Commissioner Jeff Davis

Missouri Public Service Commission

REGIONAL TRANSMISSION AUTHORITIES:

Trading Electricity Throughout the U.S. and Canada

September 21, 2010

Public Utility Basics:

- **A utility is commonly thought of as having three major operational functions:**
  - Distribution . . .
  - Generation . . .
  - Transmission . . .
- But there is another function – SYSTEM OPERATIONS

What do Systems Operators Do?

- Systems operators keep the lights on by…
  - Dispatching generation
  - Balancing supply and demand
  - Keeping system frequency at 60 Hz
  - Maintain voltage
  - Monitor system flows
  - Control transmission
  - Monitor contingencies
  - Handle emergencies

“Dispatch” Is Key to Maintaining Reliable Systems Operation:

- There’s virtually no “storage” of electricity, so electricity must be consumed as it is generated.
- “Dispatchers” send instructions to generators telling them how much electricity to generate at each generating location every dispatch interval – usually five minutes.
- “Hour-ahead” and “Day-ahead” markets facilitate generator and transmission operations/planning.

System Operators "Dispatch" Electricity Based on Cost:

- Operators attempt to dispatch generation economically – "Economic Dispatch."
- The least expensive generation in terms of operating and maintenance (O&M) costs dispatched first.
- O&M costs are often determined by fuel costs. Wind, solar and hydroelectric power are often dispatched first, followed by nuclear, coal and natural gas.

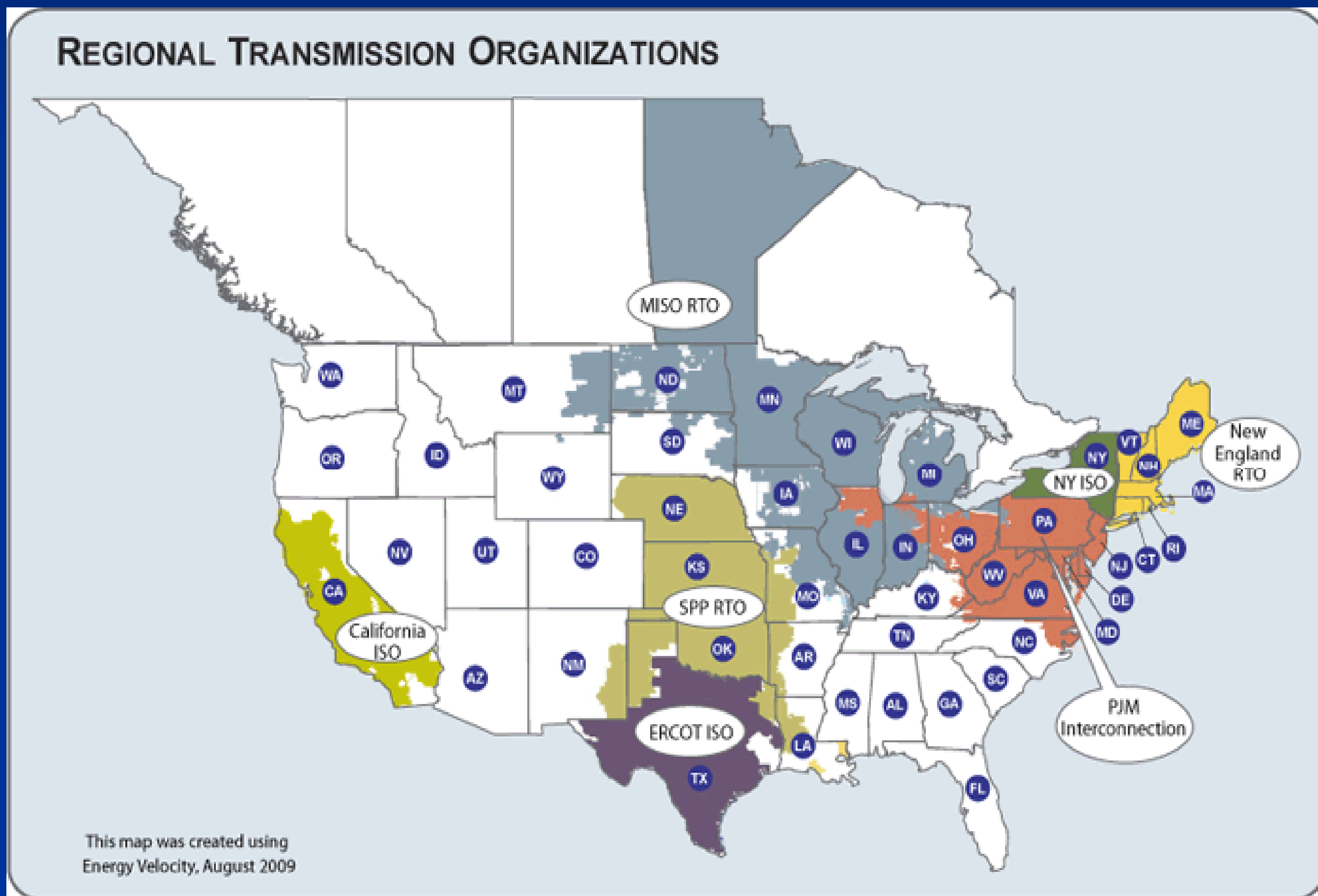
Security-Constrained Economic Dispatch:

