A SuperOPF Framework
for Improved Allocation and Valuation of System Resources through Co-optimization

Ray Zimmerman
Cornell University
rz10@cornell.edu
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Outline

➢ Background
  – What is a “SuperOPF” and why is it needed?

➢ Description of SuperOPF Framework
  – Conceptual Structure
  – Problem Formulation for Current Implementation
  – Our Contributions

➢ Applications
  – Case Study 1: Reliability
  – Case Study 2: Renewables

➢ Future Directions
Collaborators

- Alberto Lamadrid
- Surin Maneevitjit
- Timothy Mount
- Carlos Murillo-Sánchez
- Robert Thomas
- Zhifang Wang
- Hongye Wang
- Ray Zimmerman
Background Motivation

The following all depend on the ability to properly allocate and value system resources, including reliability …

- design and operation of electricity markets for energy, capacity, ancillary services, on all time scales from real-time to multi-year forward markets
- power grid operations: unit commitment, dispatch, maintenance
- regulatory oversight: market monitoring, reliability standards, impacts of environmental regulation
- resource planning: optimal investment, reliability studies, economic and reliability impacts of changes in technology (wind, solar, PHEV, DER, CHP, smart grid)
Limitations of Current Practice

- Current state-of-the-art tools break problem into sequential sub-problems and often use DC approximations & proxy constraints. (reserve margins for adequacy, flow limits for voltage)
- DC models with proxies for AC constraints may approximate optimal dispatch, but the **nodal prices are often wrong**, especially when the system is stressed.
- **Stressed conditions are exactly when correct prices are most informative** for identifying …
  - the location of existing weaknesses on the network
  - what new equipment is needed to upgrade the network
  - the net economic benefits of these upgrades
- **Proxy limits for planning system adequacy** (e.g. reserve margins for generating capacity) **hide the real weaknesses** on a network.
Why a SuperOPF?

Proper allocation and valuation of resources requires *true* co-optimization.
Power systems operations and planning problems are computationally **very** complex.

<table>
<thead>
<tr>
<th>Traditional Approach</th>
<th>SuperOPF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Break into manageable sub-problems.</td>
<td>Combine into single mathematical programming framework.</td>
</tr>
<tr>
<td>DC network approximations</td>
<td>full AC network model</td>
</tr>
<tr>
<td>sequential optimization using proxy constraints</td>
<td>simultaneous <strong>co-optimization</strong> with explicit contingencies</td>
</tr>
<tr>
<td>misleading prices</td>
<td>more accurate prices</td>
</tr>
</tbody>
</table>
Problems Combined

Combines several standard problems found in system operation and planning into a single mathematical programming framework

- standard OPF with full AC non-linear network model & constraints
- $n-1$ contingency security with static (post-contingency voltage and flow limits) and dynamic (generator ramp limits, voltage angle difference limits) constraints
- procurement of adequate supply of active & reactive energy and corresponding geographically distributed reserves
- uncertainty of demand, wind, contingencies
- stochastic cost, including cost of post-contingency states
- more accurate prices for day-ahead contracts for energy, reactive supply, reserves
- consistent mechanism for subsequent redispatch and pricing, given specific realization of uncertain quantities
Two Level Structure

- Stochastic co-optimization framework
- Extensible OPF
Extensible OPF Formulation

- standard AC OPF formulation
  - real and reactive nodal power balance
  - transmission flow limits
  - voltage limits
  - generator capability limits
- with some extras
  - polynomial or piecewise-linear costs on real & reactive generation
  - price sensitive demand (dispatchable/interruptible load)
  - voltage angle difference limits
- plus user supplied extensions
  + additional variables
  + additional linear constraints
  + additional costs
MATPOWER Implements 1\textsuperscript{st} Level

- Stochastic co-optimization framework
- Extensible OPF

MATPOWER
Co-optimization Framework

- Replicate network for multiple scenarios.
- Treat each scenario as separate island in single large network.
- Formulate the OPF problem for this unified system
  - Include standard OPF constraints for each island
  - Include standard OPF costs, weighted by probability of scenario
  - All standard OPF variables for all islands are available to impose additional costs & constraints.

