]

[5] International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, p. 16.

Application of the broad goals identified by the IEA would be compatible with recommendations by Paul Joskow for a new Federal Power Act.

"What provisions might a Federal Power Act of 2009 contain?

- [Federalize transmission] …
- [Mandate Regional Transmission Organizations] The key provisions of FERC Order 2000 should be put into law. This would require the creation of RTOs that manage the operation of large regional transmission networks, implement FERC's transmission access, pricing, and planning regulations, and operate voluntary wholesale markets for electric energy, ancillary services, capacity and transmission rights. There is abundant evidence (a) that RTOs are needed to support efficient competitive markets, (b) that expanding the geographic expanse of RTOs and improving the market designs for energy, ancillary services and capacity lead to efficiency improvements, (c) and that wholesale market designs built around what is generally referred to as the "standard market design," augmented by capacity obligations and capacity markets, promote economic efficiency.
- [Unbundle generation and distribution] …
- [States determine retail access] …
- [Limit generation subsidies to merchant investments] …
- [Allocate any free CO2 allowances to electricity consumers] …
- [State regulatory jurisdiction continue over distribution facilities] …" [6]

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[6] Paul Joskow, "Challenges For Creating A Comprehensive National Electricity Policy," Technology Policy Institute Keynote Speech, Washington DC, September 26, 2008. (available at http://www.hks.harvard.edu/hepg/).

The US experience illustrates successful market design and remaining challenges for both theory and implementation.

- **Design Principle: Integrate Market Design and System Operations**

  Provide good short-run operating incentives.
  Support forward markets and long-run investments.

- **Design Framework: Bid-Based, Security Constrained Economic Dispatch**

  Locational Marginal Prices (LMP) with granularity to match system operations.
  Financial Transmission Rights (FTRs).

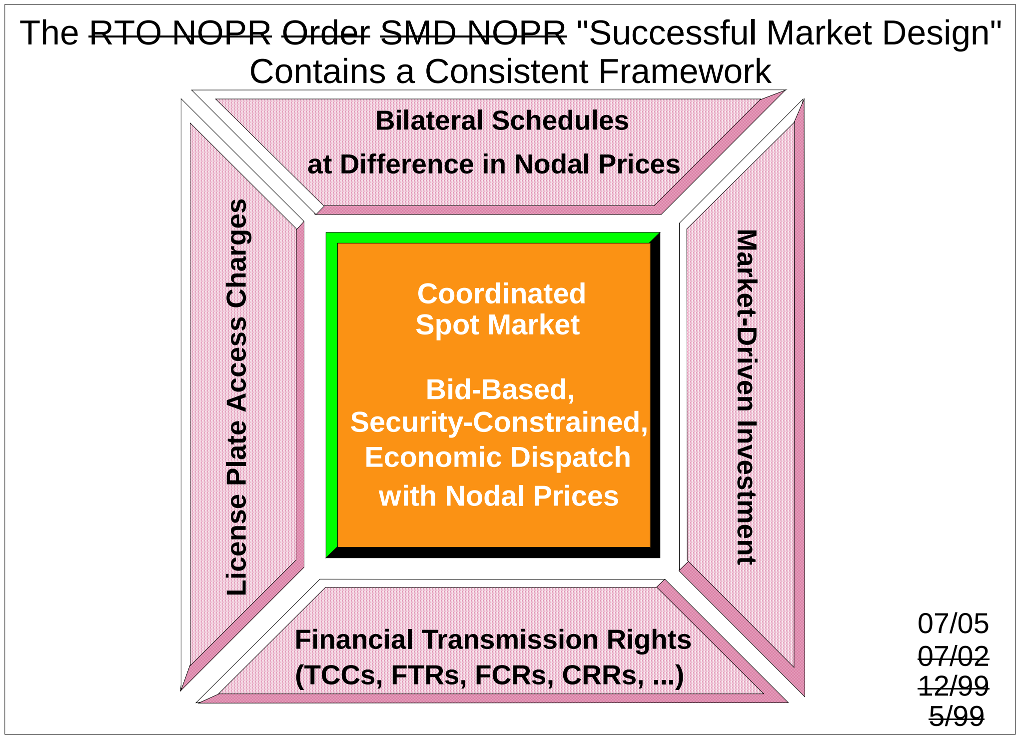
- **Design Implementation: Pricing Evolution**

  Better scarcity pricing to support resource adequacy.
  Unit commitment and lumpy decisions with coordination, bid guarantees and uplift payments.

