
A SuperOPF Framework

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

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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

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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.

What is the SuperOPF?

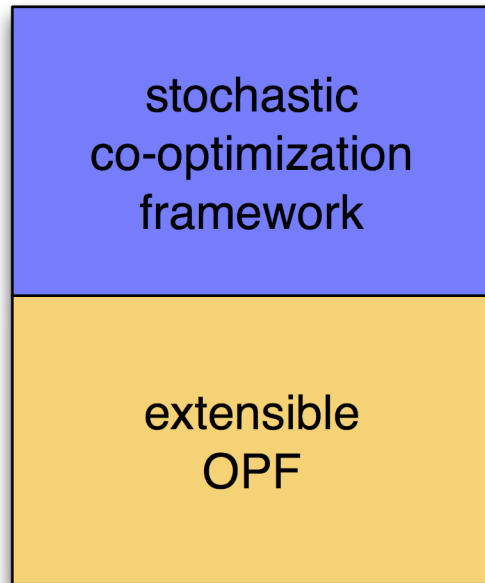
Power systems operations and planning problems are computationally **very** complex.

Traditional Approach	SuperOPF
Break into manageable sub-problems.	Combine into single mathematical programming framework.
DC network approximations	full AC network model
sequential optimization using proxy constraints	simultaneous co-optimization with explicit contingencies
misleading prices	more accurate prices

