Stochastic Dispatch Models for Electricity Markets

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Decisions under uncertainty

- Generators, retailers, consumers
  - Bidding
  - Hedging
  - Investing
- System operator / Exchange
  - Transfer capacities
  - Reliability and security constraints
- What about the dispatch problem itself?

Congestion management and balancing

Day-ahead market
with congestion avoidance

e.g.
- Nodal pricing
- Zonal pricing
- (Uniform price)

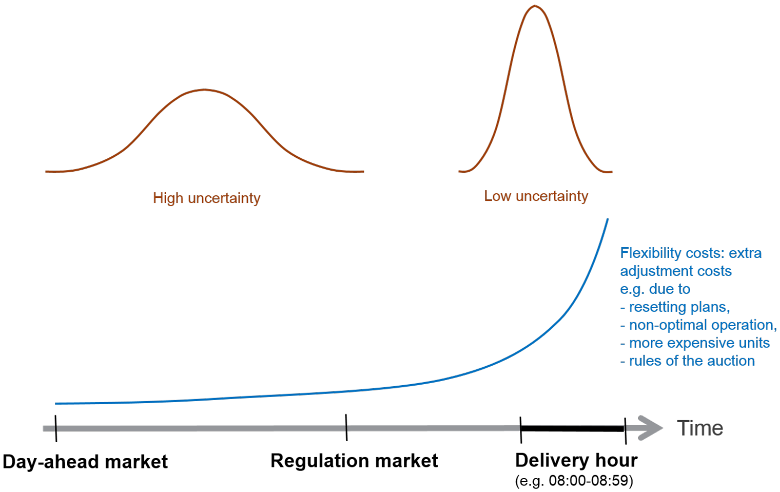
Congestion alleviation

e.g.
- Counter-purchase
- Re-dispatch auction
- Use of reserves list

Reasons for inadequate congestion handling:

- Congestion within areas not considered (in full)
- «Loop-flow» not included in market clearing
- Inadequate representation of capacity constraints

Flexibility costs and uncertainty



Alternative market clearing models

- Integrated stochastic model
  - Pritchard, Zakeri & Philpott (OR, 2010)
- Improved conventional (myopic) dispatch
  - Morales et al. (EJOR, 2014)
- Reserve market
  - Morales et al. (IEEE TPS, 2009 & 2012)

Stochastic market clearing

- Literature:
  - Bouffard et al. (2005a,b); Bouffard and Galiana (2008); Ruiz et al. (2009b,a); Papavasiliou et al. (2011); Papavasiliou and Oren (2012); Khazaei et al. (2014),Bjørndal et al. (2016a,b)
- Pricing issues:
  - Kaye et al. (1990); Wong and Fuller (2007); Pritchard et al. (2010); Morales et al. (2012, 2014); Zavala et al. (2017); Zakeri et al. (2016).

Background

- Our starting point is an energy-only stochastic market clearing as in Pritchard et al. (2010)
  - Compare to a sequential market clearing model with myopic clearing of the day-ahead part of the market
- Organization of bidding and information responsibilities (Bjørndal et al., 2016a)
- How should the day-ahead part of the market be modeled? (Bjørndal et al., 2016b)
  - Network flow and balance constraints
- Pricing (Zakeri et al., 2016)
  - Revenue adequacy for the system operator
  - Cost recovery for generators

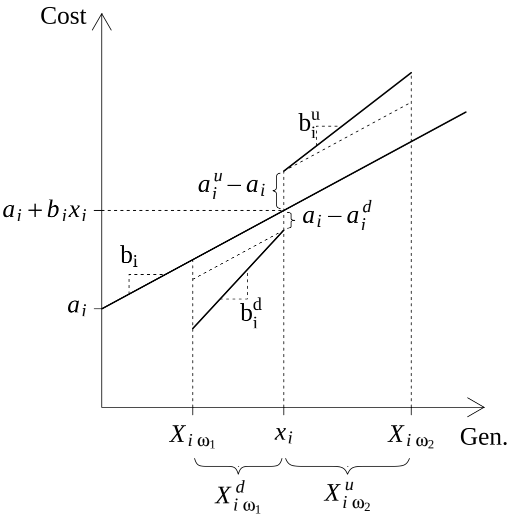
Model

Day-ahead and real-time generation (≥ 0) and load (≤ 0) quantities:

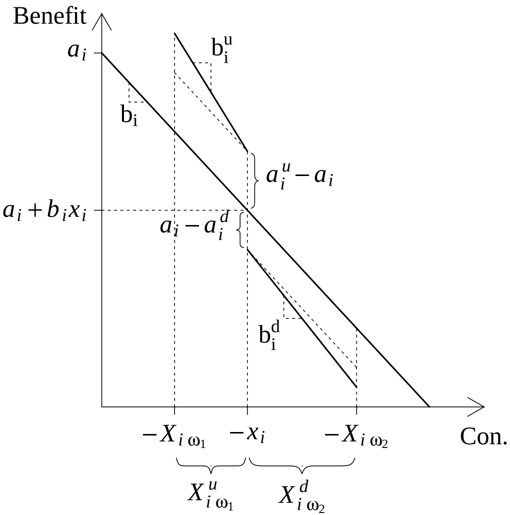
$$x_i \in C_i^1 \qquad \forall i \in I$$
$$X_{i\omega} \in C_i^2(\omega, x_i) \qquad \forall i \in I,\ \omega \in \Omega$$

Upregulation $X_{i\omega}^u = \max\{X_{i\omega} - x_i, 0\}$ or downregulation $X_{i\omega}^d = \max\{x_i - X_{i\omega}, 0\}$ for flexible entities.

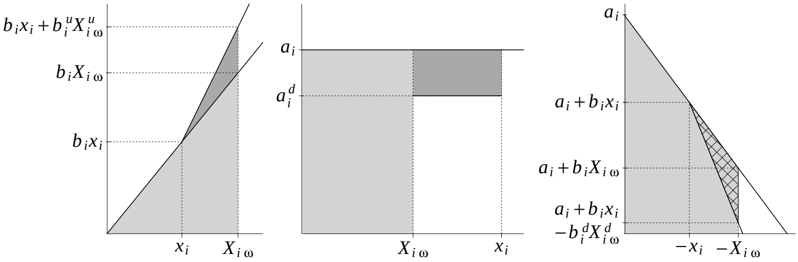
Generator cost functions



Load benefit curves



Examples of bid curves



Objective function

Cost of real-time quantity at day-ahead parameters:

$$c_i(X_{i\omega}) = a_i X_{i\omega} + 0.5 b_i (X_{i\omega})^2$$

Flexibility cost:

$$\begin{aligned}\tilde{c}_i(x_i, X_{i\omega}) =& (a_i^u - a_i) X_{i\omega}^u + 0.5(b_i^u - b_i)(X_{i\omega}^u)^2 \\ & + (a_i - a_i^d) X_{i\omega}^d + 0.5(b_i^d - b_i)(X_{i\omega}^d)^2\end{aligned}$$

Stochastic market clearing model

$$\min_{x,f,X,F} \; \mathbb{E}\left[\sum_{i\in I}\Big(c_i(X_i) + \tilde{c}_i(x_i, X_i)\Big)\right] \quad (1a)$$

s.t.

$$x_i \in C_i^1 \qquad \forall i \in I \quad (1b)$$

$$X_{i\omega} \in C_i^2(\omega, x_i) \qquad \forall i \in I,\ \omega \in \Omega \quad (1c)$$

$$\tau_n(f) + \sum_{i\in I(n)} x_i = 0 \qquad \forall n \in N \qquad [\pi_n] \quad (1d)$$

$$\tau_n(F_\omega) + \sum_{i\in I(n)} X_{i\omega} = 0 \qquad \forall n \in N,\ \omega \in \Omega \qquad [p_\omega \lambda_{n\omega}] \quad (1e)$$

$$f \in U^1 \quad (1f)$$

$$F_\omega \in U^2 \qquad \forall \omega \in \Omega \quad (1g)$$

Myopic market clearing model - day-ahead part

$$\min_{x,f} \sum_{i \in I} c_i(x_i) \tag{2a}$$

s.t.

$$x_i \in C_i^1 \qquad \forall i \in I \tag{2b}$$

$$\tau_n(f) + \sum_{i \in I(n)} x_i = 0 \qquad \forall n \in N \qquad [\pi_n] \tag{2c}$$

$$f \in U^1 \tag{2d}$$

Myopic market clearing model - real-time part, scenario ω

$$\min_{X_\omega, F_\omega} \sum_{i \in I} \Big(c_i(X_{i\omega}) + \tilde{c}_i(x_i, X_{i\omega}) \Big) \tag{3a}$$

s.t.