- **Design Challenge: Infrastructure Investment**

  Hybrid models to accommodate both market-based and regulated investments.
  Applying beneficiary-pays principle to support integration with rest of the market design.

The example of successful central coordination, ~~CRT, Regional Transmission Organization (RTO) Millennium Order (Order 2000)~~ ~~Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR),~~ “Successful Market Design” provides a workable market framework that is working in places like New York, PJM in the Mid-Atlantic Region, New England, the Midwest, and California.



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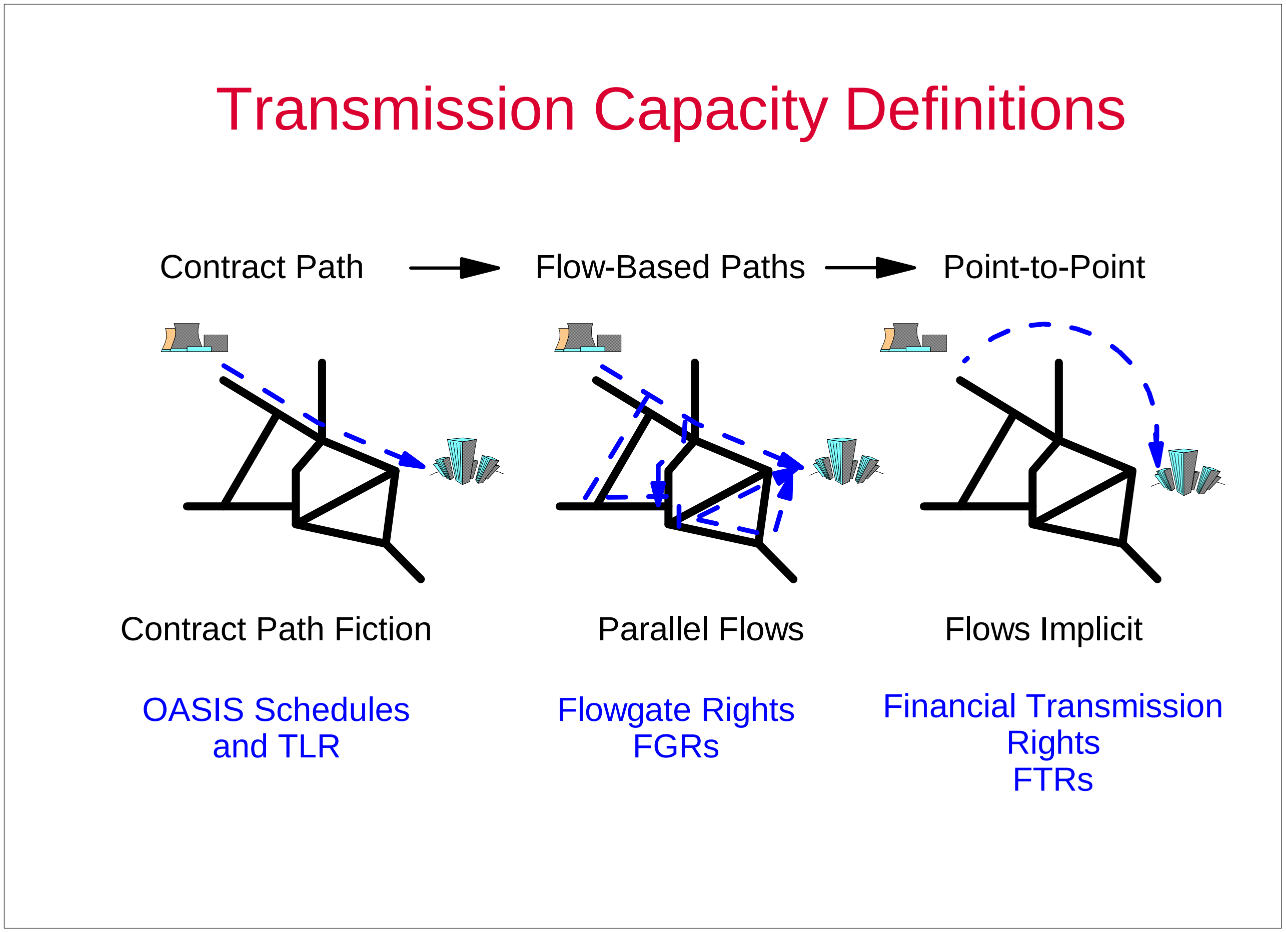
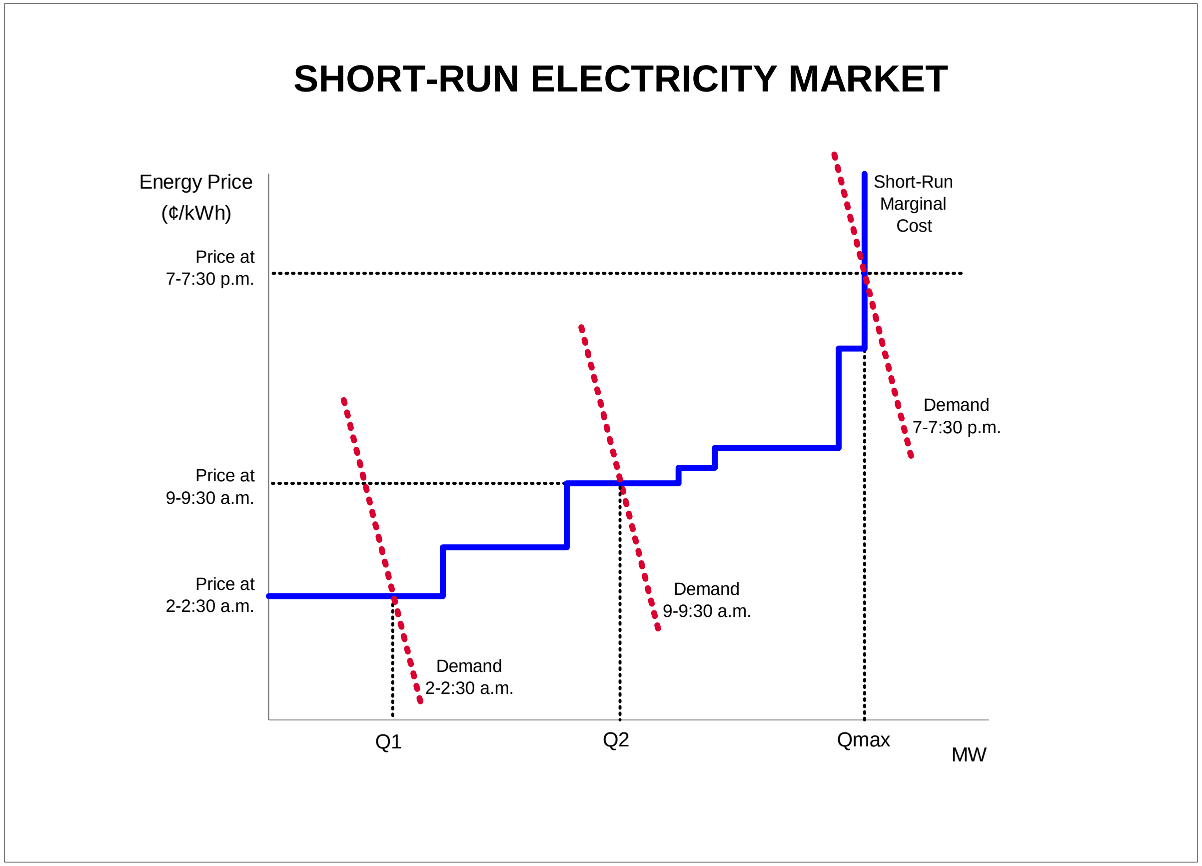
Defining and managing transmission usage is a principal challenge in electricity markets.