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

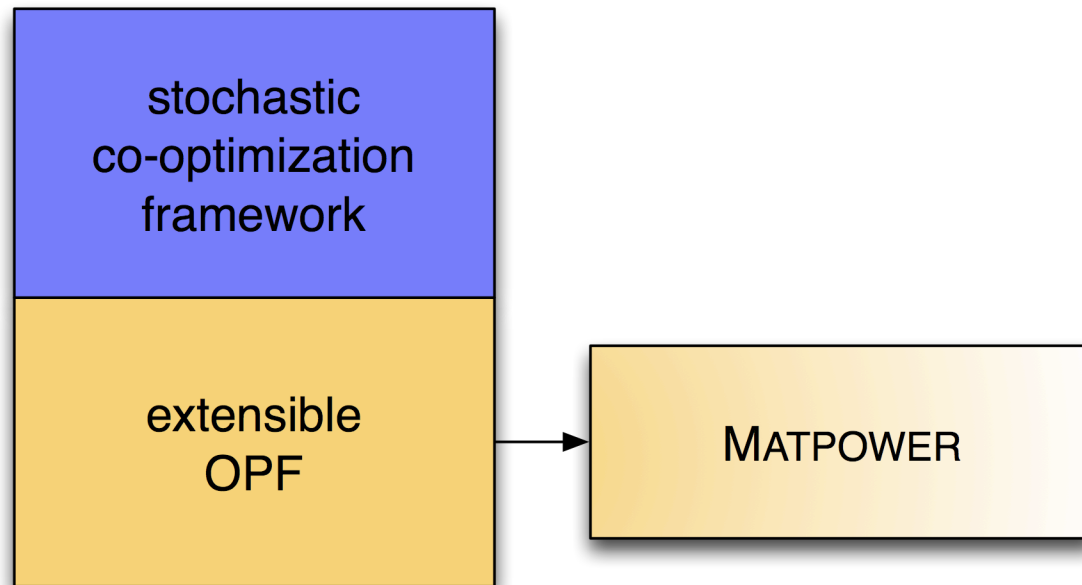
Two Level Structure



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

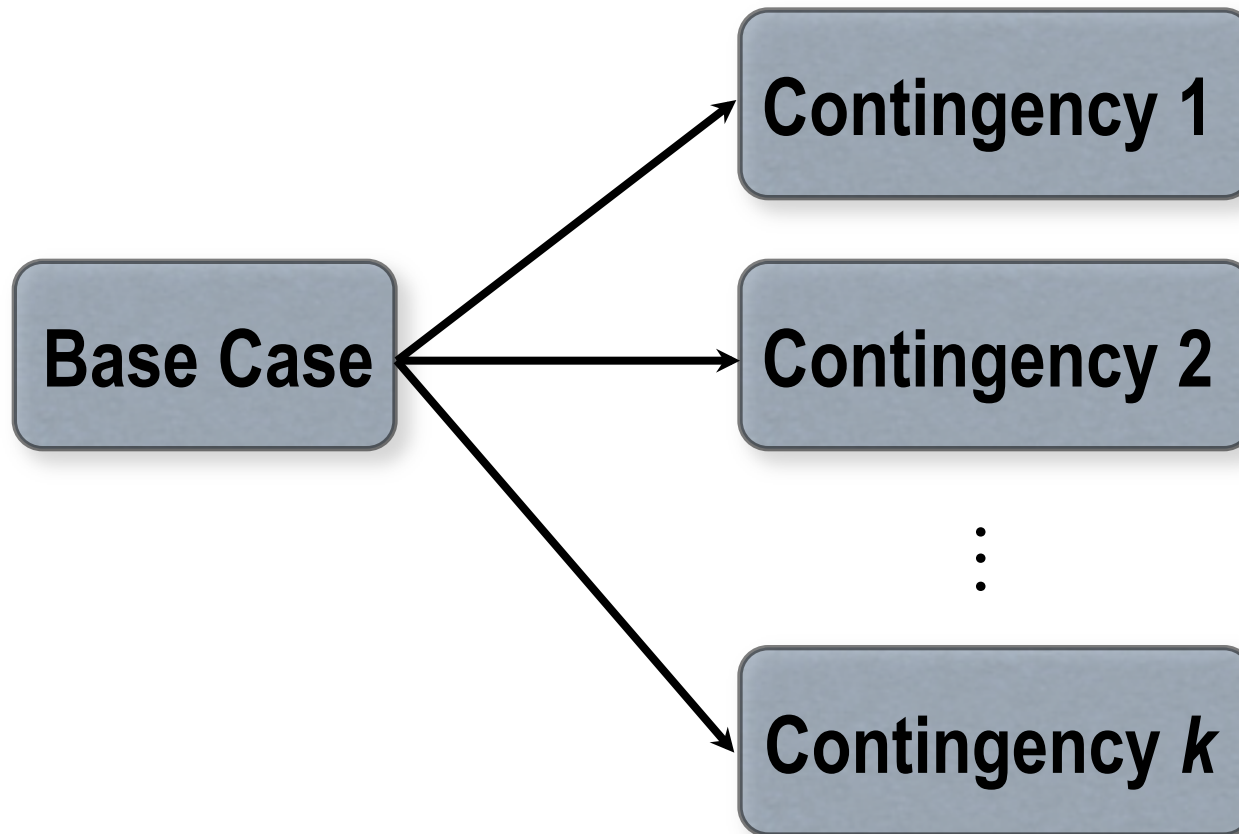
MATPOWER Implements 1st Level



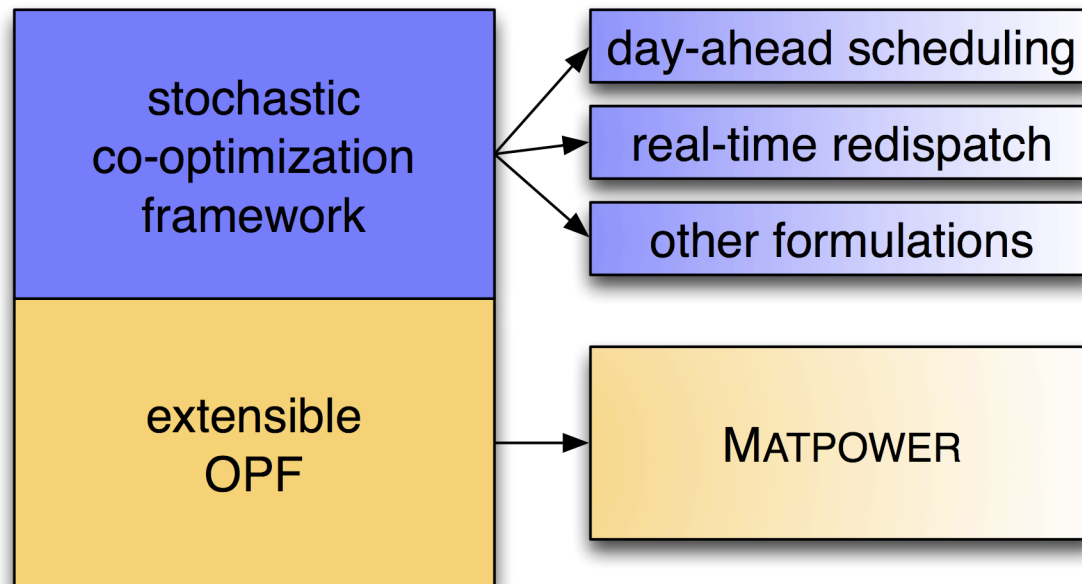
Co-optimization Framework

- 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



Several Problem Formulations



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

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

replace p with q and P with Q for corresponding values for reactive power

Stage 1 Objective Function

$$\min_{\substack{\Theta, V, P, Q, \\ P_c, P^+, P^-, \\ R_P^+, R_P^-}} \left\{ \sum_{k=0}^{n_c} \pi_k \sum_{i \in G^k} C_{Pi}(p_{ik}) + C_{Pi}^+(p_{ik}^+) + C_{Pi}^-(p_{ik}^-) \right. \\ \left. + \sum_{i=1}^{n_g} C_{Ri}^+(r_{Pi}^+) + C_{Ri}^-(r_{Pi}^-) \right\}$$

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.

$$\left. \begin{aligned} g_P^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ g_Q^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ h^k(\theta^k, V^k, P^k, Q^k) &\leq 0 \end{aligned} \right\} k = 0 \dots n_c$$

Stage 1 Linking Constraints

$$\left. \begin{aligned} 0 &\leq p_{ik}^+ \\ p_{ik} - p_{ci} &\leq p_{ik}^+ \\ p_{ik}^+ &\leq r_{Pi}^+ \leq R_{Pi}^{\max+} \\ \\ 0 &\leq p_{ik}^- \\ p_{ci} - p_{ik} &\leq p_{ik}^- \\ p_{ik}^- &\leq r_{Pi}^- \leq R_{Pi}^{\max-} \end{aligned} \right\}$$

plus corresponding
constraints for
reactive power

$$\forall k, \forall i \in G_k$$

$$-\Delta_{Pi}^- \leq p_{ik} - p_{i0} \leq \Delta_{Pi}^+$$

$$k = 1 \dots n_c, \forall i \in G_k$$

$$-\alpha \leq p_{i0} - p_{ci} \leq \alpha$$

$$\forall i, \alpha \in \{0, \infty\}$$

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

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

plus corresponding terms for reactive power

Standard OPF Constraints

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

$$\left. \begin{aligned} g_P^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ g_Q^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ h^k(\theta^k, V^k, P^k, Q^k) &\leq 0 \end{aligned} \right\} \quad k = 0 \dots n_c$$

Stage 2 Linking Constraints

$$\left. \begin{aligned} 0 &\leq p_{ik}^+ \\ p_{ik} - \hat{p}_{ci} &\leq p_{ik}^+ \\ p_{ik}^+ &\leq \hat{r}_{Pi}^+ \end{aligned} \right\}$$

$$\left. \begin{aligned} 0 &\leq p_{ik}^- \\ \hat{p}_{ci} - p_{ik} &\leq p_{ik}^- \\ p_{ik}^- &\leq \hat{r}_{Pi}^- \end{aligned} \right\}$$

