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Faculty of Business Administration and Economics
International Ruhr Energy Conference 2015 (INREC 2015)
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Essen, March 23.-25. 2015
5TH INREC CONFERENCE 2015
Energy Markets – Risks of Transformation and Disequilibria
Conference Objective
The energy markets are undergoing rapid changes – intended transformation processes like the German Energiewende and unexpected shifts like the substantial drop in oil prices since June 2014. These changes provide opportunities and advantages, but they also pose new challenges and risks for companies and governments. The conference provides a unique, interdisciplinary forum to discuss new methods and approaches for modeling and coping with these transformations and the associated opportunities, disequilibria and risks. Contributions are particularly welcome that build the bridge between theoretically sound models and practically relevant applications.
Conference themes and topics
· Energy Price Modeling
· Trading in Commodity Markets
· Energy Market (Dis-)Equilibria
· Fluctuation Renewabels & Markets
· Energy Risk Management
· Energy Innovations & Energy Markets
· Energy Grids and Markets
Chair for Management Science and Energy Economics
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TECHNISCHE UNIVERSITÄT WIEN
Vienna University of Technology

Efficient Reserve Capacity Prices in Electricity Balancing Markets with Long-term Contracts

5th INREC conference 2015

Energy Markets – Risks of Transformation and Disequilibria

23th March 2015

DI André Ortner
Vienna University of Technology, Energy Economics Group

Mag. Dr. Christoph Graf
Florence School of Regulation – Climate, European University Institute (EUI)