- Define additional variables.
  - e.g. reserves, defined as maximum redispatch from a base case

- Define additional linear constraints (can include all variables).
  - e.g. to impose restrictions on transitions between scenarios

- Define additional costs (can include all variables).
  - e.g. on reserve variables
Example Scenario Structure

Base Case

- Contingency 1
- Contingency 2
- \ldots
- Contingency \( k \)
Several Problem Formulations

- Stochastic co-optimization framework
- Extensible OPF
- Day-ahead scheduling
- Real-time redispacht
- Other formulations
- MATPOWER
Current Implementation

- Stage 1 – day-ahead scheduling problem
  - solve for day-ahead strategy that minimizes expected cost, determines reserve allocations, optimal energy contract, expected prices, contingency-specific dispatch

- Stage 2 – real-time redispatch problem
  - solve optimal dispatch for realized scenario (intact system or contingency) consistent with day-ahead solution, i.e. subject to available reserve contracts
Stage 1: Day-ahead Scheduling

- One base + multiple contingency scenarios
- Standard OPF constraints & probability weighted costs for each scenario
- Add variables for optimal energy contract, up/downward redispatch from contract, up/downward reserves (defined as maximum redispatch)
- Add constraints to define relationships between the new variables.
- Add ramp limits to constrain transitions from base scenario to contingencies.
- Minimize expected cost of energy + expected cost of redispatch + cost of reserves.
## Notation

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$n_c$</td>
<td>number of contingencies</td>
</tr>
<tr>
<td>$n_g$</td>
<td>total number of dispatchable units (gens or loads)</td>
</tr>
<tr>
<td>$k$</td>
<td>index for contingencies (0 for base case)</td>
</tr>
<tr>
<td>$i$</td>
<td>index for dispatchable units (gens or loads)</td>
</tr>
<tr>
<td>$p_{ik}$</td>
<td>real power output for unit $i$ in contingency $k$</td>
</tr>
<tr>
<td>$p_{ci}$</td>
<td>day-ahead contracted real power output for unit $i$</td>
</tr>
<tr>
<td>$p_{ik}^+$, $p_{ik}^-$</td>
<td>upward, downward deviations of $p_{ik}$ from $p_{ci}$</td>
</tr>
<tr>
<td>$r_{Pi}^+$, $r_{Pi}^-$</td>
<td>upward, downward reserves ($\max_k p_{ik}^+$, $\max_k p_{ik}^-$) for unit $i$</td>
</tr>
<tr>
<td>$\pi_k$</td>
<td>probability of contingency $k$</td>
</tr>
<tr>
<td>$C(\cdot)$</td>
<td>cost function</td>
</tr>
<tr>
<td>$G^k$</td>
<td>set of units available in contingency $k$</td>
</tr>
<tr>
<td>$R_{Pi}^{\text{max}+}$, $R_{Pi}^{\text{max}-}$</td>
<td>upward, downward reserve capacity limits for unit $i$</td>
</tr>
<tr>
<td>$\Delta_{Pi}^+$, $\Delta_{Pi}^-$</td>
<td>upward, downward physical ramp limits for unit $i$</td>
</tr>
</tbody>
</table>

replace $p$ with $q$ and $P$ with $Q$ for corresponding values for reactive power
Stage 1 Objective Function

\[ \min_{\Theta, V, P, Q, P_c, P^+, P^-, R^+_P, R^-_P} \left\{ \sum_{k=0}^{n_c} \pi_k \sum_{i \in G^k} C_{Pi}(p_{ik}) + C^+_{Pi}(p^+_{ik}) + C^-_{Pi}(p^-_{ik}) \right. \]

\[ + \sum_{i=1}^{n_g} C^+_{RPi}(r^+_{Pi}) + C^-_{RPi}(r^-_{Pi}) \right\} \]

plus corresponding terms for reactive power
Standard OPF Constraints

... replicated for each contingency
- nodal real & reactive power balance equations
- branch flow limits, voltage limits, generation limits, etc.

