TRANSMISSION NETWORK CONGESTION

• Why do we care?
  – Higher generating costs as low-cost generation is “constrained off”
  – Stressed networks are less reliable
• Why does congestion emerge?
  – Thermal/physical limits on lines and transformers
  – Engineering reliability and contingency criteria (N-1, N-2, etc.)
    • How are these engineering criteria defined?
    • How do they relate to economic valuations of lost load (VOLL), priced-based demand response, rolling blackouts, and network collapse?
• How to allocate “scarce” transmission capacity with competitive G sector?
  – Alternatives to central dispatch by vertically integrated utilities
  – Non-price rationing hierarchies (intra- and inter-control area TLR protocols) with tariff-based transmission service contracts
  – Security constrained bid-based dispatch (nodal pricing) plus financial transmission rights (FTR)
  – Tradeable cost-based physical transmission rights between defined zones or “flow gates”
• How do we stimulate investment in new transmission capacity?
  – Reliability rules
  – Congestion cost reduction
  – Market power mitigation
  – Regulated transmission investment
  – Merchant transmission investment
  – Hybrid models
TRANSMISSION CONGESTION

$C_1 = C_1(q_1)$

$C_2 = C_2(q_2)$

$Q = q_1 + q_2 = D(p_2)$

$C_1' < C_2'$

$p_1^* = C_1'(K)$

$p_2^* = C_2'(D(p_2^* - K)) > p_1^*$

$q_1 = K$

$D(p_2^*) = q_1 + q_2 = K + q_2$

$\eta^* = p_2^* - p_1^*$

Joskow-Tirole
TRANSMISSION CONGESTION WITH LOOP FLOW

Node 1: Cheapgen
Cost: $C_1(q_1)$

$C_1' < C_2'$

Node 2: Deargen
Cost: $C_2(q_2)$

$1/3(q_1 - q_2) \leq K$

Node 3: Consumption
$q_3 = D(p_3)$
$p_3 = P(q_3)$

Joskow-Tirole

\[
\begin{align*}
q_1 + q_2 &= q_3 \\
1/3(q_1 - q_2) &\leq K \\
p_1 &= p_3 - \eta/3 \\
p_2 &= p_3 + \eta/3 \\
p_3 &= (p_1 + p_2)/2 \\
p_1 &= C_1'(q_1) = C_1'(q_2 + 3K) \\
p_2 &= 2P(2q_2 + 3K) - p_1
\end{align*}
\]
400 Mw
MC = 12

Bus 2
19 MW
62.3 MW
12.00 $/MWh

Bus 3
81 MW
81%
MVA

100 MW
81 MW
14.01 $/MWh

Bus 1
19 MW
10.00 $/MWh

118.7 MW

400 Mw
MC = 20

Total Cost
1934.8 $/hr
RELIABILITY AND CONTINGENCY CRITERIA

- Transmission capacity is rarely limited by thermal constraints on facilities
- Limits are typically a consequence of applying engineering reliability and contingency criteria
  - These criteria are not simple
  - They are based on a large number of assumptions about system conditions on many transmission links, generating stations and interconnected control areas
  - They can vary widely with system conditions and weather conditions
  - They can be affected by the installation of enhanced real time monitoring equipment
  - They are affected by the status of remedial action plans, information transfer and communication speeds
  - They give the system operator a lot of discretion
- These reliability and contingency criteria have been carried over from the old world of (many) regulated vertically integrated monopoly control area operators
  - There has been little evaluation of the economic rational or economic effects of these criteria
  - They affect wholesale market prices for energy
Bus 2
50.0 MW
12.00 $/MWh

Bus 3
50 MW
50 MW

Bus 1
10.00 $/MWh
50.0 MW
50 MW

Total Cost
2700.4 $/hr
Security Coordinators

NERC
DAY-AHEAD PEAK WHOLESALE ENERGY
PRICES (2004) $/MWH

MASS HUB  NY-G  NY-J  PJM-W  CINERGY
CONGESTION MANAGEMENT IN THE U.S.