$$X_{i\omega} \in C_i^2(\omega, x_i) \qquad \forall i \in I \tag{3b}$$

$$\tau_n(F_\omega) + \sum_{i \in I(n)} X_{i\omega} = 0 \qquad \forall n \in N \qquad [\lambda_{n\omega}] \tag{3c}$$

$$F_\omega \in U^2 \tag{3d}$$

Stochastic market clearing model

$$\min_{x,f,X,F} \mathbb{E}\left[\sum_{i\in I}\left(c_i(X_i)+\tilde{c}_i(x_i,X_i)\right)\right] \tag{1a}$$

s.t.

$$x_i \in C_i^1 \quad \forall i \in I \tag{1b}$$

$$X_{i\omega} \in C_i^2(\omega, x_i) \quad \forall i \in I,\ \omega \in \Omega \tag{1c}$$

$$\tau_n(f) + \sum_{i\in I(n)} x_i = 0 \quad \forall n \in N \quad [\pi_n] \tag{1d}$$

$$\tau_n(F_\omega) + \sum_{i\in I(n)} X_{i\omega} = 0 \quad \forall n \in N,\ \omega \in \Omega \quad [p_\omega \lambda_{n\omega}] \tag{1e}$$

$$f \in U^1 \tag{1f}$$

$$F_\omega \in U^2 \quad \forall \omega \in \Omega \tag{1g}$$

Day-ahead constraints

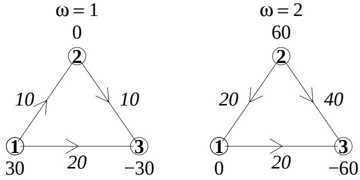
- We assume that U^2 represents the network constraints in a DC load flow model without losses
- What should U^1 represent?

Alternative day-ahead network representations

1. Nodal model, i.e., $U^1 = U^2$
2. Zonal model
   - No loop flow
   - Aggregate flow capacities set by system operator(s)
3. Unconstrained flow, i.e., $U^1 = \mathbb{R}^{|L|}$
4. Unconstrained flow and balance

$$\min[v_{nodal}^{stoch}, v_{zonal}^{stoch}] \geq v_{bal}^{stoch} \geq v_{unc}^{stoch}$$

Example 1

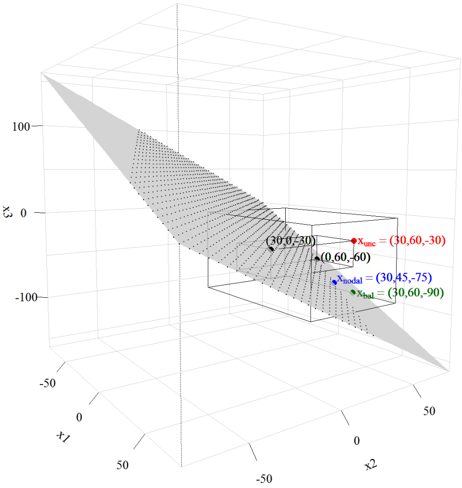


- $P(1) = P(2) = 0.5$
- Real-time quantities X_ω are given above
- All cost parameters equal zero, except $a_1^u = a_2^u = 1$ and $a_3^u = 0.25$
- All lines have identical impedances
- Capacity of line (2,3) is 40

Example 1 - stochastic model

$$\begin{aligned}
\min\ & 0.5 \cdot 1 \cdot \left([30 - x_1]^+ + [0 - x_1]^+ + [0 - x_2]^+ + [60 - x_2]^+\right) \\
& + 0.5 \cdot 0.25 \cdot \left([-30 - x_3]^+ + [-60 - x_3]^+\right) \\
\text{s.t.}\ & \\
& x_1 + x_2 + x_3 = 0 \\
& -40 \leq \frac{x_2 - x_3}{3} \leq 40
\end{aligned}$$

