

The System Costs of Integrating Wind Generation Into Wholesale Electricity Markets.

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OBJECTIVE

Use an integrated economic/engineering framework (the SuperOPF) that determines reserves endogenously to evaluate the effects of:

- 1 Analyzing different case studies to benchmark the effects of wind adoption.
 - Ability to spill wind if necessary.
 - Spillable wind plus storage to reduce the variability of wind generation.
 - Elimination of Network Constraints.
- 2 Including specific costs of deviations in dispatches hour to hour.



Outline

- 1 Structure of the SuperOPF
 - SuperOPF Framework
 - SuperOPF Applications
- 2 Specifications of the test network
 - Test Network and contingencies
 - Wind specification and cases
 - Ramping and reserve costs
- 3 Results of the case study
 - Results Wholesale market
 - Wind Utilization
 - Payments in the Wholesale market
 - Wind and ramping costs in a daily cycle
 - Payments per fuel type



Part 1

Structure of the SuperOPF



What is the SuperOPF?

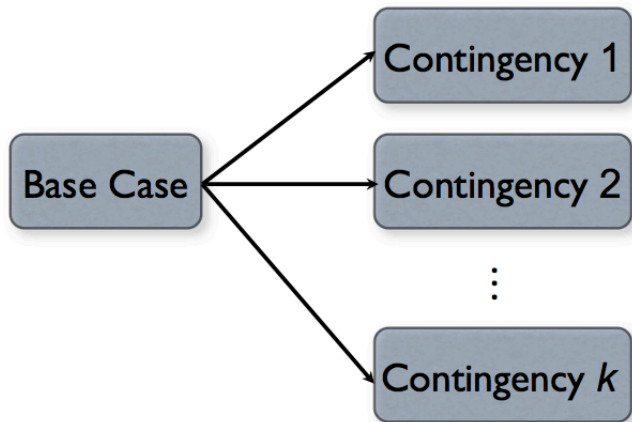
Determining the optimal power flows for operations and planning on an AC network are computationally complex due to many non-linear constraints (Kirchhoff's Laws).

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



Cooptmization

Co-optimization → Minimize the Expected Cost of Dispatch over Different States of the System



The Basic Objective Function

$$\min_{G,R} \sum_{k=0}^K p_k \left\{ \sum_{i=1}^I \left[C_{G_i}(G_{ik}) + C_{R_i}(R_{ik}) \right] + \sum_{j=1}^J VOLL_j LNS(G_k, R_k)_{jk} \right\}$$

Subject to meeting **Load** and all of the nonlinear **AC constraints** of the network.

Where k is a CONTINGENCY

i is a GENERATOR

j is a LOAD

$C_G(G_i)$ is the COST of generating G MWh

$C_R(R_i)$ is the COST of providing R MW of RESERVES

$VOLL_j$ is the VALUE OF LOST LOAD

$LNS(G, R)_{jk}$ is the LOAD NOT SERVED

Capabilities of the SuperOPF

- Determines the commitment of **active and reactive** energy and **geographically distributed up and down reserves** for maintaining Operating Reliability **ENDOGENOUSLY**.
- Puts an **economic cost** on failing to meet standards of Operating Reliability (i.e. shedding load at VOLL)
- Provides a consistent mechanism for subsequent **re-dispatching and pricing** when more information about uncertain quantities is available (Load, Wind Speed).
- The same analytical framework can be used for **Planning** to evaluate System Adequacy



