Integration of Contracted Renewable Energy and Spot Market Supply to Serve Flexible Loads

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Outline

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Load Flexibility

3 fundamental approaches to deal with renewable energy variability via demand response

1. Centralized co-optimization of dispatchable supply resources and flexible loads by system operator
2. Price response:
   - Renewable producers bid in centralized real-time market
   - Consumers can communicate with system through instantaneous response to price
3. Coupling aggregated load with renewables:
   - Flexible loads communicate basic needs to renewable suppliers
   - Flexible loads follow dynamic supply signal from renewable resources, system operator faces reduced variability

Research Objective

Want to quantify:

- Renewable energy utilization
- Cost of unit commitment and economic dispatch
- Capital investment in generation capacity

Stochastic unit commitment an appropriate model:

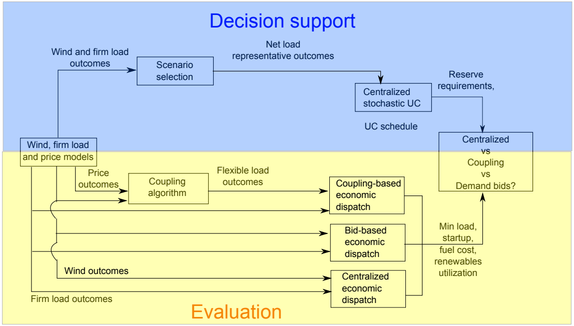
- Quantifies renewable energy utilization (decision variable)
- Quantifies operating costs (objective function)
- Endogenously determines reserves (as opposed to ad hoc rules)

Two-Stage Stochastic Unit Commitment

1. In the first stage we commit slow generators: $u_{gst} = w_{gt}, v_{gst} = z_{gt}, g \in G_s, s \in S, t \in T$ (corresponds to day-ahead market)
2. Uncertainty is revealed: net demand D_{st} = firm demand + deferrable demand - wind power supply
3. Fast generator commitment and production schedules are second stage decisions: $u_{gst}, g \in G_f$ and $p_{gst}, g \in G_f \cup G_s$ (corresponds to real-time market)
4. Objective:

$$\min \sum_{g \in G} \sum_{s \in S} \sum_{t \in T} \pi_s (K_g u_{gst} + S_g v_{gst} + C_g p_{gst})$$

Integrating Demand Response in Stochastic Unit Commitment



Centralized Load Dispatch

- Stochastic unit commitment with demand satisfaction constraint: $\sum_{t=1}^{N} p_{gst} = R$
- Assumptions of centralized load control:
  - Central co-optimization of generation and demand (computationally prohibitive)
  - Perfect monitoring and control of demand
- Centralized load control represents an idealization that can be used for:
  - Quantifying the cost of decentralizing demand response
  - Estimating the capacity savings of deferrable demand

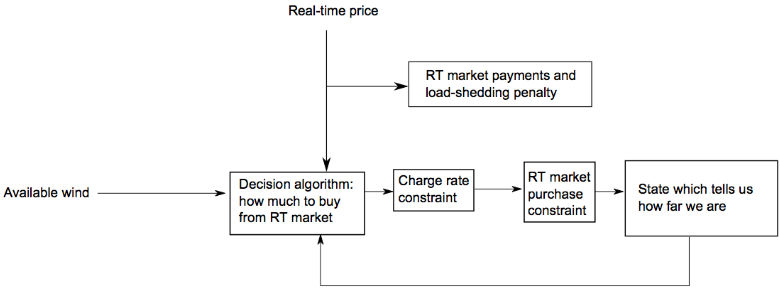
Demand Bids

- Based on retail consumer model of (Borenstein and Holland, 2005), (Joskow and Tirole, 2005), (Joskow and Tirole, 2006)
- State contingent demand functions used in economic dispatch $D_t(\lambda_t; \omega) = a_t(\omega) - \alpha b \lambda^R - (1 - \alpha) b \lambda_t$
- Note that the demand function model has to:
  - Be comparable to the deferrable demand model in terms of total demand R
  - Be consistent with the observed inflexible demand in the system