Example 1 - optimal day-ahead schedules

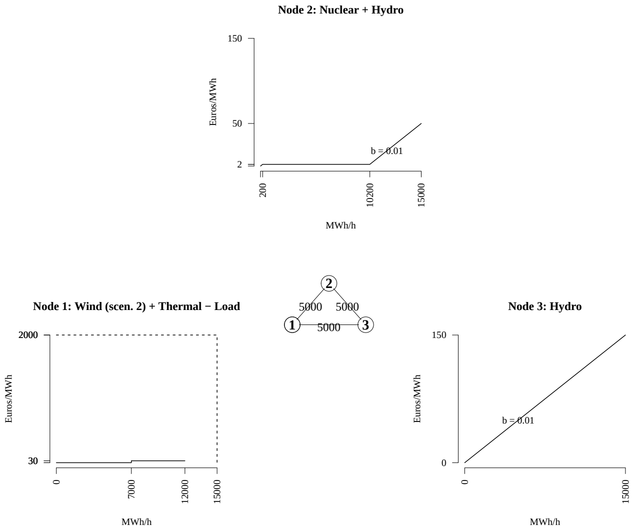


$$v_{unc}^{stoch} = 0$$

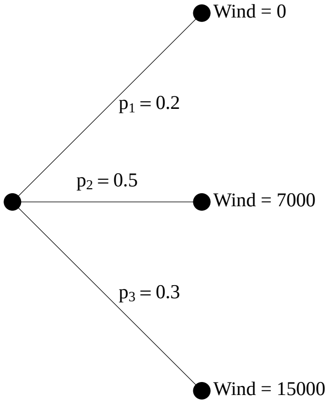
$$v_{bal}^{stoch} = 0.5 \cdot (-30 - (-90)) \cdot 0.25 + 0.5 \cdot (-60 - (-90)) \cdot 0.25 = 11.25$$

$$v_{nodal}^{stoch} = 0.5 \cdot (-30 - (-75)) \cdot 0.25 + 0.5 \cdot \Big[(60 - 45) \cdot 1 + (-60 - (-75)) \cdot 0.25\Big] = 15$$

Example 2


Node 2: Nuclear + Hydro
150
50
2
Euros/MWh
b = 0.01
200
10200
15000
MWh/h
2
5000
5000
1
5000
3
Node 1: Wind (scen. 2) + Thermal − Load
2000
30
Euros/MWh
0
7000
12000
15000
MWh/h
Node 3: Hydro
150
0
Euros/MWh
b = 0.01
0
15000
MWh/h

Wind scenarios



Cost and benefit parameters

Entity	Node	Intercept (a)	Slope (b)	Flexible?	Flex. cost up	Flex. cost down
Wind	1	0	0	Partly	$a^u = a$	$a^d = a$
Therm.	1	30	0	Yes	$a^u = a + 6$	$a^d = a$
Load	1	2000	0	Yes[1]	$a^u = a$	$a^d = a$
Nucl.	2	2	0	No	-	-
Hydro	2	0	0.01	Yes	$b^u = 10b$	$b^d = b$
Hydro	3	0	0.01	Yes	$b^u = 10b$	$b^d = b$

[1] Load can be shed at VOLL $= a =$ 2000 Euros / MWh.

Example 2 - optimal values, stochastic model

	$\mathbb{E}[c]$		$\mathbb{E}[\tilde{c}]$		$\mathbb{E}[c+\tilde{c}]$	
Model	€	Relative	€	Relative	€	Relative
Wait-and-see	66360	100.0 %	0	0.0 %	66360	100.0 %
Unconstrained	76250	114.9 %	0	0.0 %	76250	114.9 %
Balanced	76322	115.0 %	1600	2.4 %	77922	117.4 %
Nodal	82325	124.1 %	2190	3.3 %	84515	127.4 %
Zonal ($cap_{\{1\},\{2,3\}} = 5000$)	116977	176.3 %	117168	176.6 %	234144	352.8 %
Zonal ($cap_{\{1\},\{2,3\}} = 10000$)	79810	120.3 %	2769	4.2 %	82578	124.4 %

Example 2 - optimal schedules

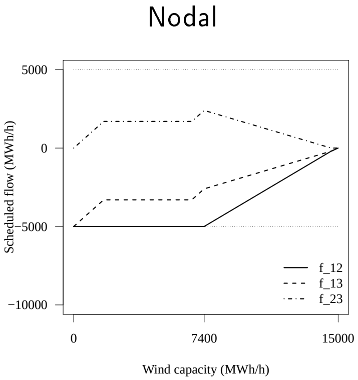
Entity	Node	Nodal model				Unconstrained model			
		Day-ahead schedule	Real-time adj. Low	Medium	High	Day-ahead schedule	Real-time adj. Low	Medium	High
Wind	1	153	-153	6847	9849	0		7000	10000
Therm.	1	5000		-5000	-5000	5000		-5000	-5000
Load	1	-15000				-15000			
Nucl.	2	4998				5000			
Hydro	2	155	-153	245	-155	1500	-1500		-1500
Hydro	3	4694	306	-2092	-4694	5000		-3500	-5000
Total		0	0	0	0	1500	-1500	-1500	-1500