Part 2

Specifications of the test network



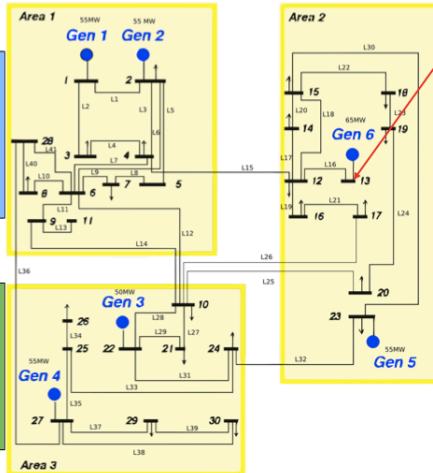
30-BUS TEST NETWORK

Area 1

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

Area 3

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



**Wind Farm
+50MW Wind
35MW Coal**

Area 2

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



Contingencies Considered

0	=	wind 1 (root case)					
1	=	wind 2					
2	=	wind 3					
3	=	wind 4					
							} = 97%
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 from area 3 to area 1)		
10	=	line 15	:	4-12	(main tie from area 2 to area 1)		
11	=	line 12	:	6-10	(other tie from area 3 to area 1)		
12	=	line 14	:	9-10	(other tie from area 3 to area 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 (Case 0)

Wind Scenarios

Three Wind Forecasts with Four Possible Outcomes for each one.

Normal Wind

Forecasted Wind Speed	Probability of Forecast	Wind Output (% of Capacity)	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	2
		100	79

Cases studied

- ① Case 1: **NO** Wind.
- ② Case 1n: **NO** Wind + **No Ramping Cost**
- ③ Case 2: Wind.
- ④ Case 2n: Wind + **No Ramping Cost.**
- ⑤ Case 3: Wind + No Network.
- ⑥ Case 3n: Wind + No Network + **No Ramping Cost.**
- ⑦ Case 4: Constant Potential Wind.
- ⑧ Case 4n: Constant Potential Wind + **No Ramping Cost.**



Ramping and reserve costs

		Fuel Cost(\$/MW)	Gen. (MW)	Avail	Res. (\$/MW)	Cost	Ramp (\$/MW)	Cost
Oil	(p)	95		65		10		0
GCT	(p)	80		45		10		0
CC Gas	(s)	55		40		20		30
NHR	(s)	5		65		20		30
Coal	(b)	25		70		30		60
NHR	(b)	5		50		30		60

Setup ramping costs

For every hour, a two-stage optimization problem was solved.

- First stage (hour-ahead), the dispatches for the next time period ($t + 1$) were determined
- Second stage (real-time), wind realization is known $\rightarrow$ dispatches for the present time period ($t + 1$) were determined with reserves from results of first stage.
- Outputs of each hour were interlinked $\Rightarrow$ set second-stage dispatches for hour t as initial conditions for the dispatch in hour $t + 1$.
- Any deviations above or below previous hour dispatch priced according to the ability of generators to move from their current operating point.

Part 3

Results of the case study



Overview of the Results

	Case 1	Case 1n	Case 2	Case 2n	Case 3	Case 3n	Case 4	Case 4n
Load Paid ^a	336	289	242	242	251	128	231	228
GenCap ^b	224	224	255	273	271	271	225	225
GenEne ^{*, c}	4,713	4,718	4,741	4,738	4,666	4,671	4,734	4,746
MaxWE ^{*, d}	0	0	428	870	612	953	734	966
C.Gen ^e	100	100	91	82	87	80	84	80
LNS	7	7	0	7	7	0	7	7
W.disp(%a)	NA	NA	43	88	62	96	74	98

* 50MW of Wind capacity installed, calculations over 24 hours.

^a \$1,000/day

^b Generation Capacity Needed (MW)

^c Energy Needed to cover load of day (MWh)

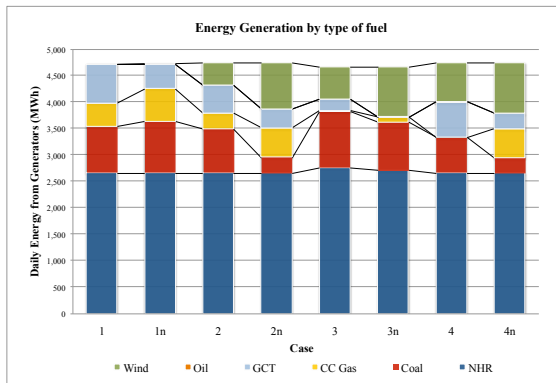
^d Wind Energy Dispatched (MWh)

^e Conventional Generation (%)

Cases

Case 1	NO Wind.	Case 1n	NO Wind + No Ramping Cost
Case 2	Wind.	Case 2n	Wind + No Ramping Cost.
Case 3	Wind + No Network.	Case 3n	Wind + No Network + No Ramping Cost.
Case 4	Constant Potential Wind.	Case 4n	Constant Potential Wind + No Ramping Cost.