• Nodal Pricing Areas
  – New England
  – New York
  – PJM
  – MISO
  – California (next year)
  – Texas (Zonal/flowgates $\rightarrow$ nodal)

• Rest of U.S.
  – Tariff-based transmission service with limited trading
  – No congestion pricing
  – Administrative rationing of scarce capacity
ISO/RTOs in the United States 2006

### Table 8: RTO Market Characteristics in 2006

<table>
<thead>
<tr>
<th>Services Provided</th>
<th>ISO-NE</th>
<th>NYISO</th>
<th>PJM</th>
<th>MISO</th>
<th>SPP</th>
<th>ERCOT</th>
<th>CAISO</th>
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</thead>
<tbody>
<tr>
<td>Bilateral transactions</td>
<td></td>
<td></td>
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<tr>
<td>Active online physical trading</td>
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<tr>
<td>Active online financial trading</td>
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<tr>
<td>Real-time energy market</td>
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<tr>
<td>Locational energy price</td>
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<tr>
<td>Hourly energy price</td>
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<tr>
<td>Congestion price</td>
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<tr>
<td>Losses price</td>
<td>07</td>
<td>07</td>
<td>07</td>
<td>07</td>
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<td></td>
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<tr>
<td>Day-ahead energy market</td>
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<td>09</td>
<td>08</td>
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<td>Locational energy price</td>
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<td>09</td>
<td>08</td>
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<tr>
<td>Hourly energy price</td>
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<td>09</td>
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<tr>
<td>Congestion price</td>
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<td>09</td>
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<tr>
<td>Losses price</td>
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<tr>
<td>Ancillary services market</td>
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<td>Regulation service market</td>
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<td>Operating reserves market</td>
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<td>Reactive power market</td>
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<td>Black start market</td>
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<td>Financial transmission rights</td>
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<tr>
<td>Capacity market</td>
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<td>Regional transmission scheduling</td>
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<td>Regional economic dispatch</td>
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<tr>
<td>Regional transmission planning</td>
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<tr>
<td>Regional interconnection process</td>
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<td>Independent market monitor</td>
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<tr>
<td>Mitigation</td>
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</tr>
</tbody>
</table>

Source: FERC 2006 State of the Markets Report
NODAL PRICING MODEL

- The nodal pricing models now work reasonably well in the Eastern ISOs from both economic dispatch and reliability perspectives
- NE, NY and PJM now include marginal losses in prices
- Congestion is managed economically and least bid-cost dispatch is achieved
- Nodal prices provide a good indication of congestion costs (except during scarcity conditions)
- Day-ahead and real-time prices are well arbitrated in an expected value sense
- Market power and gaming are more transparent than with other systems
- Coordination between ISOs is improving
  - PJM internalized through expansion and joint operating agreements with MISO
- California and Texas are moving to nodal pricing due to problems with zonal models
NON-PRICE RATIONALING

Priority of Interchange Transactions

3.1.1. Interchange Transaction curtailment priority shall be determined by the Transmission Service reserved over the constrained facility(ies) as follows:

Transmission Service Priorities

Priority 0. Next-hour Market Service — NX*
Priority 1. Service over secondary receipt and delivery points — NS
Priority 2. Non-Firm Point-to-Point Hourly Service — NH
Priority 3. Non-Firm Point-to-Point Daily Service — ND
Priority 4. Non-Firm Point-to-Point Weekly Service — NW
Priority 5. Non-Firm Point-to-Point Monthly Service — NM
Priority 6. Network Integration Transmission Service from sources not designated as network resources — NN
Priority 7. Firm Point-to-Point Transmission Service — F and Network Integration Transmission Service from Designated Resources — FN

NERC
Example
This example is based on the premise that a transaction should be curtailed in proportion to its Transfer Distribution Factor on the Constraints. Its effect on the interface is a combination of its size in MW and its effect based on its distribution factor.