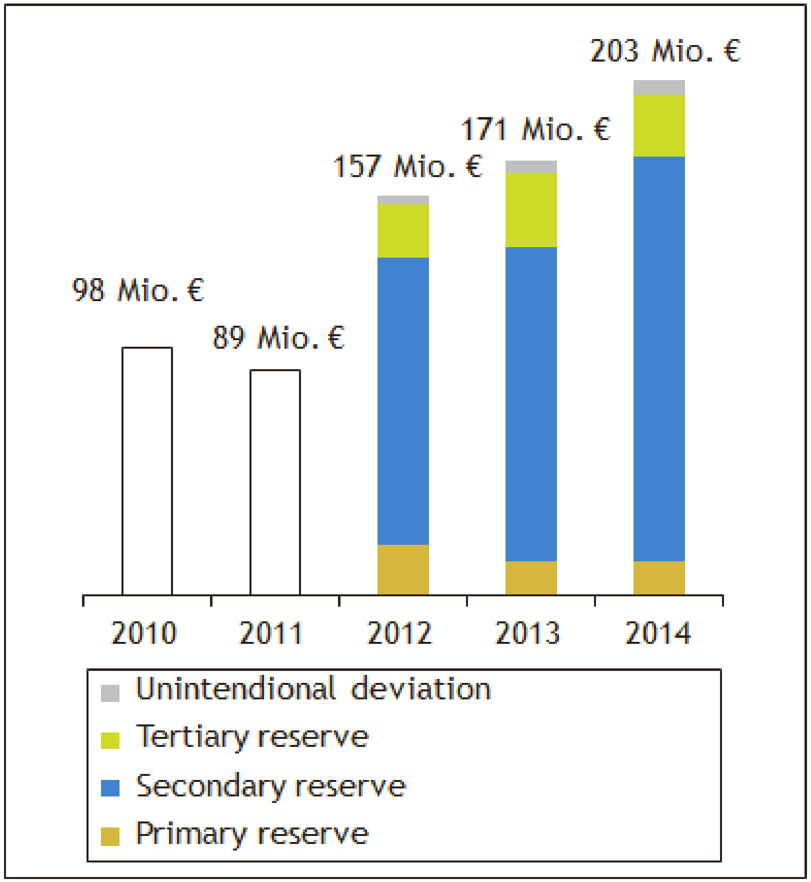
Energy Economics Group

European University Institute

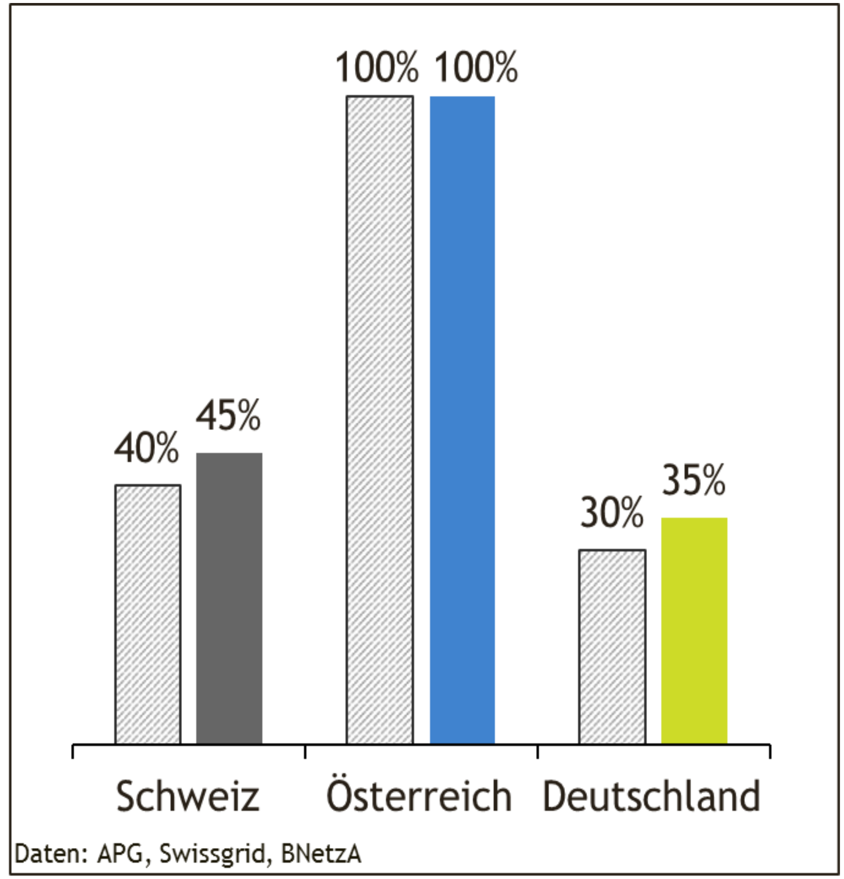
ROBERT SCHUMAN CENTRE FOR ADVANCED STUDIES

Motivation: Content-related

Costs in the Austrian balancing electricity market constantly rising since liberalization



Specific costs (2012 and 2013) are comparatively high relative to neighbour countries

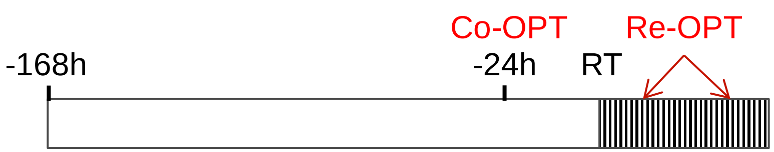


Motivation: Methodology-related

Integrated systems	Unbundled systems

Integrated systems

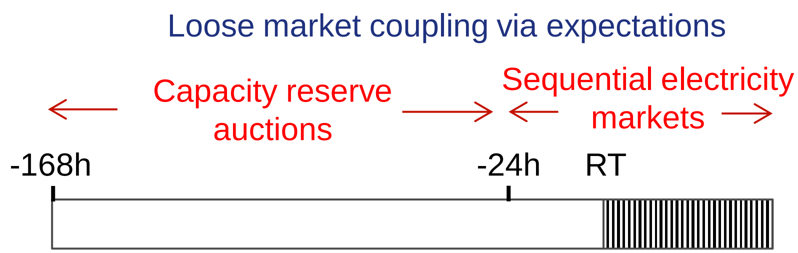
- Mandatory obligation to participate (suppliers)
- Forward (day-ahead) optimization of <u>all</u> generation, transmission and reserves simultaneously
- Optimization includes intertemporal factors (start-up commitments, ramping rates, reservoirs' potential)
- Pricing and settlement is based on system-wide opportunity costs (shadow variables of system constraints)
- Multi-part bid and compensation format



- Xingwang Ma (1999), Wu (2004), Cheung (2000), Gan (2003), Zheng (2006), Ehsani (2009), Azadani (2010)
- PJM, NYISO, ERCOT, …

Unbundled systems

- Voluntary participation (except for must-run and local reliability)
- Independent clearing of markets for energy, transmission and reserves (no explicit coordination)
- One single (linear) clearing price for energy (Intertemporal costs and constraints are not included explicitly and must be internalized by participants)
- Explicit (forward) auction markets for capacity reserves



- Just and Weber (2008), Just and Weber (2011), Heim (2011), Ritter (2012)
- California, Australia, most European markets