\[
\begin{align*}
g_P^k(\theta^k, V^k, P^k, Q^k) &= 0 \\
g_Q^k(\theta^k, V^k, P^k, Q^k) &= 0 \\
h^k(\theta^k, V^k, P^k, Q^k) &\leq 0
\end{align*}
\]  
\[k = 0 \ldots n_c\]
Stage 1 Linking Constraints

\[
\begin{align*}
0 & \leq p_{ik}^+ \\
 p_{ik} - p_{ci} & \leq p_{ik}^+ \\
 p_{ik}^+ & \leq r_{Pi}^+ \leq R_{Pi}^{\text{max}+} \\
0 & \leq p_{ik}^- \\
 p_{ci} - p_{ik} & \leq p_{ik}^- \\
 p_{ik}^- & \leq r_{Pi}^- \leq R_{Pi}^{\text{max}^-} \\
-\Delta_{Pi}^- & \leq p_{ik} - p_{i0} \leq \Delta_{Pi}^+ & \forall k, \forall i \in G_k \\
-\alpha & \leq p_{i0} - p_{ci} \leq \alpha & \forall i, \alpha \in \{0, \infty\}
\end{align*}
\]

plus corresponding constraints for reactive power
Stage 2: Real-time Redispatch

- Same as day-head except:
  - updated scenarios (demand forecasts, available equipment, wind forecasts, credible contingencies, probabilities, etc.)
  - redispatch is relative to the now fixed contract from stage 1
  - reserve quantities from stage 1 appear as fixed limits on redispatch

- Implemented two formulations to simulate the two types of realized scenarios
  1. base or “intact” scenario
     - continue to guard against contingencies
  2. contingency or “outage” scenario
     - becomes new base case, temporarily ignore possibility of further contingencies (did not plan for n-2).
Stage 2 Objective Function

\[
\min_{\Theta, V, P, Q, P^+, P^-} \left\{ \sum_{k=0}^{n_c} \pi_k \sum_{i \in G^k} C_{Pi}(p_{ik}) + C_{Pi}^+(p_{ik}^+) + C_{Pi}^-(p_{ik}^-) \right\}
\]

plus corresponding terms for reactive power
... replicated for each contingency
- nodal real & reactive power balance equations
- branch flow limits, voltage limits, generation limits, etc.

\[
\begin{align*}
    g_P^k (\theta^k, V^k, P^k, Q^k) &= 0 \\
    g_Q^k (\theta^k, V^k, P^k, Q^k) &= 0 \\
    h^k (\theta^k, V^k, P^k, Q^k) &\leq 0 \\
\end{align*}
\]
Stage 2 Linking Constraints

\[
\begin{align*}
0 & \leq p_{ik}^+ \\
\hat{p}_{ci} - p_{ik}^+ & \leq p_{ik}^+ \\
p_{ik}^+ & \leq \bar{r}_P
\end{align*}
\]
\[
\forall k, \forall i \in G_k
\]

\[
\begin{align*}
0 & \leq p_{ik}^- \\
\hat{p}_{ci} - p_{ik}^- & \leq p_{ik}^- \\
p_{ik}^- & \leq \bar{r}_P
\end{align*}
\]
\[
\forall k, \forall i \in G_k
\]

\[-\Delta_{P_i} \leq p_{ik} - p_{i0} \leq \Delta_{P_i} \quad k = 1 \ldots n_c, \forall i \in G_k\]
Historical Background

co-optimization across contingencies

➢ Replicate power flow equations for each post-contingency scenario, impose linking constraints between base case and post-contingency variables to ensure feasibility of post-contingency power flows.

➢ Old concept, rarely implemented literally, preserving prices
  – Alsac & Stott, 1974
  – Burchett & Happ, 1983
  – Damrongkulkamjorn, Gedra, Condren, 2006
    • going back to 1998, not disseminated
    • formulation includes stochastic cost, AC model, interruptible load, ramping costs
    • numerical results based on DC model
    • does not include concept of reserves
  – work at Cornell, since 2001
Evolving Work at Cornell