plus corresponding
constraints for
reactive power

$$\forall k, \forall i \in G_k$$

$$-\Delta_{Pi}^- \leq p_{ik} - p_{i0} \leq \Delta_{Pi}^+$$

$$k = 1 \dots n_c, \forall i \in G_k$$

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**

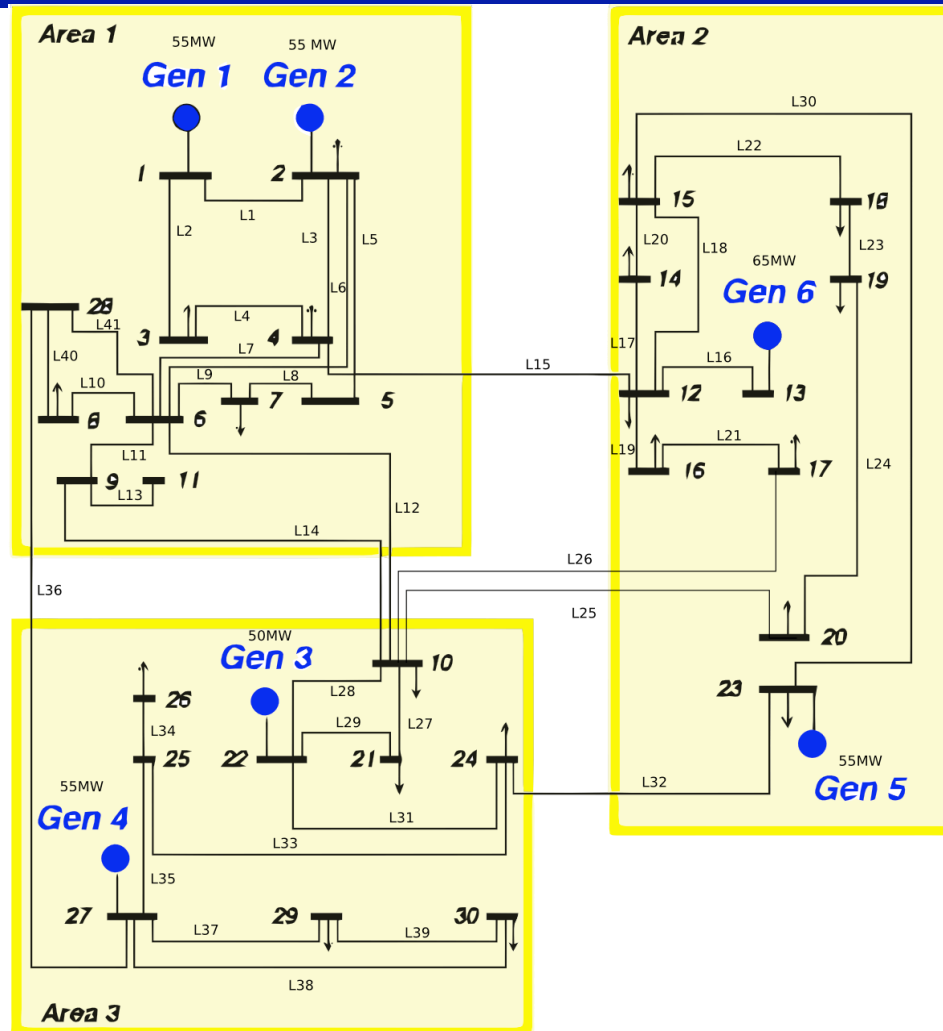
30-bus Network

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)