Methodology

Providing capacity reserves: Definition of costs

The costs of each generator i for providing positive $C_i^{B\uparrow}$ and negative reserve capacity $C_i^{B\downarrow}$ result from two different cost components: *opportunity* cost and *must-run* cost (Just und Weber 2008, Müsgens 2014)

$$C_i^{B\uparrow} = p_i^{B\uparrow,OC} \cdot Q_i^{B\uparrow} + p_i^{B\uparrow,MR} \cdot \underline{Q_i} \quad \forall i \in B\uparrow$$

$$C_i^{B\downarrow} = p_i^{B\downarrow,MR} \cdot \left(Q_i^{B\downarrow} + \underline{Q_i}\right) \quad \forall i \in B\downarrow .$$

In a perfectly competitive market each generator i would bid exactly the sum of opportunity and must-run cost in the reserve power auction.

Methodology

Providing capacity reserves: Definition of prices

We formalize the composition of the capacity reserve price components through

$$p_i^{B\uparrow,OC} \cdot Q_i^{B\uparrow} = \sum_t \int_{q_{it}-Q_i^{B\uparrow}}^{q_{it}} \Big(p_t^S(q) - c_i(q)\Big)^+ dq$$

$$p_i^{B\uparrow,MR} \cdot \underline{Q}_i = p_i^{B\downarrow,MR} \cdot \Big(\underline{Q}_i + Q_i^{B\downarrow}\Big) = \sum_t \int_0^{\underline{Q}_i} \Big(c_i(q) - p_t^S(q)\Big)^+ dq$$

To further simplify we linearize the model through the assumption of linear cost functions, the price-taker assumption(perfect competition). Through the former definition of costs we now derive the capacity reserve prices

$$p_i^{B\uparrow} = \sum_t (p_t^S - c_i)^+ + \sum_t (c_i - p_t^S)^+ \cdot \frac{\underline{p} \cdot \overline{Q}_i}{Q_i^{B\uparrow}}, \quad \forall i \in B\uparrow$$

$$p_i^{B\downarrow} = \sum_t (c_i - p_t^S)^+ \cdot \left(1 + \frac{\underline{p} \cdot \overline{Q}_i}{Q_i^{B\downarrow}}\right), \quad \forall i \in B\downarrow.$$

Methodology

Linearization of must-run conditions

Through linearization of the must-run conditions (spinning reserves)

$$\begin{aligned} q_{it}^S &\geq \underline{p}_i \cdot z_i^{B\uparrow} \cdot \overline{Q_i}, && \forall t \text{ and } i \in B\uparrow \\ q_{it}^S &\geq \underline{p}_i \cdot z_i^{B\downarrow} \cdot \overline{Q_i} + Q_i^{B\downarrow}, && \forall t \text{ and } i \in B\downarrow \end{aligned} \quad \Longrightarrow \quad \begin{aligned} q_{it}^S &\geq \underline{p}_i \cdot Q_i^{B\uparrow} \\ q_{it}^S &\geq (1+\underline{p}_i) \cdot Q_i^{B\downarrow} \end{aligned}$$

Now we can write the cost/price equations in a linear form as

$$C_i^{B\uparrow} \simeq \left(\sum_t \left(p_t^S - c_i\right)^+ + \sum_t \left(c_i - p_t^S\right)^+ \cdot \underline{p}_i \right) \cdot Q_i^{B\uparrow} = p_i^{B\uparrow} \cdot Q_i^{B\uparrow}$$

$$C_i^{B\downarrow} \simeq \left(\sum_t \left(1+\underline{p}_i\right) \cdot \left(c_i - p_t^S\right)^+ \right) \cdot Q_i^{B\downarrow} = p_i^{B\downarrow} \cdot Q_i^{B\downarrow}$$

Methodology

Lower level

Simple linear power dispatch model minimizing the variable generation costs c_i^S of all generators i over the planning horizon T.

$$\min_{q^S} \sum_{i,t} c_i^S \cdot q_{it}^S$$

The constraints of the thermal units are restricted through

$$\begin{aligned} q_{it}^S + Q_i^{B\uparrow} - \overline{Q}_i &\leq 0 \quad (\lambda_{it}^1) \\ \underline{p}_i \cdot Q_i^{B\uparrow} - q_{it}^S &\leq 0 \quad (\lambda_{it}^2) \\ (1 + \underline{p}_i) \cdot Q_i^{B\downarrow} - q_{it}^S &\leq 0 \quad (\lambda_{it}^3) \end{aligned}$$

thus incorporating next to the maximum technical limits of the generation units also withholding and must-run conditions of providing spinning reserves. System demand fullfillment in all hours leading to

$$\sum_i q_{it}^S - d_t^S = 0 \quad (p_t^S)$$

Methodology

Lower level vs. Co-optimization approach

Simple linear power dispatch model minimizing the variable generation costs c_i^S of all generators i over the planning horizon T.