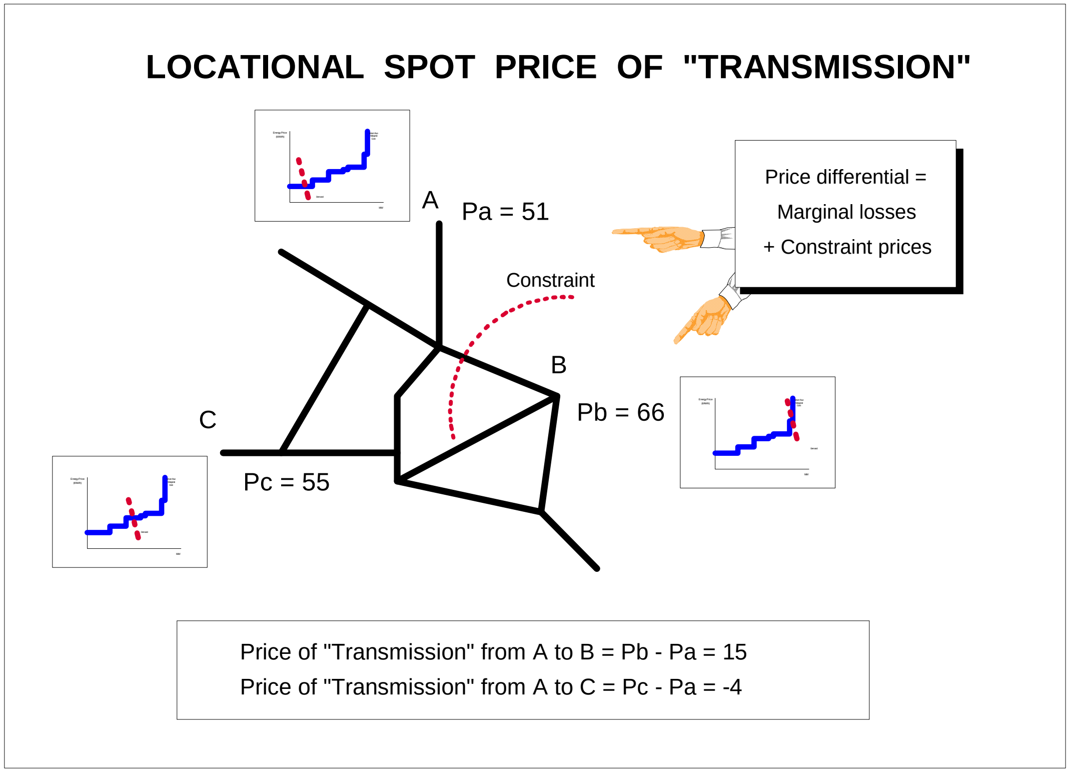
An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand. Everyone pays or is paid the same price.