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

3%

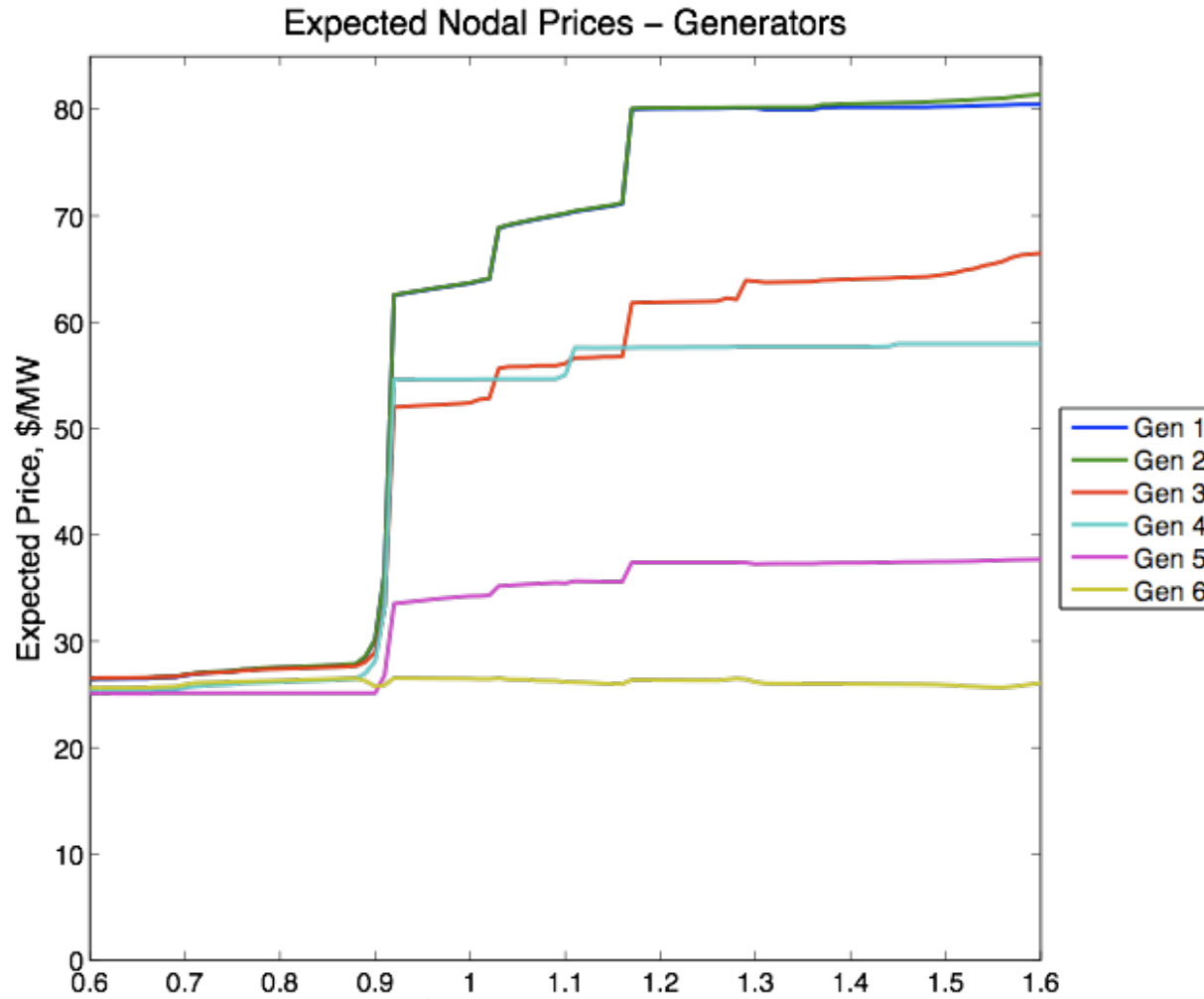
2%

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

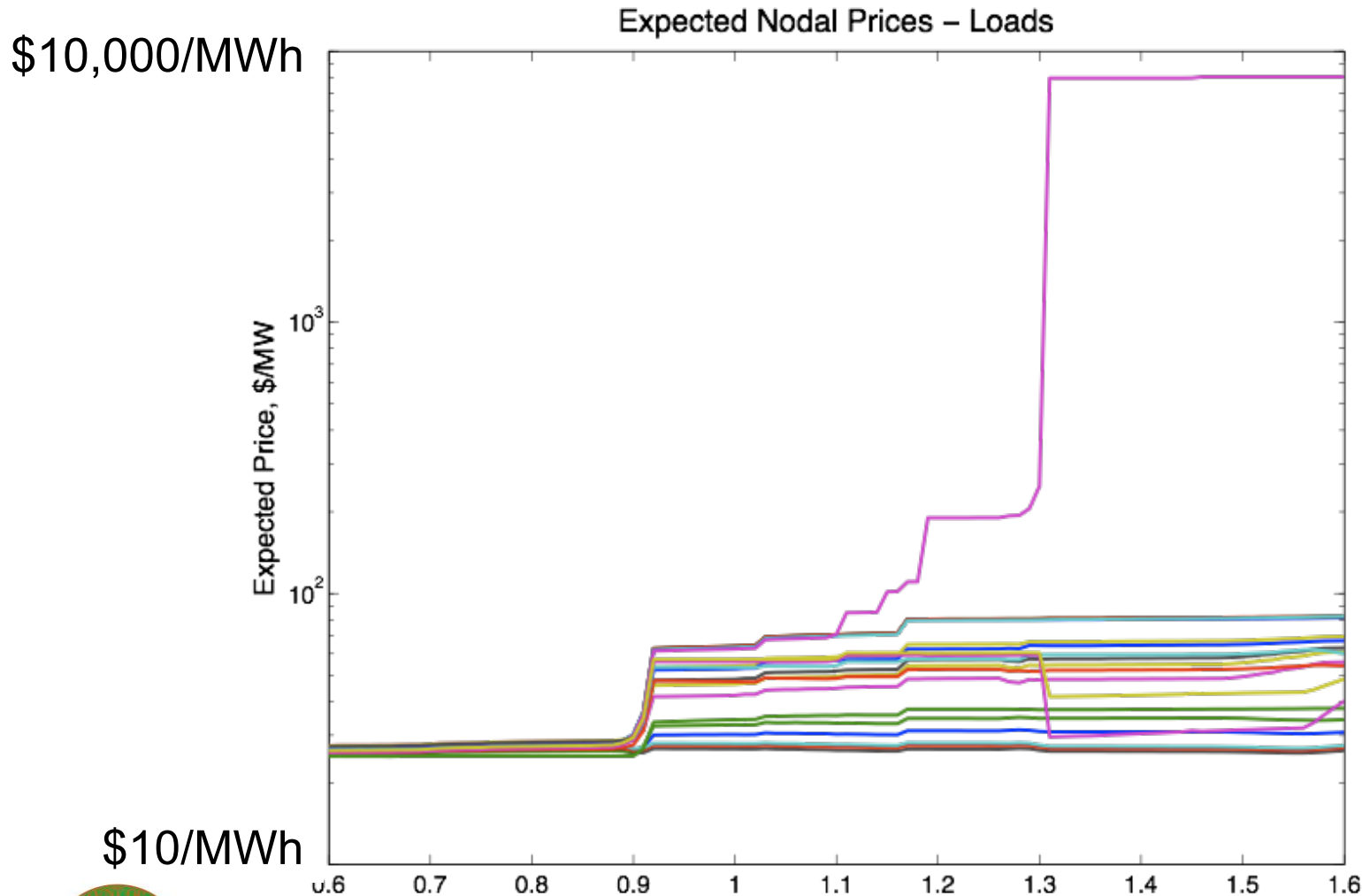
Price Differences are Caused by Congestion



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

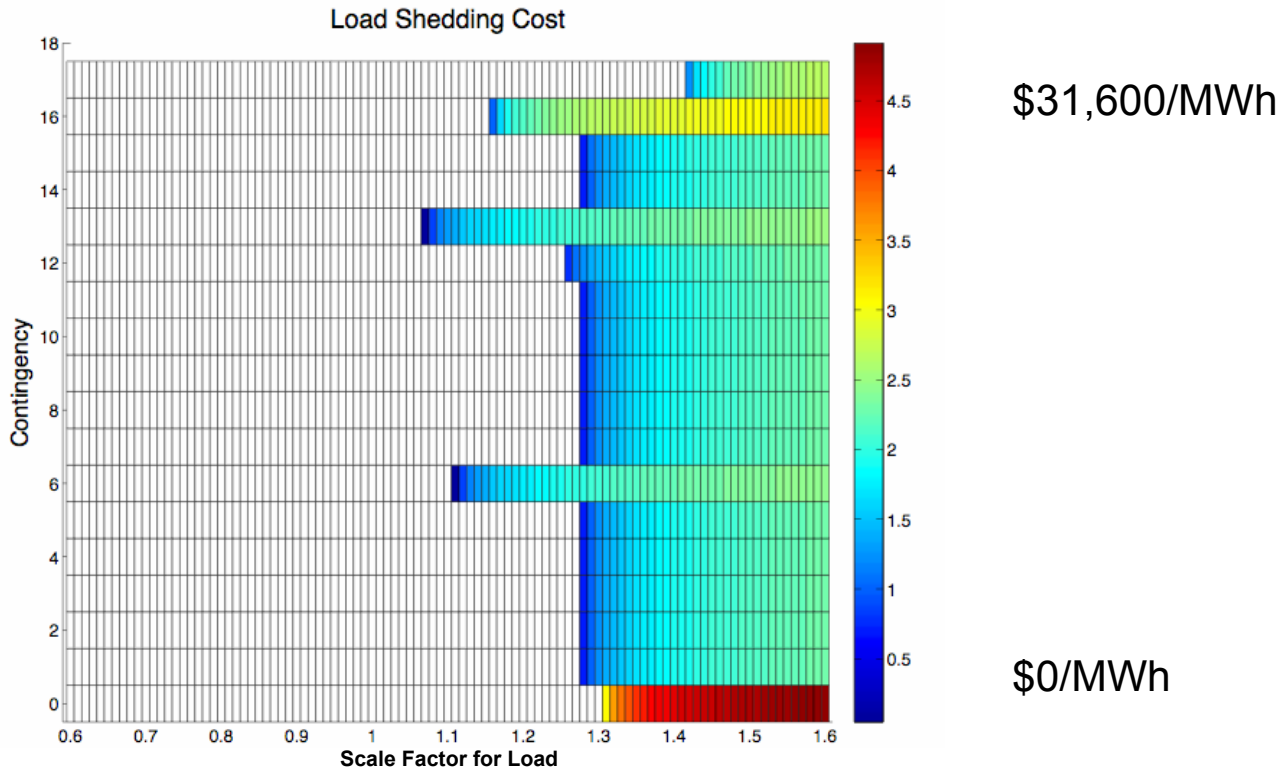


Higher Load in the Load Pocket (Region 1) ->

The Expected Cost of Lost Load

Weighted by the Probability of Each Contingency Occurring

Contingency



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.