- Transmission congestion often prevents lower cost generation from being dispatched first. Systems operators are still required to dispatch electricity based on least cost, given the constraints of the system. Thus, the term "Security Constrained Economic Dispatch."

The Rise of RTOs/ISOs:

- The Federal Energy Regulatory Commission (FERC) created regional transmission operators (RTOs) and Independent Systems Operators (ISOs) to coordinate, control and monitor the operations of the electric grid over multiple states. This includes creating a market for electricity.
- RTOs are like the European Network of Transmission System Operators (TSOs) in that they are usually larger than ISOs and operate in multiple states.

RTOs in the United States:



RTOs/ISOs:

- There are four RTOs and eight ISOs operating in North America.
- Missouri is on a seam between two RTOs:
  - the Midwestern Independent Transmission System Operator (MISO), Inc. and
  - the Southwestern Power Pool (SPP).
- A large portion of Missouri is served by rural electric cooperatives not part of any RTO.

How Electricity Gets Traded:

- There are two ways electricity gets traded:
  - Long term contracts.
  - Sales on the spot market.
- Prior to the creation of RTOs, buyers had to find each other. RTOs provide an efficient marketplace and transparency that wasn't there before.

Long Term Contracts v. Spot Market Sales

- Long term contracts provide generators with guaranteed cash flow for financing purposes. Purchasers get cost certainty. Most long term contacts now exist for the purchase of renewables whereby utilities buy all of plants output at a specified rate.
- Spot market sales, sales in the hour ahead or day ahead market are now the norm.

How the MISO market works:

- No one is forced to "buy" energy from the RTO spot markets
  - Any Load Serving Entity (LSE)/utility can self-schedule its own generation to its own loads – load is served at the LSE/utility's generation costs.
  - Any LSE/utility can schedule bilaterals to serve its own loads – load is served at the contract price of the bilateral.