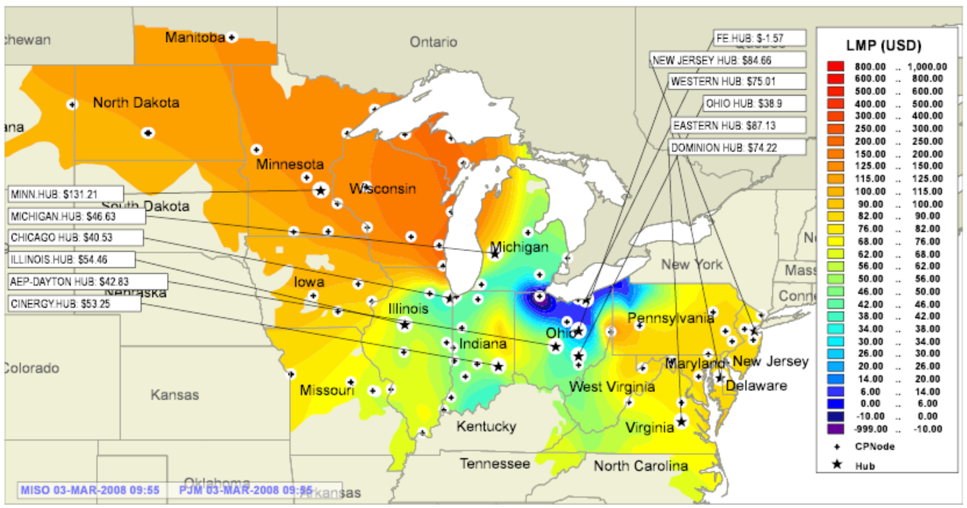
The natural extension of a single price electricity market is to operate a market with locational spot prices.

- It is a straightforward matter to compute "Schweppe" spot prices based on marginal costs at each location.

- Transmission spot prices arise as the difference in the locational prices.



RTOs operate spot markets with locational prices. For example, PJM updates prices and dispatch every five minutes for over 8,000 locations. Locational spot prices for electricity exhibit substantial dynamic variability and persistent long-term average differences.