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 \$

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

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**

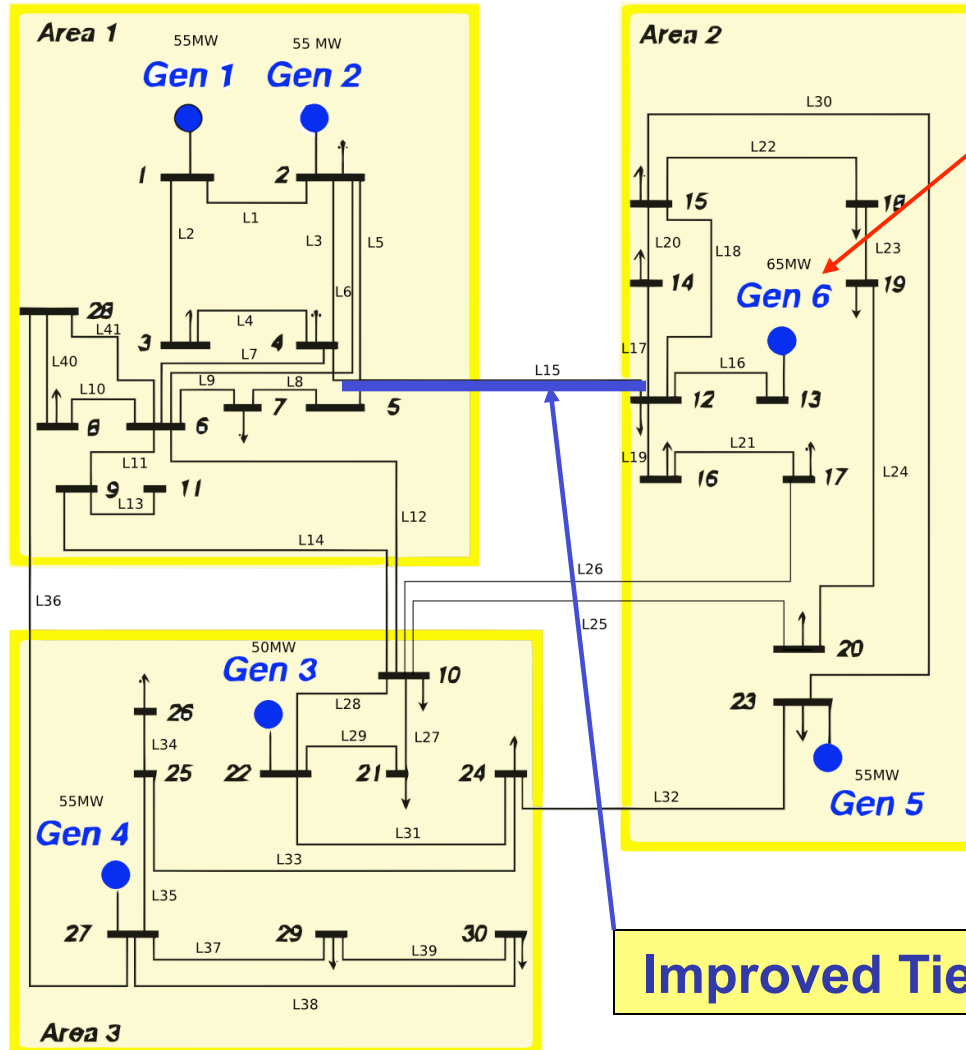
30-bus Network

Area 1

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

Area 3

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



Wind Farm

Area 2

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

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

Forecasted Wind Speed	Probability of Forecast	Output (% of MW Installed)	Output Probability (Conditional on Forecast)
LOW (0-5 m/s)	11%	0%	66%
		7%	26%
		33%	5%
		73%	3%
MEDIUM (5-13 m/s)	46%	6%	24%
		38%	20%
		62%	18%
		93%	38%
HIGH (13+ m/s)	43%	0%	14%
		66%	4%
		94%	3%
		100%	79%

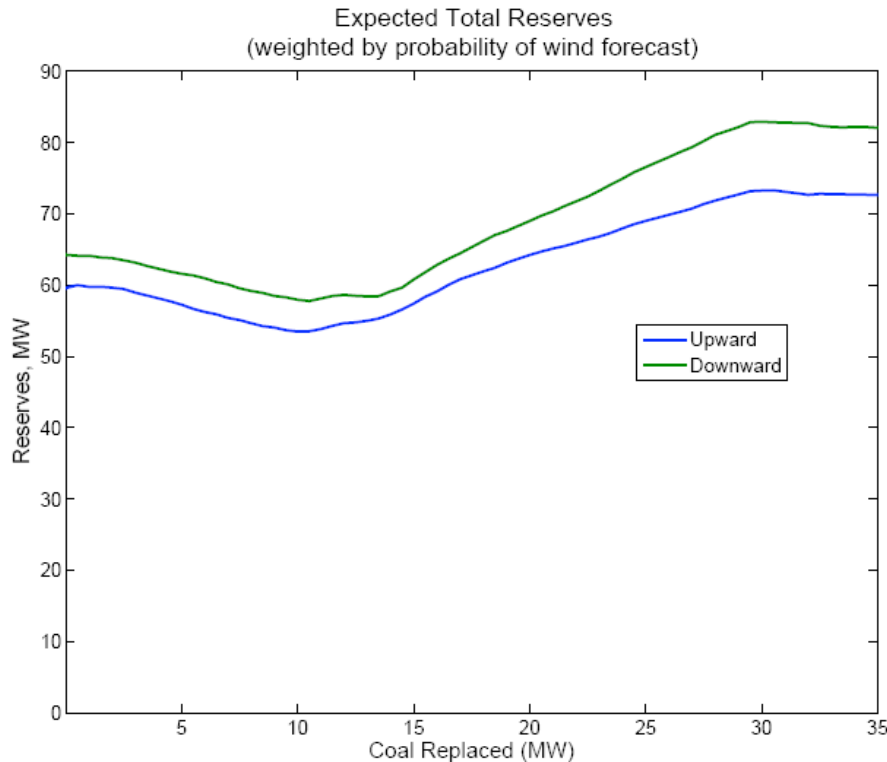
Contingencies Considered

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

0	=	wind 1	(root case)	}	97%
1	=	wind 2			
2	=	wind 3			
3	=	wind 4			
4	=	line 1	: 1-2 (between gens 1 and 2, within area 1)	}	3%
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