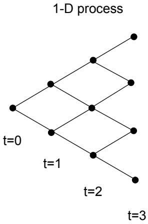
Implementation of Coupling

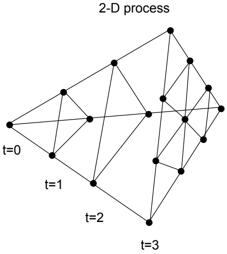
- Match renewable power suppliers to aggregations of flexible consumers
- Consumers specify deadlines for flexible consumption tasks (EV charging, water pumping, refrigeration etc.)
- Aggregators serve deferrable loads primarily from renewable generation assets, possibly resorting to real-time market purchases
- Two types of real-time market participation constraints:
  - Quantity (fuse size)
  - Threshold price (callable forward)

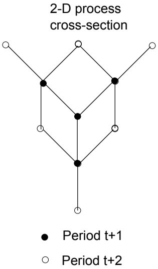
Coupling


Real-time price
RT market payments and load-shedding penalty
Available wind
Decision algorithm: how much to buy from RT market
Charge rate constraint
RT market purchase constraint
State which tells us how far we are

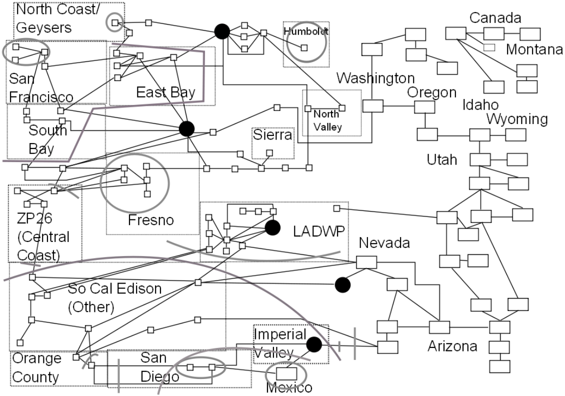
Dynamic Programming on Recombinant Lattices



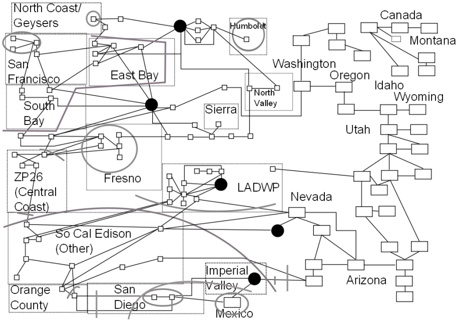




WECC Model


North Coast/ Geysers
Humboldt
Canada
Montana
San Francisco
East Bay
Washington
Oregon
North Valley
Idaho
Wyoming
South Bay
Sierra
Utah
Fresno
ZP26 (Central Coast)
LADWP
Nevada
So Cal Edison (Other)
Imperial Valley
Arizona
Orange County
San Diego
Mexico

Schematic of WECC

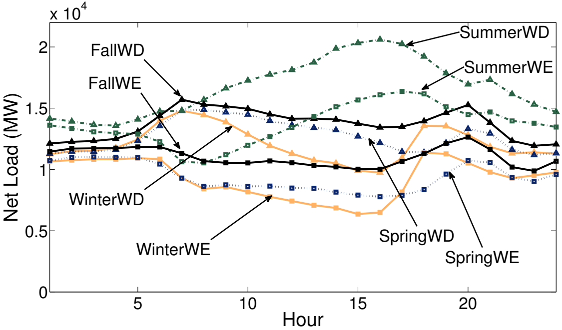


Model Summary

- 124 units (82 fast, 42 slow)
- 53665 MW power plant capacity
- 225 buses
- 375 transmission lines
- 15 scenarios
- Two studies
  - Deep wind integration (14% energy integration, 2020)
  - Moderate wind integration (7% energy integration, 2012)

Day Types

- 8 day types considered, one for each season, one for weekdays/weekends
- Day types weighted according to frequency of occurrence



Data Sources

- Wind power production:
  - California ISO interconnection queue lists locations of planned wind power installations
  - NREL Western Wind and Solar Interconnection Study archives wind speed - wind power for Western US
- Real-time price: California ISO Oasis online database (2004)