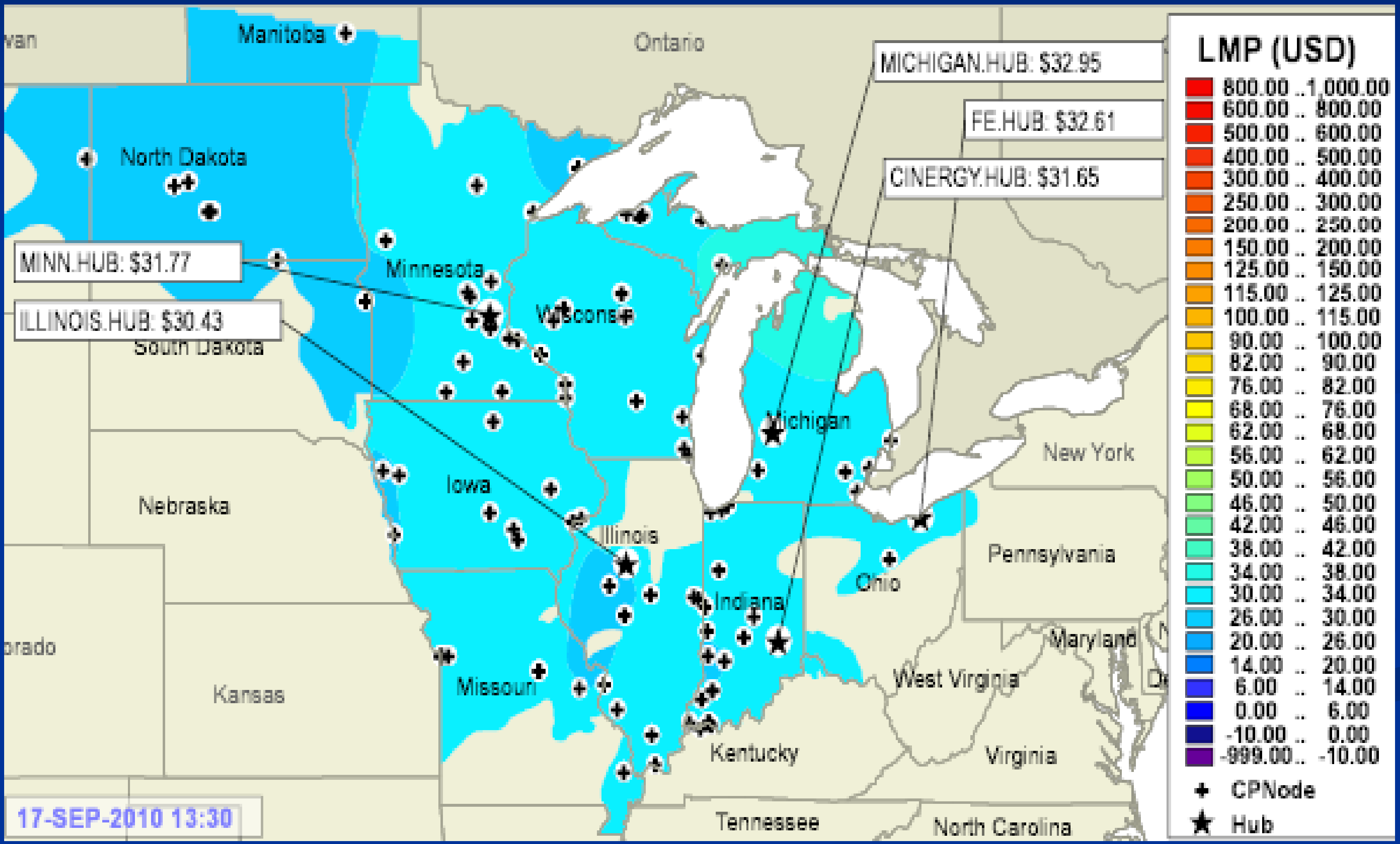
How the MISO market works:

- Parties using the spot market must accept its settlements
  - Parties that have imbalances/deviations settle at spot prices
  - Parties that buy/sell “extra” energy through the dispatch also settle at spot prices.

How the MISO market works:

- Locational Marginal Prices (LMPs) are used to determine spot market settlements.
- An LMP is *the lowest dispatch cost for serving an increment of load (1 more MW) at each location, given the available* offers/bids and the transmission limits faced by the dispatch. Phrased another way, LMP reflects the marginal cost of serving an increment of load at each location, given the dispatch, grid constraints, and the offers/bids.

MISO LMP Spot Market Prices:



LMP Allows RTOs to Redispatch Electricity To Avoid Curtailments

- LMP prices congestion redispatch at marginal cost – the change in the cost of the dispatch necessary to relieve congestion and allow a schedule to flow without curtailment.
  - Marginal cost of redispatch = MW times (LMPsink – LMPsource)
  - Marginal cost of redispatch = Transmission usage charge

Redispatching Electricity (Cont'd)

- Different LMPs allows RTOs to "redispatch electricity" or "buy through congestion" – the ability to price redispatch means the RTO can offer redispatch service at an efficient/fair price.
  - Users can choose to pay the usage charge for redispatch, or . . .
  - They can choose to be curtailed if the price is too much
  - A third choice is to hedge redispatch costs with Financial Transmission Rights (FTRs).