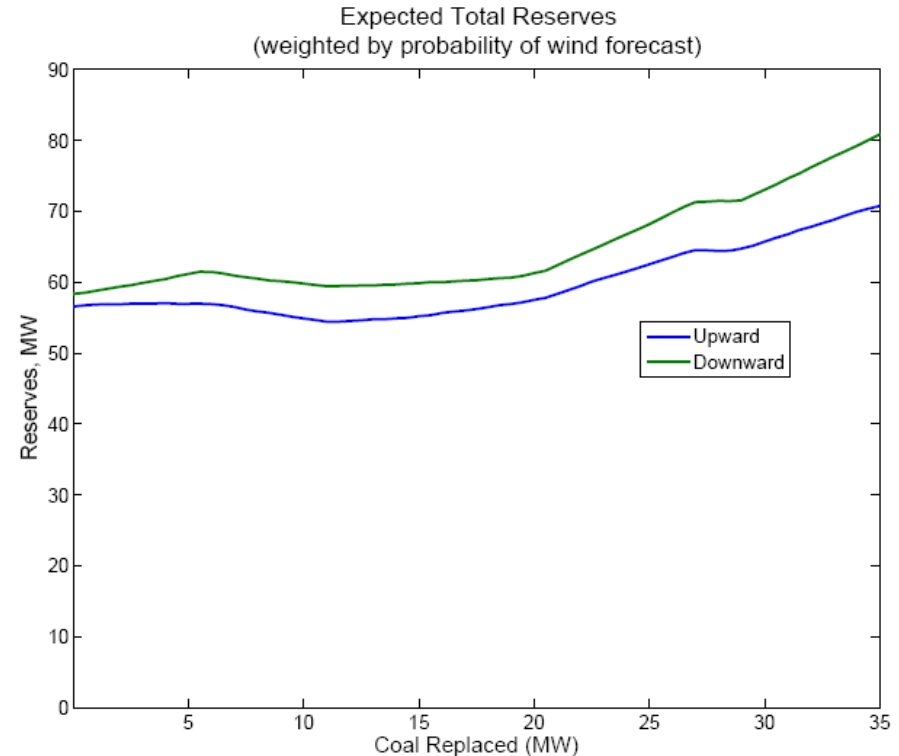
Expected Total Non-Wind Reserve Capacity (Increasing Wind Capacity at Peak System Load)



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

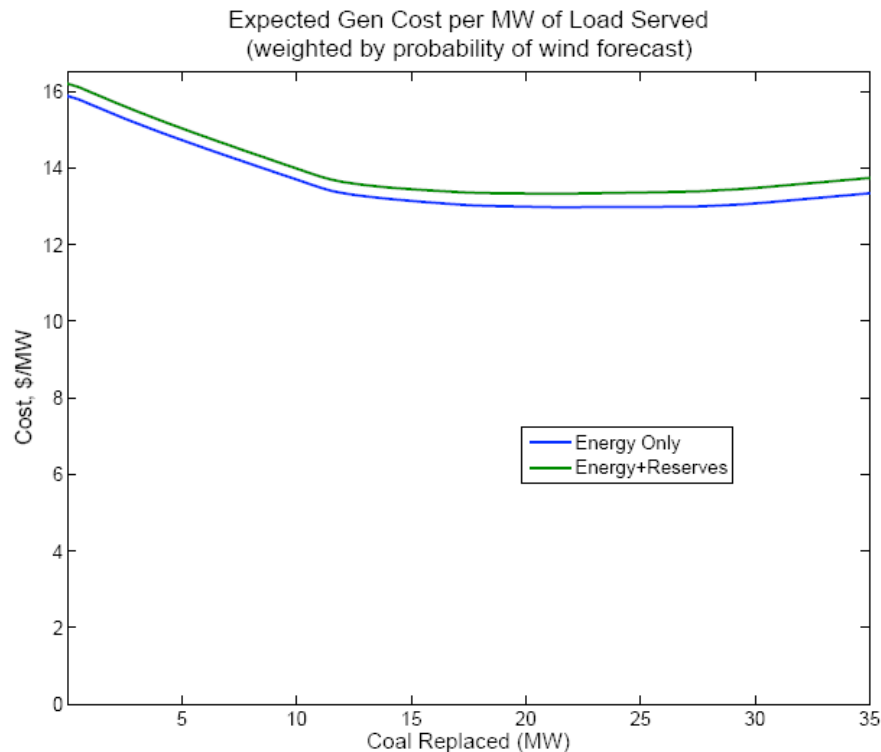


Case 2: Tie Line L15 upgraded
(Tie line between Area 1 and Area 2)

More Wind Capacity →

Expected Production Costs (\$/MW of Load)