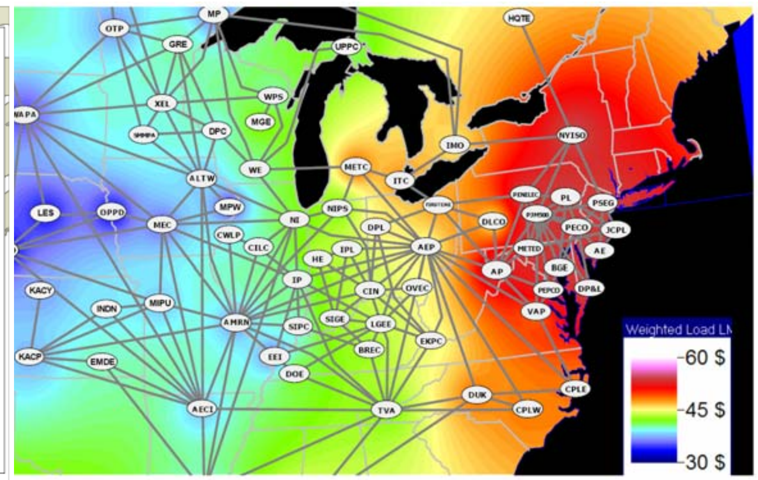


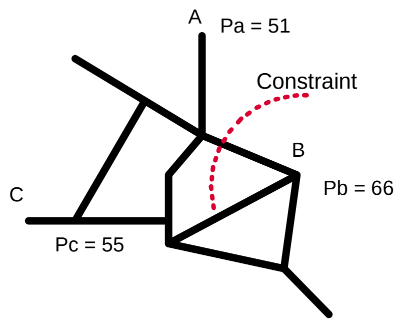
Figure 2.2-3 Contour Map of Annual Load Weighted LMP

Minnesota Hub: $131.21/MWh. First Energy Hub: $-1.57/MWh.

From MISO-PJM Joint and Common Market, http://www.jointandcommon.com/ for March 3, 2008, 9:55am. Projected 2011 annual average from 2006 Midwest ISO-PJM Coordinated System Plan.

A mechanism for hedging volatile transmission prices can be established by defining financial transmission rights to collect the congestion rents inherent in efficient, short-run spot prices.

NETWORK TRANSMISSION FINANCIAL RIGHTS



Price of "Transmission" from A to B = Pb - Pa = 15
Price of "Transmission" from A to C = Pc - Pa = -4

- DEFINE TRANSMISSION CONGESTION CONTRACTS BETWEEN LOCATIONS.
- FOR SIMPLICITY, TREAT LOSSES AS OPERATING COSTS.
- RECEIVE CONGESTION PAYMENTS FROM ACTUAL USERS; MAKE CONGESTION PAYMENTS TO HOLDERS OF CONGESTION CONTRACTS.
- TRANSMISSION CONGESTION CONTRACTS PROVIDE PROTECTION AGAINST CHANGING LOCATIONAL DIFFERENCES.

Financial Transmission Rights (FTRs), including Transmission Congestion Contracts (TCCs) and Congestion Revenue Rights (CRRs), present a variety of issues.

- **Definitions.**
  - Duration.
  - Obligations vs. Options.
  - Auction Revenue Rights.
  - Sequential Markets.
  - Expansion Rules.

- **Revenue Adequacy.**
  - Theory: Simultaneous Feasibility Ensures Full Funding with Same Grid.
  - Practice: Carve Outs, Outages and Loop Flow Forecasts can Affect Feasibility.

- **Market Performance.**
  - Arbitrage and FTR Prices.
  - Gaming and Credit Risks.
  - Market Power Interactions.

- **Investment and Trading.**
  - Grid Expansion.
  - Continuous Trading: Nodal Exchange.
    (http://www.nodalexchange.com/about_nodal/overview.php)

Scarcity pricing presents an important challenge for Regional Transmission Organizations (RTOs) and electricity market design. Simple in principle, but more complicated in practice, inadequate scarcity pricing is implicated in several problems associated with electricity markets.

- **Investment Incentives.** Inadequate scarcity pricing contributes to the "missing money" needed to support new generation investment. The policy response has been to create capacity markets. Better scarcity pricing would reduce the challenges of operating good capacity markets.

- **Demand Response.** Higher prices during critical periods would facilitate demand response and distributed generation when it is most needed. The practice of socializing payments for capacity investments compromises the incentives for demand response and distributed generation.

- **Renewable Energy.** Intermittent energy sources such as solar and wind present complications in providing a level playing field in pricing. Better scarcity pricing would reduce the size and importance of capacity payments and improve incentives for renewable energy.

- **Transmission Pricing.** Scarcity pricing interacts with transmission congestion. Better scarcity pricing would provide better signals for transmission investment.