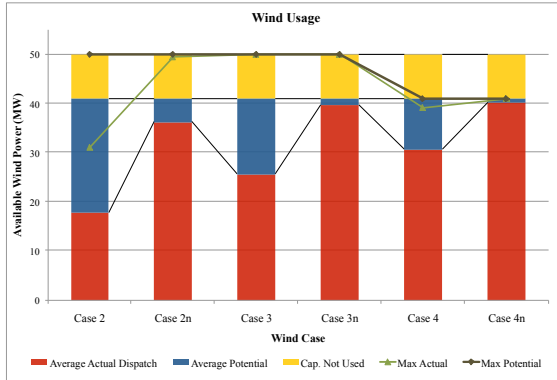
The composition of generation by fuel type



Energy Composition

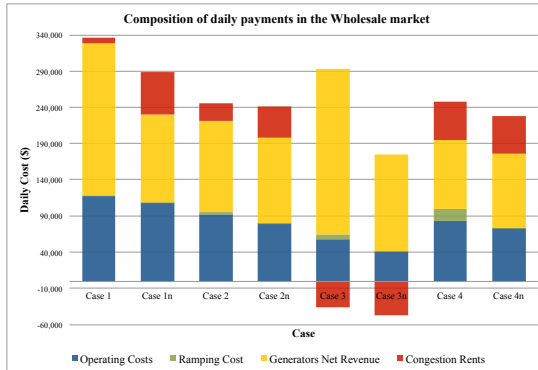
- NHR composition more or less constant.
- Removing Network Constraints and adding a battery → 42 and 71 % higher wind dispatch correspondingly.
- Removing ramping costs → Between 30% and 100 % increase in wind usage.
- Coal is in general the most (negatively) affected.

Wind Utilizations Observed



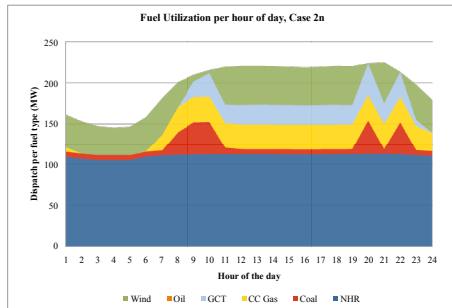
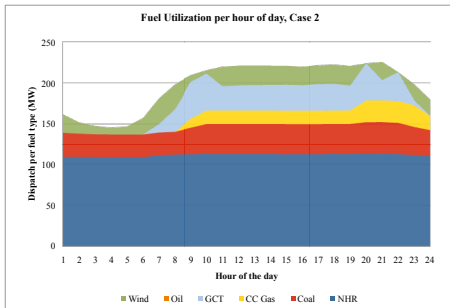
- Case 2 (baseline Wind), maximum dispatch observed 62% of maximum potential wind. Case 4 (Constant Potential Wind) this ratio is 95%.
- Penalization due to wind cutout.
- Eliminating network constraints helps to use higher amounts of wind.