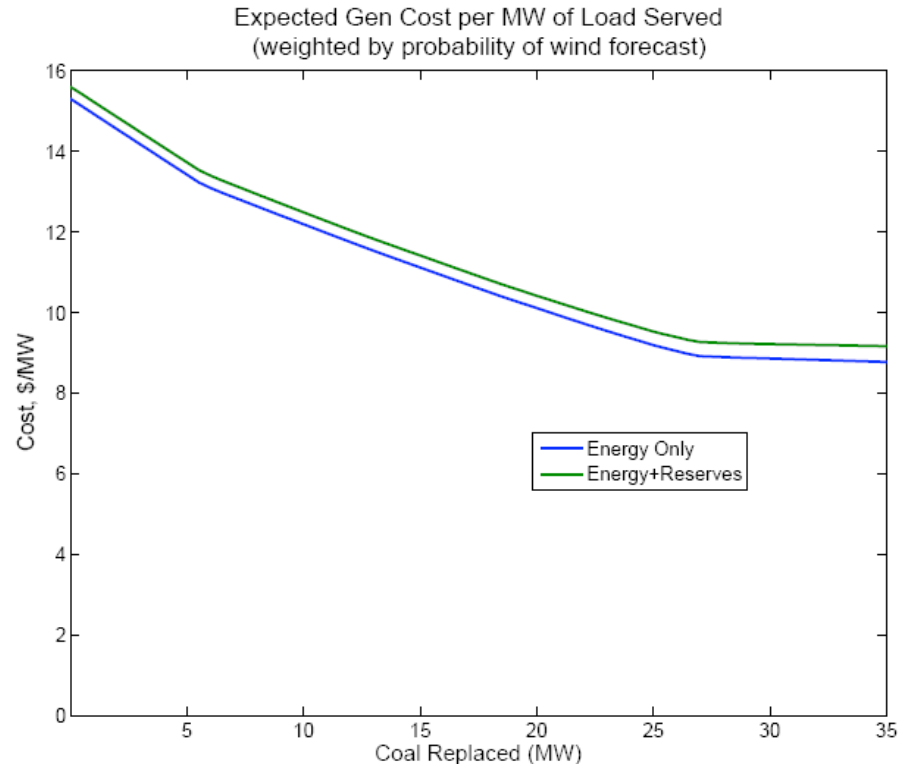
(Increasing Wind Capacity at Peak System Load)



Case 1: Base Case

More Wind Capacity →

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 →

The Next Question

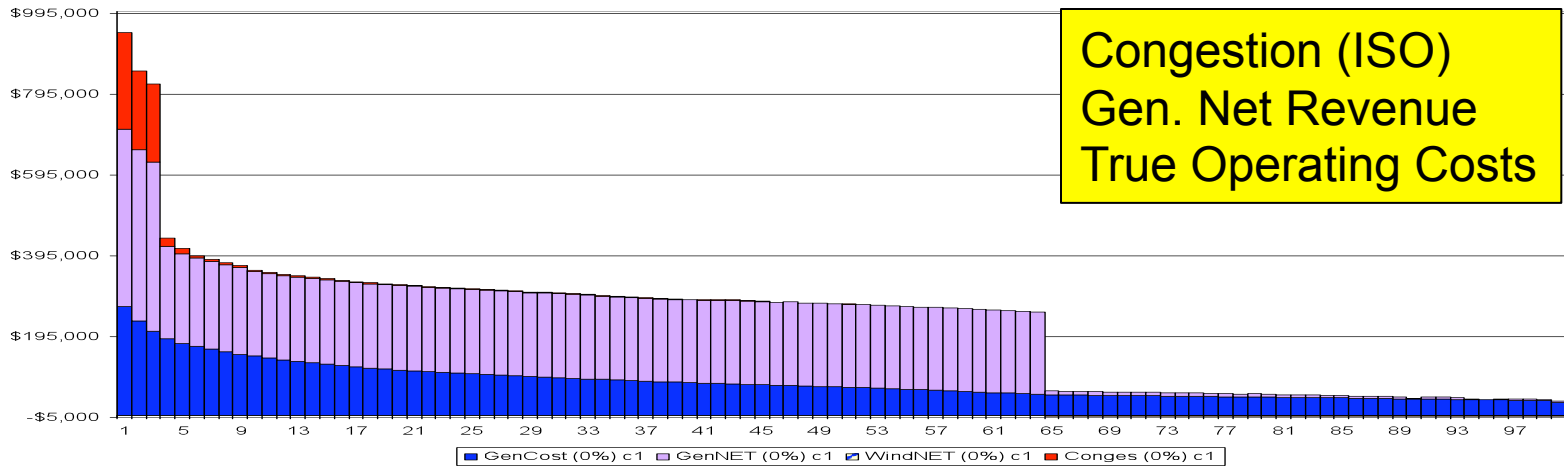
For a given level of **peak system load**,
what are the financial implications for
the **annual earnings** of different
participants in the market of higher
levels of **wind capacity**?

Expected Annual Values (*0 MW of wind*)

(High ← Ranked System Load → Low)

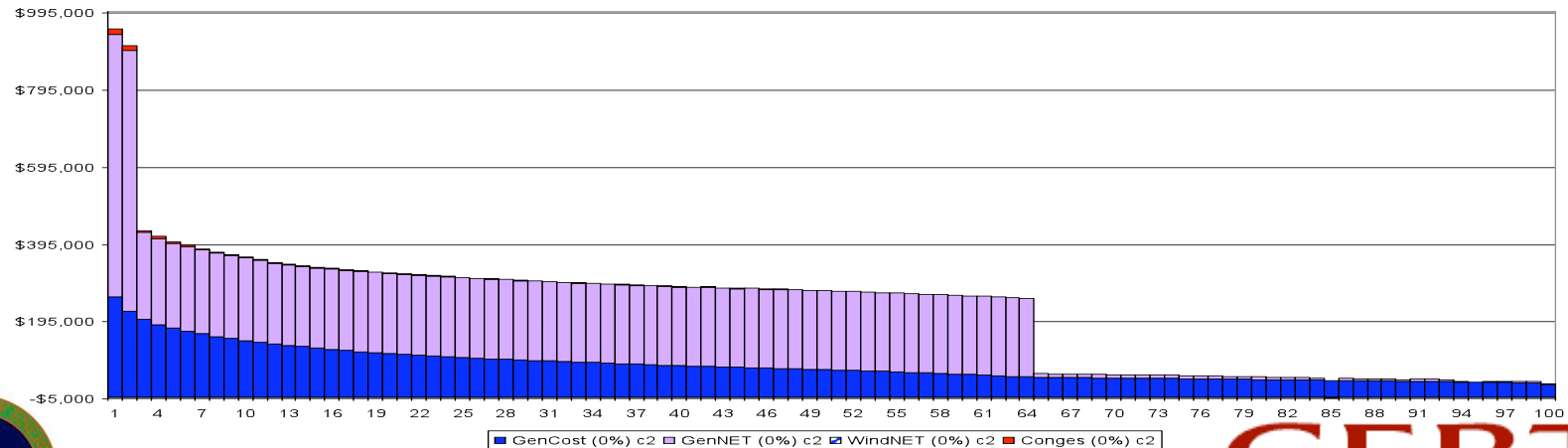
Expected Annual Value Case 1 (0 MW Wind penetration)