Smarter scarcity pricing would mitigate or substantially remove the problems in all these areas. While long-recognized, the need for smarter prices for a smarter grid promotes interest in better theory and practice of scarcity pricing.[7]

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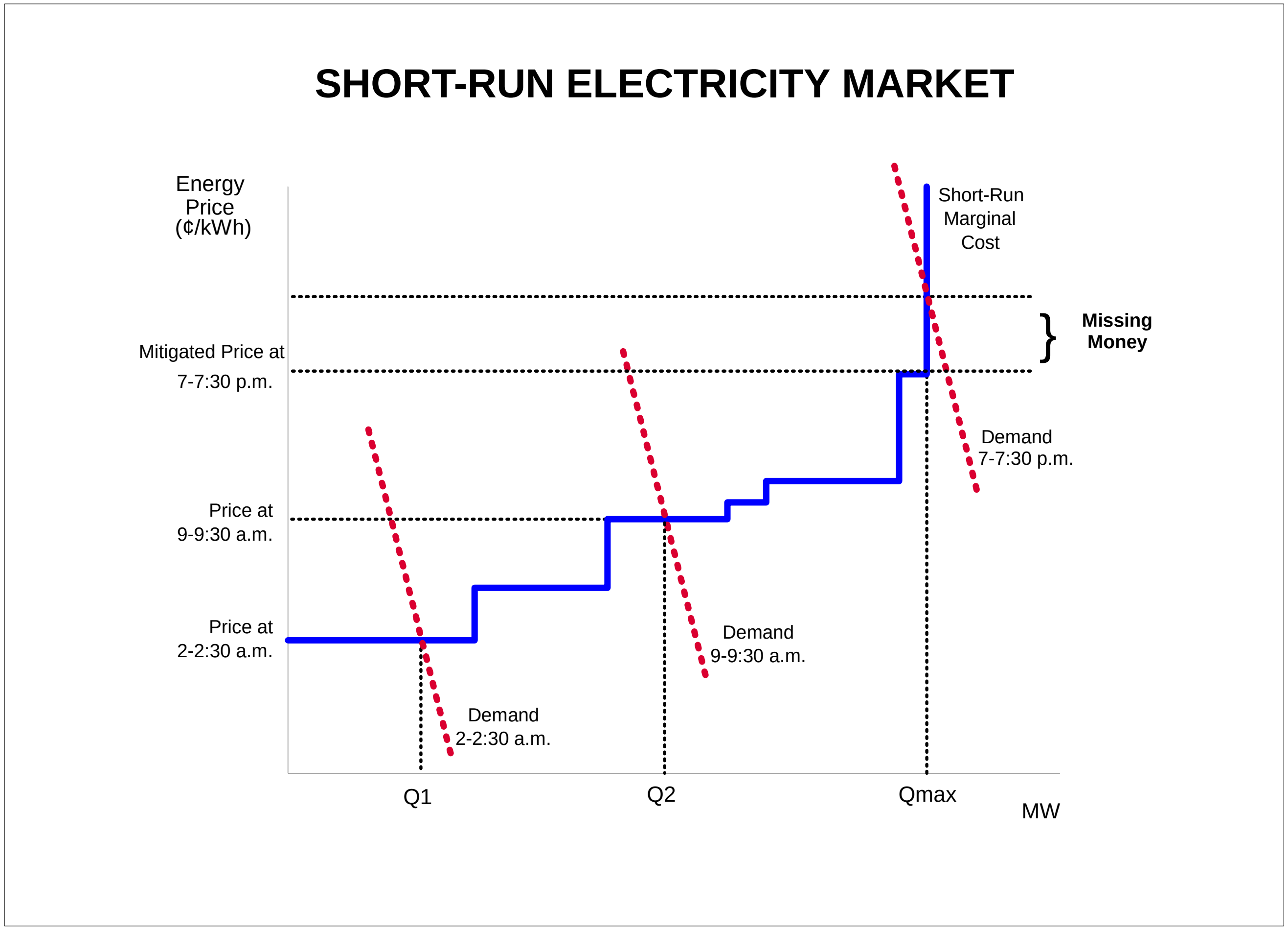
[7] FERC, Order 719, October 17, 2008.

Early market designs presumed a significant demand response. Absent this demand participation most markets implemented inadequate pricing rules equating prices to marginal costs even when capacity is constrained. This produces a "missing money" problem.



The theory and practice of scarcity pricing intersect important elements of electricity systems and economic dispatch.

- **Reliability.** By definition, scarcity conditions arise when the system is constrained and dispatch is modified to respect reliability constraints.
- **Dispatch.** Simultaneous optimization of energy and reserves means that scarcity in either effects prices for both.
- **Resource Adequacy.** The standards for resource adequacy and operating security are not fully integrated or compatible.

A critical connection is the treatment of operating reserves and construction of operating reserve demand curves. The basic idea of applying operating reserve demand curves is well tested and found in operation in important RTOs.