Composition of Payments by customers



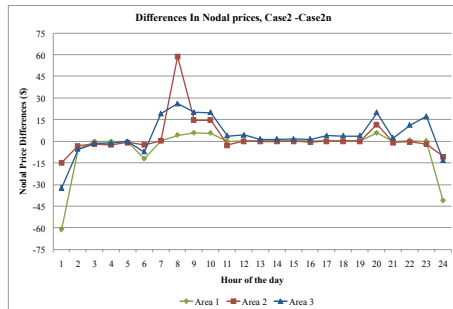
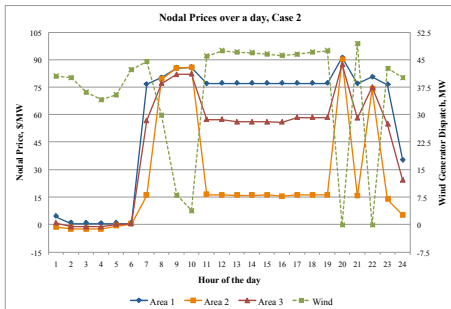
- Case 1 → Case 2 ⇒, ↓ Operating Costs (zero cost wind).
- Case 2 → Case 3 ⇒, ↓ Operating Costs even more. Congestion Rents observed are negative **more missing money for transmission**.
- Case 3 → Case 4 ⇒, ↑ Operating Costs.

Fuel Utilization per hour of day



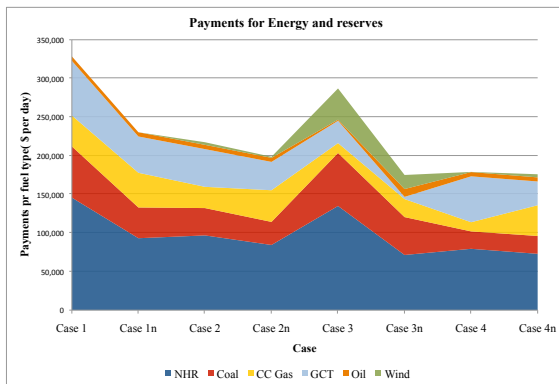
- In Case 2, wind resource is highly utilized. Eliminating ramping costs leads to even higher utilizations.
- Ramping Units differ: in case 2 → GCT. In case 2n → Coal (Generation and ramping combined cost).

Nodal Prices per area and differences (case2-case2n)



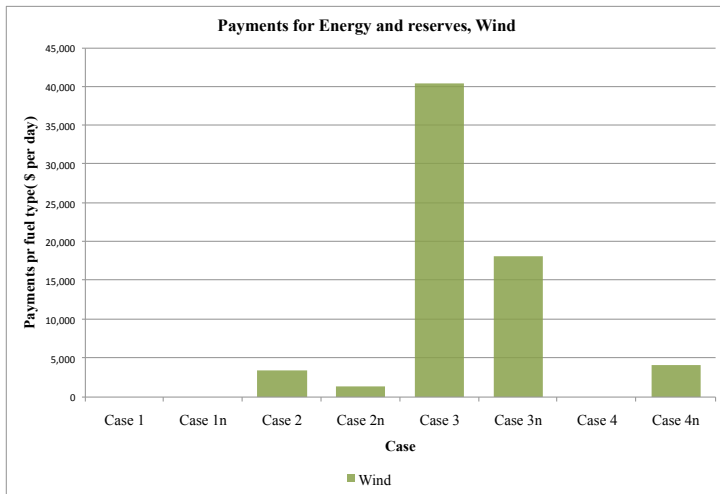
- Clear separation in prices as demand (and therefore congestion) increases.
- When wind disappears, prices 'get together'
- Differences observed in nodal prices observed between case 2 and case 2n driven by wind absence.

The composition of payments by fuel type



- Overall higher payments in case 3 (No Network) lead to higher revenue for wind.
- This is in line with the observed results from overall payments for all fuel types.
- Elimination of ramping constraints always lead to lower payments.
- Ramping units per type of fuel take into account full cost.

Payments for Wind



Conclusions

- Importance of ramping costs for wind dispatches and overall composition of generation in the system
- Wind dispatches is more susceptible to ramping costs than to reserve costs (in line with conclusion above).
- As expected, the cost of running the system is higher in a sequential run. This is due to limitations imposed on maximum available output per generator.
- Maximum amount of wind used observed happens in case of no ramping cost, no cost of reserves with sequential run, using storage.
- Maximum Payment to wind when network constraints are removed. In this case, Nodal prices is uniform over all the system, leading to higher revenue for wind.
- Economic Objective → reduce sum of operating costs **and** ramping costs. Missing Money.
- Observed benefits of storage when including ramping costs (as expected)