No Upgrade



Expected Annual Value Case 2 (0 MW Wind penetration)

Tie Line Upgraded

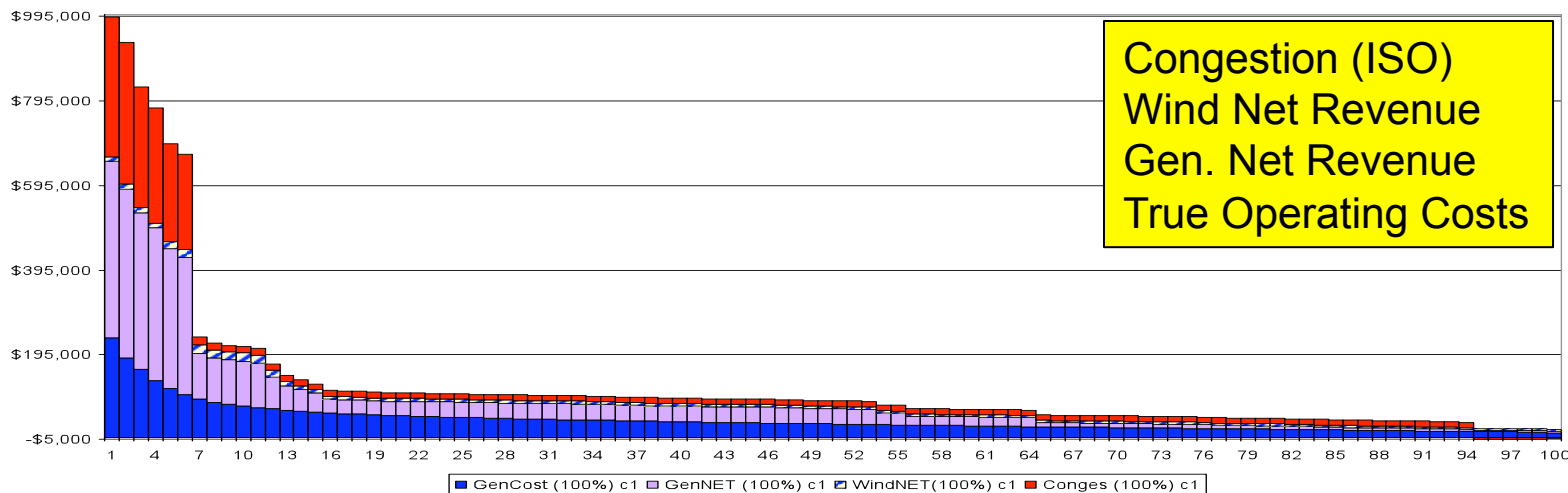


Expected Annual Vales (105 MW of wind)

(High ← Ranked System Load → Low)

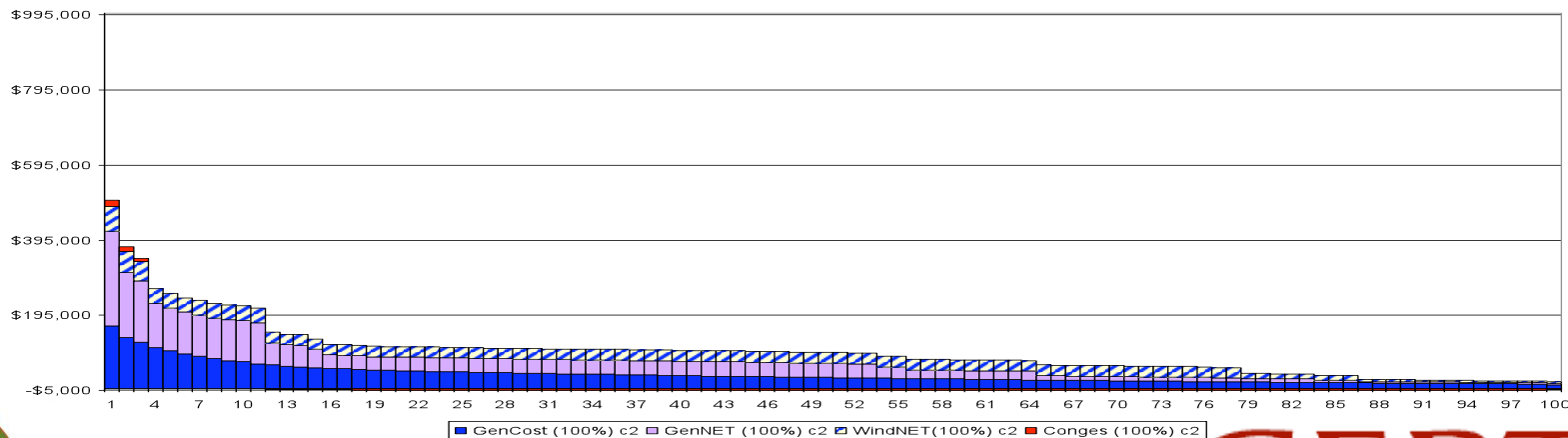
Expected Annual Value Case 1 (105 MW Wind penetration)

No Upgrade



Expected Annual Value Case 2 (105 MW Wind penetration)

Tie Line Upgraded



Maximum Capacities Dispatched at the PEAK System Load

	Case1 ----> Initial System		Case2 ----> Upgrade Tie Line	
	0%*	25%*	0%*	25%*
Gen1	36.37%	43.83%	44.09%	42.71%
Gen2	50.39%	77.89%	45.79%	78.46%
Gen3	99.75%	100.00%	100.00%	100.00%
Gen4	84.36%	89.37%	77.95%	82.98%
Gen5	100.00%	100.00%	100.00%	100.00%
Gen6	96.50%	100.00%	100.00%	100.00%
Wind	0.00%	73.42%	0.00%	91.76%

* 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

	Case1 ----> Initial System		Case2 ----> Upgrade Tie Line	
	0%*	25%*	0%*	25%*
Gen1	0.01%	0.02%	0.01%	0.02%
Gen2	0.04%	0.27%	0.03%	0.24%
Gen3	59.62%	36.04%	59.73%	40.61%
Gen4	57.00%	44.62%	56.60%	29.80%
Gen5	39.65%	24.20%	39.45%	24.59%
Gen6	63.94%	34.46%	64.34%	36.74%
Wind	-	56.18%	-	60.31%

* 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)

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