- **NYISO.** See NYISO Ancillary Service Manual, Volume 3.11, Draft, April 14, 2008, pp, 6-19-6-22.
- **ISONE.** FERC Electric Tariff No. 3, Market Rule I, Section III.2.7, February 6, 2006.
- **MISO.** FERC Electric Tariff, Volume No. 1, Schedule 28, January 22, 2009.[8]

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8 "For each cleared Operating Reserve level less than the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price shall be equal to the product of (i) the Value of Lost Load ("VOLL") and (ii) the estimated conditional probability of a loss of load given that a single forced Resource outage of 100 MW or greater will occur at the cleared Market-Wide Operating Reserve level for which the price is being determined. … The VOLL shall be equal to $3,500 per MWh." MISO, FERC Electric Tariff, Volume No. 1, Schedule 28, January 22, 2009, Sheet 2226.

Improved pricing through an explicit operating reserve demand curve raises a number of issues.

Demand Response: Better pricing implemented through the operating reserve demand curve would provide an important signal and incentive for flexible demand participation in spot markets.

Price Spikes: A higher price would be part of the solution. Furthermore, the contribution to the "missing money" from better pricing would involve many more hours and smaller price increases.

Practical Implementation: The NYISO and ISONE implementations dispose of any argument that it would be impractical to implement an operating reserve demand curve. The only issue is the level of the appropriate price.

Operating Procedures: Implementing an operating reserve demand curve does not require changing the practices of system operators. Reserve and energy prices would be determined simultaneously treating decisions by the operators as being consistent with the adopted operating reserve demand curve.

Multiple Locations: Transmission limitations mean that there are locational differences in the need for and efficacy of operating reserves. This would continue to be true with different demand curves for different locations.

Multiple Reserves: The demand curve would include different kinds of operating reserves, from spinning reserves to standby reserves.

Reliability: Market operating incentives would be better aligned with reliability requirements.

Market Power: Better pricing would remove ambiguity from analyses of high prices and distinguish (inefficient) economic withholding through high offers from (efficient) scarcity pricing derived from the operating reserve demand curve.

Hedging: The Basic Generation Service auction in New Jersey provides a prominent example that would yield an easy means for hedging small customers with better pricing.

Increased Costs: The higher average energy costs from use of an operating reserve demand curve do not automatically translate into higher costs for customers. In the aggregate, there is an argument that costs would be lower.

An outline of the Argentine experience bears directly on the debate in the United States and elsewhere. (For details, see Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part I: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, pp. 27-28.)

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing.

- **Expansion of Transmission Capacity by Contract Between Parties**. Allowed merchant transmission with voluntary participant funding.

- **Minor Expansions of Transmission Capacity (<$2M)**. Included regulated investment with assignment of cost, either through negotiation or allocation to beneficiaries as determined by regulator, with mandatory participant funding.

- **Major Expansions of Transmission by "Public Contest" Method**. Overcame market failure without overturning markets.
    - Regulator applies the "Golden Rule" (the traditional Cost-Benefit Test).
    - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents.
    - Assignment of costs to beneficiaries with mandatory participant funding under "area of influence" methodology.
    - No award of Financial Transmission Rights!
    - Allocation of accumulated congestion rents to reduce cost of construction ("Salex" funds).

What impact did the Argentine approach have on transmission investment?

"To illustrate the change in emphasis on investment, over the period 1993 to 2003 the length of transmission lines increased by 20 per cent, main transformers by 21 per cent, compensators by 27 per cent and substations by 37 per cent, whereas series capacitors increased by 176 per cent. As a result, transmission capacity limits increased by 105 per cent, more than sufficient to meet the increase in system demand of over 50 per cent." (Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part II: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, p. 56.)

Lessons

- **Transmission investment could be compatible with SMD incentives.**
- **Beneficiaries could be defined.**
- **Participant funding could support a market.**
- **Award of FTRs or ARRs would be an obvious enhancement.**

RTOs in the US are struggling with the development of an adequate infrastructure investment policy. A major innovation appears in the New York ISO tariff that embraces the principles of the Argentine model.