Financial Transmission Rights:

- FTRs entitle the holder to a rebate or credit of the congestion part of usage charges between any two locations.
  - Credit = the difference between the price at the FTR sink and the price at the FTR source (ignoring losses component).
  - FTR credit = MW times ($LMP_{sink} – LMP_{source}$)
  - FTRs are direct hedges against congestion costs
  - FTR holders can lock in the cost of congestion charges

FTRs Support Efficient Dispatch

- FTRs do not need to match actual schedules
  - Parties don't have to change/trade their FTRs just because they change their schedules, supplier or load locations
  - Parties are free to follow ISO economic dispatch instructions without changing their FTRs
- When the RTO/ISO is administering market settlements, the FTR holder receives the market value of the FTRs it holds, regardless of actual dispatch schedules

Who gets FTRs?

- Initial principle: those who pay grid fixed costs get FTRs.
  - Those who pay for network integrated service – typically LSEs
  - Those who purchase point-to-point firm service – gencos, LSEs, traders
- Applying this principle to transmission upgrades:
  - The entity that pays the costs of an upgrade receives the net incremental FTRs made feasible by the upgrade

Alternative Ways to Allocate FTRs:

- Initial allocation to those who paid the grid's fixed costs
  - This is how ISO/RTOs got started
  - Allocates the value of the grid to those who paid/pay its costs
- Periodic auctions of FTRs (or the auction revenues)
  - Allows an efficient allocation to those who value FTRs most
  - Can auction residual FTRs or all of them
  - Problem: What do we do with the auction revenues?

More Ways to Allocate FTRs:

- Auction revenue rights = ARRs = Combines both concepts – now used in MISO, PJM, NE and NY
  - From an initial FTR allocation, allocate the corresponding revenue rights
  - Hold FTR auction, then allocate the revenues to the holders of the ARRs

Transactions Recap:

- LMP/Nodal pricing provides efficient price signals for investments.
  - Nodal spot prices, and long-term contracts based on the spot prices, provide the basis for market-driven investments in new generation (or siting new loads).
  - Nodal prices signal when, how much, *and where*.
- Transmission usage charges from nodal price differences and FTR values signal the value of transmission upgrades.

Transactions Recap:

- Financial Transmission Rights (FTRs) hedge congestion costs and complete the foundation for market-driven transmission upgrades.
  - FTRs are tradable property rights that capture the value of the existing grid *and upgrades*.
  - FTR forward prices (from auctions and trades) provide long-run price signals about the value of upgrades.
- LMP/FTR pricing helps regulators find/verify cost-effective upgrades.

RTO Interconnection Agreements:

- Why have interconnection agreements between RTOs?
  - Eliminate “rate pancaking” for transmission
  - Lowers “reserve margin” – need fewer reserves
  - Volume of transactions lowers costs
  - Easier to take generators “off line” for maintenance
  - Access to cheaper generation
  - Ability to sell more electricity
  - Creates market for reserve units, ancillary services

MISO Seams Agreements:

- *Joint Operating Agreement (JOA) Between MISO And PJM Interconnection, L.L.C. December 30, 2003*
- *JOA Between MISO and SPP. December 1, 2004*
- *Joint Reliability Coordination Agreement Among And Between MISO, PJM and TVA April 22, 2005*
- *Seams Operating Agreement Between MISO and Manitoba Hydro September 25, 2006*

Typical Seams Agreement Provisions

1) Definition of key terms and acronyms
2) Define Phases:
   a) Non-Market to Non-Market
   b) Market to Non-Market
   c) Market to Market
3) Exchange Operating Data, SCADA, Models, Planning Data
4) Exchange ATC/AFC methodologies, and data inputs
5) Define and agree to manage Reciprocal Coordinated Flowgates
6) Outage Coordination
7) Joint Operations in Emergencies
8) Coordination of Transmission Planning

Seams Agreement Provisions (Cont'd)

9) Joint Scheduling Checkout Procedures

10) Voltage Control and Reactive Power Coordination

11) Dispute Resolution

12) Boilerplate Terms: Indemnity, Accounting for Costs, Confidentiality of Data, Intellectual Property, Termination, Choice of Law, etc.

13) The Congestion Management Process (CMP): Detailed attachment to each seams agreement containing technical requirements for managing market-to-non market congestion using RCFs.

Seams Agreements (Cont'd)

14) The Interregional Coordination Process (ICP): Detailed attachment to Midwest ISO-PJM seams agreement containing technical requirements for managing market-to-market congestion using RCFs but allowing each RTO to "buy through" its congestion relief obligation by paying the other RTO to redispatch when that is the cost effective solution.

Questions?

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