- We see that the unconstrained model overbooks generation

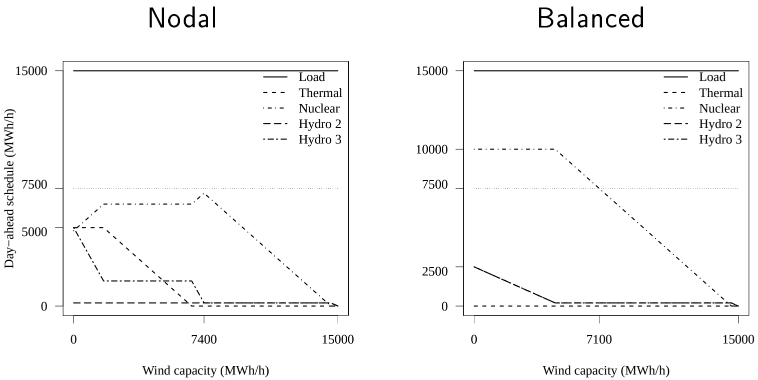
Myopic model

- Solutions depend on wind power bids in day-ahead market
- Removing constraints in the day-ahead market may lead to infeasibilities, e.g. due to scheduling of non-flexible nuclear in day-ahead market

Myopic model - scheduled flow



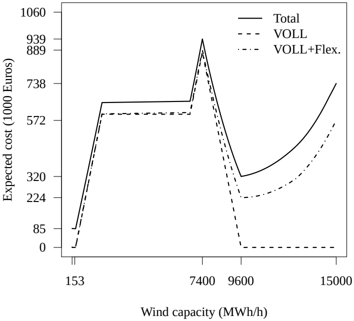
Myopic model - scheduled generation



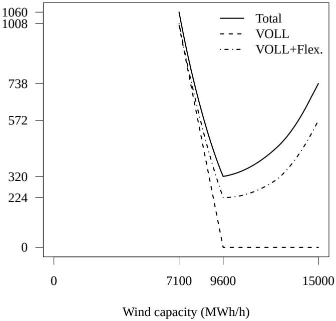
- Too much inflexible generation is scheduled with balanced model

Myopic model - expected cost

Nodal

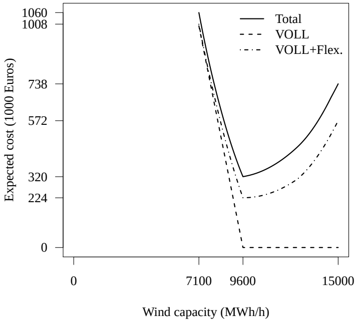


Balanced

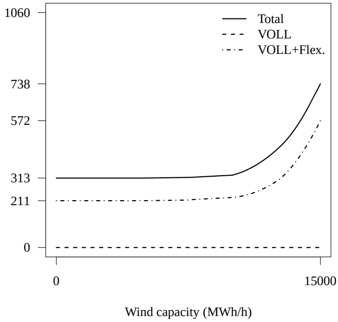


Myopic zonal model - expected cost

$cap_{\{1\},\{2,3\}} = 10000$



$cap_{\{1\},\{2,3\}} = 5000$



Pricing (Zakeri et al., 2016)

- The pricing scheme in Pritchard et al. (2010) is revenue adequate in expectation.
- Mathematically this means

$$E\left[\sum_i \left(x_i^*\pi_{n(i)} + (X_i^* - x_i^*)\lambda_{n(i)}\right)\right] \leq 0.$$

(recall payout is positive and collection is negative).

- Intuitively this means that, if this type of market is used repeatedly over many trading periods, the SO will not run a financial deficit over time.
- There may be a deficit in an individual trading period.

Revenue adequacy

- NewSP is revenue adequate in every scenario.
- Mathematically this means for any scenario ω, at optimality

$$\sum_i \left(X_i^\omega \pi_{n(i)}^\omega - d_{n(i)}^\omega \pi_{n(i)}^\omega \right) \leq 0.$$

(recall payout is positive and collection is negative).

- This is natural and the argument is very similar to revenue adequacy of the DCOPF.

Cost recovery in expectation

- NewSP recovers cost for each tranche, including the deviation penalties, in expectation.
- Mathematically this means at optimality

$$E\left[\pi^{\omega}_{n(i)} X^{\omega}_{i} - c_i X^{\omega}_{i} - r_{U\,i} u^{\omega}_{i} - r_{V\,i} v^{\omega}_{i}\right] \geq 0.$$

- This result follows from SP duality and a technical lemma proving the validity of duals in real time.

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