- Post-contingency power flows as islands linked by ramp limits for security and distributed reserves (Murillo-Sánchez, 2001).
- Stochastic cost, reserves as max upward deviation of a post-contingency dispatch from the base case, redispatch limits under contingencies, experimental market tests (Jie Chen, 2002-2003).
- Two-sided reserves as max deviations from a reference, inc/dec costs on post-contingency redispatch, two stage structure, inclusion of reactive reserves (Murillo-Sánchez, Zimmerman, 2005).
- Energy contract (not base dispatch) as reference for redispatch and reserves (Murillo-Sánchez, Zimmerman, 2006).
- Implementation, testing, case studies.
Our Primary Contributions

- More comprehensive formulation
- Reserves
  - defined as max deviations from a reference value
  - endogenously determined
  - geographically distributed
  - contracted day-ahead
  - separate up & down, real & reactive
- Separation of optimal day-ahead contract from physical dispatch
- Consistent two stage structure
  - day-ahead scheduling
  - real-time redispatch
**Broader Application**

- Began in context of energy and reserve scheduling problem.
- Conceptual framework lends itself to many other applications
- General co-optimized **planning** over multiple scenarios
  - day-ahead energy and reserve scheduling followed by consistent real-time redispatch
  - planning for uncertain energy sources – wind, solar, demand response
  - studying economic & reliability impact of environmental policies
  - solving for sequence of dispatches to find feasible restoration path after a disturbance
  - extension of previous public/private goods studies to full network
  - planning of optimal investment in generation capacity, reactive supply and demand response capability
  - All with more accurate pricing
Case Studies

Focus of recent work …

- Developing simulation infrastructure (3rd level) for case studies
- TESTING! Exercising current implementation with several case studies exploring:
  - importance of modeling loss-of-load during contingencies to properly value assets needed for reliability
  - value of transmission, reliability vs. congestion value
  - impacts of environmental regulations
  - impacts of adding uncertain sources (wind) to an existing system
Case Study 1
Reliability

Determining the Economic Benefits of Avoiding Loss-of-Load during Contingencies
30-bus Network

Area 1
- Urban
- High Load
- High Cost
- VOLL = $10,000/MWh

Area 3
- Rural
- Low Load
- Low Cost
- VOLL = $5,000/MWh

Area 2
- Rural
- Low Load
- Low Cost
- VOLL = $5,000/MWh
# Contingencies Considered

*(Transmission Lines, Generating Units and Load Realizations)*

<table>
<thead>
<tr>
<th>Number</th>
<th>Description</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>base case</td>
<td>95%</td>
</tr>
<tr>
<td>1</td>
<td>line 1 : 1-2 (between gens 1 and 2, within area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>2</td>
<td>line 2 : 1-3 (from gen 1, within area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>3</td>
<td>line 3 : 2-4 (from gen 2, within area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>4</td>
<td>line 5 : 2-5 (from gen 2, within area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>5</td>
<td>line 6 : 2-6 (from gen 2, within area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>6</td>
<td>line 36 : 27-28 (main tie from area 3 to area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>7</td>
<td>line 15 : 4-12 (main tie from area 2 to area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>8</td>
<td>line 12 : 6-10 (other tie from area 3 to area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>9</td>
<td>line 14 : 9-10 (other tie from area 3 to area 1)</td>
<td>0.2%</td>
</tr>
<tr>
<td>10</td>
<td>gen 1</td>
<td>0.2%</td>
</tr>
<tr>
<td>11</td>
<td>gen 2</td>
<td>0.2%</td>
</tr>
<tr>
<td>12</td>
<td>gen 3</td>
<td>0.2%</td>
</tr>
<tr>
<td>13</td>
<td>gen 4</td>
<td>0.2%</td>
</tr>
<tr>
<td>14</td>
<td>gen 5</td>
<td>0.2%</td>
</tr>
<tr>
<td>15</td>
<td>gen 6</td>
<td>0.2%</td>
</tr>
<tr>
<td>16</td>
<td>10% increase in load</td>
<td>1.0%</td>
</tr>
<tr>
<td>17</td>
<td>10% decrease in load</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