<table>
<thead>
<tr>
<th>Column</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Initial Transaction</td>
<td>Interchange Transaction before the TLR Procedure is implemented.</td>
</tr>
<tr>
<td>2. Distribution Factor</td>
<td>Proportional effect of the Transaction over the constrained interface due to the physical arrangement and impedance of the transmission system.</td>
</tr>
<tr>
<td>3. Impact on the Interface</td>
<td>Result of multiplying the Transaction MW by the distribution factor. This yields the MW that flow through the constrained interface from the Transaction. Performing this calculation for each Transaction yields the total flow through the constrained interface from all the Interchange Transactions. In this case, 760 MW.</td>
</tr>
<tr>
<td>5. Weighted Maximum Interface Reduction</td>
<td>Multiplying the Impact on the Interface from each Transaction by its Impact Weighting Factor yields a new proportion that is a combination of the MW Impact on the Interface and the Distribution Factor.</td>
</tr>
<tr>
<td>6. Interface Reduction</td>
<td>Multiplying the amount needed to reduce the flow over the constrained interface (280 MW) by the normalization of the Weighted Maximum Interface Reduction yields the actual MW reduction that each Transaction must contribute to achieve the total reduction.</td>
</tr>
<tr>
<td>7. Transaction Reduction</td>
<td>Now divide by the Distribution Factor to see how much the Transaction must be reduced to yield the result calculated in Column 7. Note that the reductions for the first two Interchange Transactions (A-D (1) and A-D (2) are in proportion to their size since their distribution factors are equal.</td>
</tr>
<tr>
<td>9. Adjusted Impact on Interface</td>
<td>A check to ensure the new constrained interface MW flow has been reduced to the target amount.</td>
</tr>
</tbody>
</table>
**Example 2**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>50 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>1000 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>1000 MW − 800 MW = 200 MW</td>
</tr>
<tr>
<td>Amount to enter into IDC for Transactions using Point-to-Point Transmission Service</td>
<td>950 MW − 200 MW = 750 MW</td>
</tr>
</tbody>
</table>
Example 3

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow to maintain on Facility</td>
<td>800 MW</td>
</tr>
<tr>
<td>Expected flow next hour from Transactions using Point-to-Point Transmission Service</td>
<td>950 MW</td>
</tr>
<tr>
<td>Contribution from flow next hour from service to Network customers and Native Load</td>
<td>-200 MW</td>
</tr>
<tr>
<td>Expected Net flow next hour on Facility</td>
<td>750 MW</td>
</tr>
<tr>
<td>Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation</td>
<td>750 MW - 800 MW = -50 MW</td>
</tr>
<tr>
<td></td>
<td>None are held</td>
</tr>
</tbody>
</table>
NON-PRICE RATIONING

• Works reasonably well from a reliability perspective as long as there is good communication between SOs, between SOs and generators and generators follow instructions
• Redispatch is not necessarily efficient because it is not based on hour-ahead costs of redispatch
• TLRs continue to increase
• Continuing arguments about whether redispatch was “fair” and consistent with contracts
  – This problem is exacerbated when SO also owns generating capacity on the network
• Cost and price of congestion is not transparent
Figure 4-4. Projected Congestion on Western Transmission Paths, 2008

U90 values at alternative natural gas prices.
Figure 4-7. Existing and Projected Major Transmission Constraints in the Western Interconnection
Assumptions

- 2008 SSG-WI assumptions with increased renewables in California
- Path 49 Upgrades
  - Palo Verde-Devers #1 Series Capacitors Upgraded
  - Hassayampa-North Gila-Imperial Valley Series Capacitors Upgraded
  - 2nd Devers 500/230 kV Transformer added
  - SVC added at Devers
- Miguel-Mission 230 kV line added
- East of River limited to 8,055 MW
- West of River Unconstrained
Assumptions (continued)

• Palo Verde West limited to 3600 MW
• All 500 kV line ratings are respected
• Mohave out of service
• Mountainview, Palomar, and Otay Mesa in-service
• Additional renewables in California to meet Renewable Portfolio Standard of 20%
Sequence Studied

• Step 1: Add EOR 9000 project (Mead-Perkins and Navajo-Crystal Upgrade)
• Step 2: Add Moenkopi-Eldorado series capacitor upgrade
• Step 3: Add Palo Verde-Devers #2
EOR Path Rating Observations

- A 9,000 MW EOR rating appears to be an appropriate objective after the EOR 9000 project
- With the addition of the Moenkopi-Eldorado upgrade to the EOR 9000 project, a 9,500 MW EOR rating appears to be an appropriate objective
- With the addition of the PVD2 project, a 11,500 MW EOR rating appears to be an appropriate objective (a 2,000 MW increase)
- Qualification -- Achieving these path ratings may prove to be technically infeasible or uneconomic
TRANSMISSION INVESTMENT

- Driven by reliability criteria and economic opportunities to reduce congestion
  - These are not independent
  - Implementation of reliability criteria affect market prices
- Origins of engineering reliability criteria are opaque
  - Solutions to restore reliability criteria are complex and do not have unique solutions
  - Require interaction over entire synchronized network involving multiple SOs
- Not conducive to link-by-link merchant investments
- Regional planning and integrated assessment of reliability and economic criteria are essential
- Economic implications and justifications for reliability criteria need a fresh assessment