Calibration

1. Remove systematic effects:

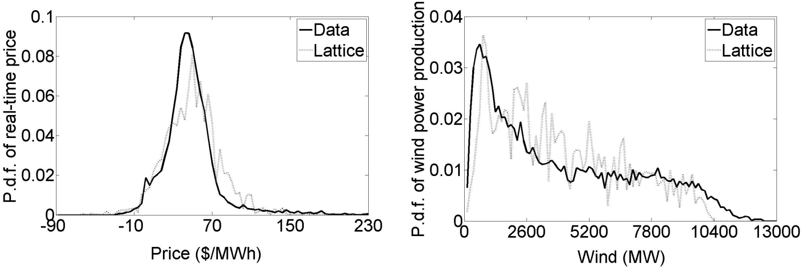
$$y_t^S = \frac{y_t - \hat{\mu}_{mt}}{\hat{\sigma}_{mt}}.$$

2. Transform data to obtain a Gaussian distribution:

$$y_t^{GS} = N^{-1}(\hat{F}(y_t^S)).$$

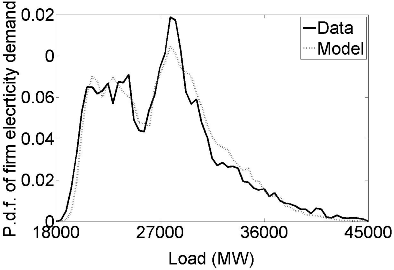
3. Estimate the autoregressive parameters $\hat{\phi}_j$ and covariance matrix $\hat{\Sigma}$ using Yule-Walker equations.

Data Fit


P.d.f. of real-time price
0.1
0.08
0.06
0.04
0.02
0
-90
-10
70
150
230
Price ($/MWh)
Data
Lattice
P.d.f. of wind power production
0.04
0.03
0.02
0.01
0
0
2600
5200
7800
10400
13000
Wind (MW)
Data
Lattice

Firm Demand Uncertainty

- Second order autoregressive model
- Data: California ISO 2004 Oasis database
- Single-area model without transmission constraints



Study Cases

	Zero	Moderate	Deep
Wind capacity (MW)	0	6,688	14,143
DR capacity (MW)	0	5,000	10,000
Daily wind energy (MWh)	0	46,485	95,414
Daily DR energy (MWh)	0	40,000	80,000
DR/firm energy (%)	0	6.1	12.2

Operating Costs and Lost Load

	Daily Cost ($)	Daily Load Shed (MWh)
No wind	**9,012,031**	17.301
Centralized Moderate	**8,677,857**	1.705
Bids Moderate	211,010	609.914
Coupled Moderate	265,128	2.217
Centralized Deep	**8,419,322**	10.231
Bids Deep	578,909	1221.492
Coupled Deep	705,497	112.452

Summary

	Capacity (MW)	Daily Spillage (MWh)
No wind	26,123	N/A
Moderate	26,254	0
Deep	26,789	2

Conclusions

- **Capacity requirements:** For the studied cases, increased load demand is almost fully absorbed by installed wind power capacity.
- **Cost of anarchy:** The cost of anarchy increases from 3.06% to 8.38% as the integration level increases.
- **Demand bids:** Price-responsive demand achieves better cost performance than coupling (2.43% - 6.88% cost increase relative to centralized dispatch) but violates the 1-in-10-years reliability of the system 3.4 to 6.8 times
- **Wind spillage:** Negligible spillage of wind power.

Perspectives

- Price-responsive smart charging
- Stochastic dual dynamic programming algorithm with state-contingent real-time bids
- Transmission constraints
- Parallelization of the model in Lawrence Livermore National Laboratory high performance computing cluster

References

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- A. Papavasiliou, S. S. Oren, *Multi-Area Stochastic Unit Commitment for High Wind Penetration in a Transmission Constrained Network*, submitted to Operations Research.

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- A. Papavasiliou, S. S. Oren, *Integration of Contracted Renewable Energy and Spot Market Supply to Serve Flexible Loads*, 18th World Congress of the International Federation of Automatic Control, Milano, Italy, August 2011.
- A. Papavasiliou, S. S. Oren, *Supplying Renewable Energy to Deferrable Loads: Algorithms and Economic Analysis*, 2010 Power and Energy Society General Meeting, Minneapolis, Minnesota, July 2010.
- A. Papavasiliou, S. S. Oren, *Coupling Wind Generators with Deferrable Loads*, IEEE Energy 2030, Atlanta, Georgia, November 2008.

Thank you

Questions?

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