---

3% 2%
Underlying Rationale

- Area 1 represents an urban load pocket with high load, high cost generation, and high Value of Lost Load (VOLL).
- Areas 2 and 3 represent rural areas with low load, low cost generation, and low VOLL.
- Transmission capacity into Area 1 from Areas 2 and 3 is relatively limited.
- An economic dispatch would use generation in Areas 2 and 3 as much as possible and use generating capacity in Area 1 for reserves to maintain operating reliability (e.g. guard against failure of the tie lines into Area 1).
- In this case study
  - operating costs remain constant
  - offers equal the true marginal costs
  - all loads in Area 1 are increased in increments until things start to go wrong (i.e. load shedding occurs at one or more nodes in one or more of the contingencies).
**Expected Nodal Prices for Generators**

*Price Differences are Caused by Congestion*

Higher Load in the Load Pocket (Region 1) ->
Expected Nodal Prices for Loads

Large price differences in Area 1 are caused by load shedding – very localized effect

$10,000/MWh

Higher Load in the Load Pocket (Region 1) -> $10/MWh
The Expected Cost of Lost Load
Weighted by the Probability of Each Contingency Occurring

Higher Load in the Load Pocket (Area 1) ->
Problems show up first in **contingencies** as system load increases. The capacity of **Line 10 in Area 1** is the binding constraint.

<table>
<thead>
<tr>
<th>Contingency</th>
<th>Scale Factor for Load</th>
<th>Load Shedding Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.6</td>
<td>0/ MWh</td>
</tr>
<tr>
<td></td>
<td>0.7</td>
<td>0/ MWh</td>
</tr>
<tr>
<td></td>
<td>0.8</td>
<td>0/ MWh</td>
</tr>
<tr>
<td></td>
<td>0.9</td>
<td>0/ MWh</td>
</tr>
<tr>
<td></td>
<td>1.0</td>
<td>0/ MWh</td>
</tr>
<tr>
<td></td>
<td>1.1</td>
<td>0/ MWh</td>
</tr>
<tr>
<td></td>
<td>1.2</td>
<td>0/ MWh</td>
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<tr>
<td></td>
<td>1.3</td>
<td>0/ MWh</td>
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<tr>
<td></td>
<td>1.4</td>
<td>0/ MWh</td>
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<tr>
<td></td>
<td>1.5</td>
<td>0/ MWh</td>
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<td>1.6</td>
<td>0/ MWh</td>
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<td>1.8</td>
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<td>0/ MWh</td>
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<td>0/ MWh</td>
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<td>0/ MWh</td>
</tr>
<tr>
<td></td>
<td>4.5</td>
<td>0/ MWh</td>
</tr>
</tbody>
</table>

- **$31,600/MWh**
- **$0/MWh**
The Question for Planners
Will it Pay to Increase the Capacity of Line 10?

- Specify the hourly loads for a year.
- Specify a peak load level.
- Determine nodal prices, revenues, costs
- Compute annual totals
## Expected Annual Values

*currency in millions of $

<table>
<thead>
<tr>
<th>load scale factor</th>
<th>1.1</th>
<th>1.15</th>
<th>1.2</th>
<th>1.25</th>
<th>1.3</th>
<th>1.35</th>
<th>1.4</th>
</tr>
</thead>
<tbody>
<tr>
<td>pmt from loads</td>
<td>$24.8</td>
<td>$27.0</td>
<td>$29.8</td>
<td>$32.8</td>
<td>$36.0</td>
<td>$71.4</td>
<td>$108.3</td>
</tr>
<tr>
<td>w/no shedding</td>
<td>$24.8</td>
<td>$26.9</td>
<td>$29.2</td>
<td>$31.7</td>
<td>$34.4</td>
<td>$36.1</td>
<td>$38.8</td>
</tr>
<tr>
<td>with shedding</td>
<td>$0.0</td>
<td>$0.1</td>
<td>$0.6</td>
<td>$1.1</td>
<td>$1.6</td>
<td>$35.3</td>
<td>$69.4</td>
</tr>
<tr>
<td>pmt to gens</td>
<td>$23.8</td>
<td>$25.4</td>
<td>$26.8</td>
<td>$28.4</td>
<td>$29.8</td>
<td>$31.4</td>
<td>$33.2</td>
</tr>
<tr>
<td>gen cost</td>
<td>$8.8</td>
<td>$9.3</td>
<td>$9.8</td>
<td>$10.4</td>
<td>$11.1</td>
<td>$11.7</td>
<td>$12.4</td>
</tr>
<tr>
<td>cost of LNS</td>
<td>$0.0</td>
<td>$0.0</td>
<td>$0.0</td>
<td>$0.0</td>
<td>$0.1</td>
<td>$1.3</td>
<td>$3.5</td>
</tr>
<tr>
<td>total cost of gen &amp; LNS</td>
<td>$8.8</td>
<td>$9.3</td>
<td>$9.8</td>
<td>$10.5</td>
<td>$11.2</td>
<td>$13.0</td>
<td>$15.9</td>
</tr>
<tr>
<td>hrs of load shedding</td>
<td>0.0</td>
<td>0.4</td>
<td>1.8</td>
<td>3.0</td>
<td>4.4</td>
<td>91.3</td>
<td>179.2</td>
</tr>
<tr>
<td>MWh of load shedding</td>
<td>0.0</td>
<td>0.3</td>
<td>1.4</td>
<td>4.4</td>
<td>9.8</td>
<td>129.9</td>
<td>349.5</td>
</tr>
</tbody>
</table>
Conclusions: Case Study 1 on Reliability