> "The proposed cost allocation mechanism is based on a "beneficiaries pay" approach, consistent with the Commission's longstanding cost causation principles. … Beneficiaries will be those entities that economically benefit from the project, and the cost allocation among them will be based upon their relative economic benefit. … The proposed cost allocation mechanism will apply only if a super-majority of a project's beneficiaries agree that an economic project should proceed. The super-majority required to proceed equals 80 percent of the weighted vote of the beneficiaries associated with the project that are present at the time of the vote."[9]

- **Beneficiaries pay.**
- **Participant funded expansions included.**
- **Regulated investment supported subject to super majority voting.**
- **Expansions awarded incremental FTRs.**

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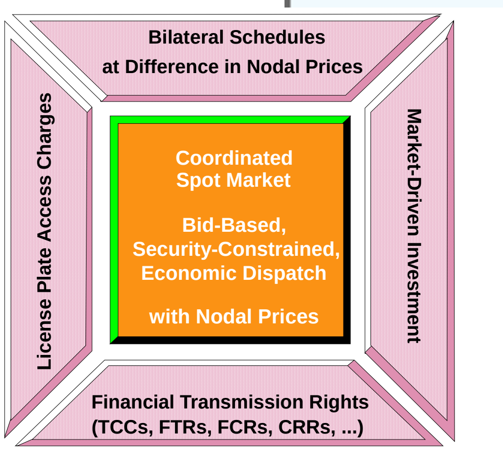
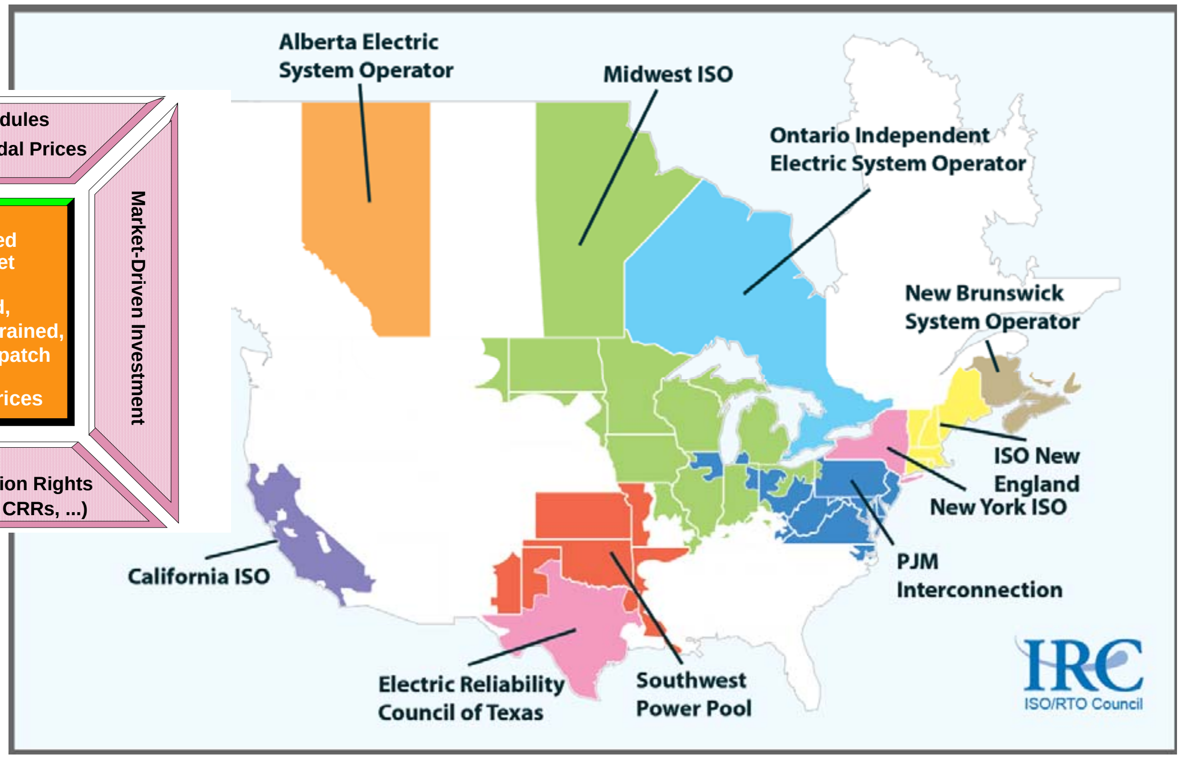
9 New York Independent System Operator, Inc Docket No. OA08-13-000, "Order No. 890 Transmission Planning Compliance Filing," Cover Letter Submitted to Federal Energy Regulatory Commission, December 7, 2007, pp. 14-15.

Regional transmission organizations (RTOs) and independent system operators (ISOs) have grown to cover over two-thirds of US economic activity.





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