- The engineering/economic framework of the SuperOPF can be used to evaluate both planning (System Adequacy) and real-time dispatch (Operating Reliability).
- Weaknesses in System Adequacy (shedding load) tend to occur first in contingencies when the system load is high, and for most hours of the year, reliability standards are not violated.
- The location of weaknesses on the network at the system peak load can be identified, and the net economic benefit of upgrading the network over a year’s operations can be determined.
- A large part of the economic benefit of adding new capacity to a network may be to avoid load shedding when credible contingencies occur (e.g. N-1 contingencies).
- The economic effects of shedding load (i.e. high nodal prices) are often spatially limited to specific loads, and as a result, using controllable load or storage to reduce that load may be the most economically efficient way to maintain reliability standards.
Case Study 2
Renewables

Replacing Coal Capacity with Wind Capacity on the 30-bus Test Network
Area 1
- Urban
- High Load
- High Cost
- VOLL = $10,000/MWh

Area 2
- Rural
- Low Load
- Low Cost
- VOLL = $5,000/MWh

Area 3
- Rural
- Low Load
- Low Cost
- VOLL = $5,000/MWh

Wind Farm

Improved Tie Line
Underlying Rationale

- Area 1 represents an urban load pocket with high load, high cost generation, and high VOLL.
- Areas 2 and 3 represent rural areas with low load, low cost generation, and low VOLL.
- Transmission capacity into Area 1 from Areas 2 and 3 is relatively limited.
- Replace 35MW of coal capacity by 105MW of wind capacity at Generator 6 (Area 2) in increments.
  - Case 1: Initial network capacity
  - Case 2: Upgrade tie line from Area 2 to Area 1
- For a given forecast of wind speed, the range of actual realizations of wind generation is large and additional reserve generating capacity is needed to deal with this uncertainty.
### Wind Forecasts and Realizations

<table>
<thead>
<tr>
<th>Forecasted Wind Speed</th>
<th>Probability of Forecast</th>
<th>Output (% of MW Installed)</th>
<th>Output Probability (Conditional on Forecast)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>LOW (0-5 m/s)</strong></td>
<td>11%</td>
<td>0%</td>
<td>66%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7%</td>
<td>26%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>33%</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>73%</td>
<td>3%</td>
</tr>
<tr>
<td><strong>MEDIUM (5-13 m/s)</strong></td>
<td>46%</td>
<td>6%</td>
<td>24%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>38%</td>
<td>20%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>62%</td>
<td>18%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>93%</td>
<td>38%</td>
</tr>
<tr>
<td><strong>HIGH (13+ m/s)</strong></td>
<td>43%</td>
<td>0%</td>
<td>14%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>66%</td>
<td>4%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>94%</td>
<td>3%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>100%</td>
<td>79%</td>
</tr>
</tbody>
</table>
Contingencies Considered
(Transmission Lines, Generating Units and Wind Realizations)

0 = wind 1  (root case)
1 = wind 2
2 = wind 3
3 = wind 4
4 = line 1 : 1-2  (between gens 1 and 2, within area 1)
5 = line 2 : 1-3  (from gen 1, within area 1)
6 = line 3 : 2-4  (from gen 2, within area 1)
7 = line 5 : 2-5  (from gen 2, within area 1)
8 = line 6 : 2-6  (from gen 2, within area 1)
9 = line 36 : 27-28  (main tie, areas 1-3)
10 = line 15 : 4-12  (main tie, areas 1-2)
11 = line 12 : 6-10  (other tie, areas 1-3)
12 = line 14 : 9-10  (other tie, areas 1-3)
13 = gen 1
14 = gen 2
15 = gen 3
16 = gen 4
17 = gen 5
18 = gen 6

All Equipment Failures are Specified at the Lowest Realization of Wind

97%
3%
Expected Total Non-Wind Reserve Capacity
(Increasing Wind Capacity at Peak System Load)

Case 1: Base Case
More Wind Capacity →
Optimum Levels of Up and Down Generating Reserves are Determined Endogenously and Increase when Additional Wind Capacity is Installed

Case 2: Tie Line L15 upgraded
(Tie line between Area 1 and Area 2)
More Wind Capacity →
Expected Production Costs ($/MW of Load)  
(Increasing Wind Capacity at Peak System Load)

Case 1: Base Case
More Wind Capacity $\rightarrow$
Savings in Fuels Costs are Larger than the Increase in Costs for Reserves when Additional Wind Capacity is Installed

Case 2: Tie Line L15 upgraded
(Tie line between Area 1 and Area 2)
More Wind Capacity $\rightarrow$
The Next Question

For a given level of peak system load, what are the financial implications for the annual earnings of different participants in the market of higher levels of wind capacity?
Expected Annual Values (0 MW of wind) (High ← Ranked System Load → Low)

Congestion (ISO)
Gen. Net Revenue
True Operating Costs

Tie Line Upgraded
No Upgrade

Expected Annual Value Case 1 (0 MW Wind penetration)

Expected Annual Value Case 2 (0 MW Wind penetration)
Expected Annual Values (105 MW of wind)
(High ← Ranked System Load → Low)

- Tie Line Upgraded
- No Upgrade

Congestion (ISO)
Wind Net Revenue
Gen. Net Revenue
True Operating Costs

Expected Annual Value Case 1 (106 MW Wind penetration)

Expected Annual Value Case 2 (106 MW Wind penetration)
### Maximum Capacities Dispatched at the PEAK System Load

<table>
<thead>
<tr>
<th></th>
<th>Case1 ----&gt; Initial System</th>
<th>Case2 ----&gt; Upgrade Tie Line</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0%*</td>
<td>25%*</td>
</tr>
<tr>
<td>Gen1</td>
<td>36.37%</td>
<td>43.83%</td>
</tr>
<tr>
<td>Gen2</td>
<td>50.39%</td>
<td>77.89%</td>
</tr>
<tr>
<td>Gen3</td>
<td>99.75%</td>
<td>100.00%</td>
</tr>
<tr>
<td>Gen4</td>
<td>84.36%</td>
<td>89.37%</td>
</tr>
<tr>
<td>Gen5</td>
<td>100.00%</td>
<td>100.00%</td>
</tr>
<tr>
<td>Gen6</td>
<td>96.50%</td>
<td>100.00%</td>
</tr>
<tr>
<td>Wind</td>
<td>0.00%</td>
<td>73.42%</td>
</tr>
</tbody>
</table>

* Percentage of the Total Installed Capacity

For most Non-Wind Generators, MORE CAPACITY (energy + up reserves) is needed to meet the SAME PEAK System Load when more wind capacity is installed (RED is an INCREASE or the same as 0% wind)
# Expected Annual Capacity Factors

<table>
<thead>
<tr>
<th></th>
<th>Case1 ----&gt; Initial System</th>
<th>Case2 ----&gt; Upgrade Tie Line</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0%*</td>
<td>25%*</td>
</tr>
<tr>
<td>Gen1</td>
<td>0.01%</td>
<td>0.02%</td>
</tr>
<tr>
<td>Gen2</td>
<td>0.04%</td>
<td>0.27%</td>
</tr>
<tr>
<td>Gen3</td>
<td>59.62%</td>
<td>36.04%</td>
</tr>
<tr>
<td>Gen4</td>
<td>57.00%</td>
<td>44.62%</td>
</tr>
<tr>
<td>Gen5</td>
<td>39.65%</td>
<td>24.20%</td>
</tr>
<tr>
<td>Gen6</td>
<td>63.94%</td>
<td>34.46%</td>
</tr>
<tr>
<td>Wind</td>
<td>-</td>
<td>56.18%</td>
</tr>
</tbody>
</table>

* Percentage of the Total Installed Capacity

For Non-Wind Generators in Areas 2 and 3, the capacity factors are LOWER when MORE wind capacity is installed (RED shows a DECREASE). The capacity factors for Non-Wind Generators in Area 1 are always very low.
# Expected Annual Net Benefits
*(Changes from the Initial Conditions)*

<table>
<thead>
<tr>
<th>Level</th>
<th>CASE 1</th>
<th>CASE 1</th>
<th>CASE 2</th>
<th>CASE 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%*</td>
<td></td>
<td>25%*</td>
<td>0%*</td>
<td>25%*</td>
</tr>
<tr>
<td>Change from Case 1 with 0%* ➔</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Operating Costs</td>
<td>$8,224,612</td>
<td>-$4,157,884</td>
<td>-$31,095</td>
<td>-$4,557,138</td>
</tr>
<tr>
<td>Gen Net Rev (14)</td>
<td>$14,172,181</td>
<td>-$9,337,862</td>
<td>$256,922</td>
<td>-$10,513,825</td>
</tr>
<tr>
<td>Wind Net Rev (15)</td>
<td>$0</td>
<td>$706,233</td>
<td>$0</td>
<td>$2,559,206</td>
</tr>
<tr>
<td>Congestion -- ISO (16)</td>
<td>$711,575</td>
<td>$2,088,313</td>
<td>-$652,893</td>
<td>-$1,092,187</td>
</tr>
<tr>
<td>Consumer Surplus (17)</td>
<td>DD – Load Paid**</td>
<td>$10,701,201</td>
<td>$427,066</td>
<td>$13,603,945</td>
</tr>
<tr>
<td>Total Surplus</td>
<td>(14)+(15)+(16)+(17)</td>
<td>$4,157,886</td>
<td>$31,095</td>
<td>$4,557,139</td>
</tr>
</tbody>
</table>

** DD = Sum (Loads Served x VOLL)

* Percentage of the Total Installed Capacity

RED is a DECREASE from Initial System with 0% Wind
Conclusions: Case Study 2 on Renewables

- The analysis of the peak system load for different levels of wind penetration show that total production costs decrease as wind capacity increases, particularly if the tie line is upgraded.
- The annual net benefit for the system (total annual surplus) increases with more wind capacity and with the tie line upgrade (the change in this value should be greater than the annualized cost of an investment for it to be economically viable).
-Adding more wind capacity displaces a high proportion of the conventional generation when system loads are low and also reduces average market (wholesale) prices substantially.
- The net earnings of conventional generators fall substantially with more wind capacity, particularly if the tie line is upgraded, and it is likely that additional sources of revenue would be needed to keep them financially viable (e.g. from Forward Capacity Markets).
- Upgrading the tie line eliminates congestion payments to the System Operator, and additional sources of revenue would be needed to pay for transmission.
- The annual benefits for customers and wind generators increase from both more wind capacity and the tie line upgrade but customers will have other bills to pay for adequate reserves, transmission etc.
Future Directions

- Level 1 – Improve solvers for MATPOWER’s extensible OPF
- Level 2 - Stochastic co-optimization framework
  - add unit-commitment, horizon planning over multiple time periods
  - generalize structure to multiple “base” scenarios
  - explore decomposition and price coordination schemes for parallel computation
  - define formulation for planning of optimal investment
  - implement DC version for use in planning
- Continue work to support case studies (level 3)
Questions?