$$\min_{q^S, Q^{B\uparrow}, Q^{B\downarrow}} \sum_{i,t} c_i^S \cdot q_{it}^S$$

The constraints of the thermal units are restricted through

$$\begin{aligned} q_{it}^S + Q_i^{B\uparrow} - \overline{Q}_i &\leq 0 \quad (\lambda_{it}^1) \\ \underline{p}_i \cdot Q_i^{B\uparrow} - q_{it}^S &\leq 0 \quad (\lambda_{it}^2) \\ (1 + \underline{p}_i) \cdot Q_i^{B\downarrow} - q_{it}^S &\leq 0 \quad (\lambda_{it}^3) \end{aligned}$$

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$$\sum_i q_{it}^S - d_t^S = 0 \quad (p_t^S)$$

$$Q_i^{B\uparrow} - \overline{Q_i^{B\uparrow}} \leq 0 \quad (\beta_i^{B\uparrow}) \qquad \sum_i Q_i^{B\uparrow} - D^{B\uparrow} = 0 \quad (\overline{p^{B\uparrow}})$$

$$Q_i^{B\downarrow} - \overline{Q_i^{B\downarrow}} \leq 0 \quad (\beta_i^{B\downarrow}) \qquad \sum_i Q_i^{B\downarrow} - D^{B\downarrow} = 0. \quad (\overline{p^{B\downarrow}})$$

Reserve capacities as endogenous model variables

Methodology

The dual problem of the Co-Optimization problem is

$$\max_{\lambda^1_{it},\lambda^2_{it},\lambda^3_{it},p^S_t,\beta^{B\uparrow}_i,\beta^{B\downarrow}_i,\overline{p^{B\uparrow}},\overline{p^{B\downarrow}}\in\mathbb{R}+} \sum_i \Pi_i$$

$$\Pi_i = \sum_t (d^S_t \cdot p^S_t - \lambda^1_{it} \cdot \overline{Q}_i) + D^{B\uparrow} \cdot \overline{p^{B\uparrow}} - \overline{Q^{B\uparrow}_i} \cdot \beta^{B\uparrow}_i + D^{B\downarrow} \cdot \overline{p^{B\downarrow}} - \overline{Q^{B\downarrow}_i} \cdot \beta^{B\downarrow}_i$$

subject to the constraints

$$c^S_i + \lambda^1_{it} - \lambda^2_{it} - \lambda^3_{it} - p^S_t \geq 0, \forall i, t$$

$$\sum_t (\lambda^1_{it} + \gamma^{min}_i \cdot \lambda^2_{it}) + \beta^{B\uparrow}_i - \overline{p^{B\uparrow}} \geq 0, \forall i$$

$$\sum_t ((1 + \gamma^{min}_i) \cdot \lambda^3_{it}) + \beta^{B\downarrow}_i - \overline{p^{B\downarrow}} \geq 0, \forall i$$

Derivations of the Lagrangian function of the primal problem reveal

$$0 \leq \lambda^1_{it} = \frac{\partial \mathcal{L}}{\partial g(q^S_{it}, Q^{B\uparrow}_i)} = p^S_t - c^S_i |_{Q^{B\uparrow}=const}$$

$$0 \leq \lambda^{2,3}_{it} = \frac{\partial \mathcal{L}}{\partial g(q^S_{it}, Q^{B\uparrow}_i), Q^{B\downarrow}_i)} = c^S_i - p^S_t |_{Q^{B\uparrow,B\downarrow}=const}$$

When substituting this into reserve price equations we get

$$\overline{p^{B\uparrow}} \leq p^{B\uparrow}_i + \beta^{B\uparrow}_i, \forall i \quad \text{with} \quad p^{B\uparrow}_i = \sum_t \lambda^1_{it} + \underline{p}_i \cdot \lambda^2_{it}$$

$$\overline{p^{B\downarrow}} \leq p^{B\downarrow}_i + \beta^{B\downarrow}_i, \forall i \quad \text{with} \quad p^{B\downarrow}_i = \sum_t (1 + \underline{p}_i) \cdot \lambda^3_{it}$$

Co-optimization approach valid?

The dual variables of the Co-optimization problem are proxies for efficient capacity reserve prices resulting from long-run auctions under the following conditions:

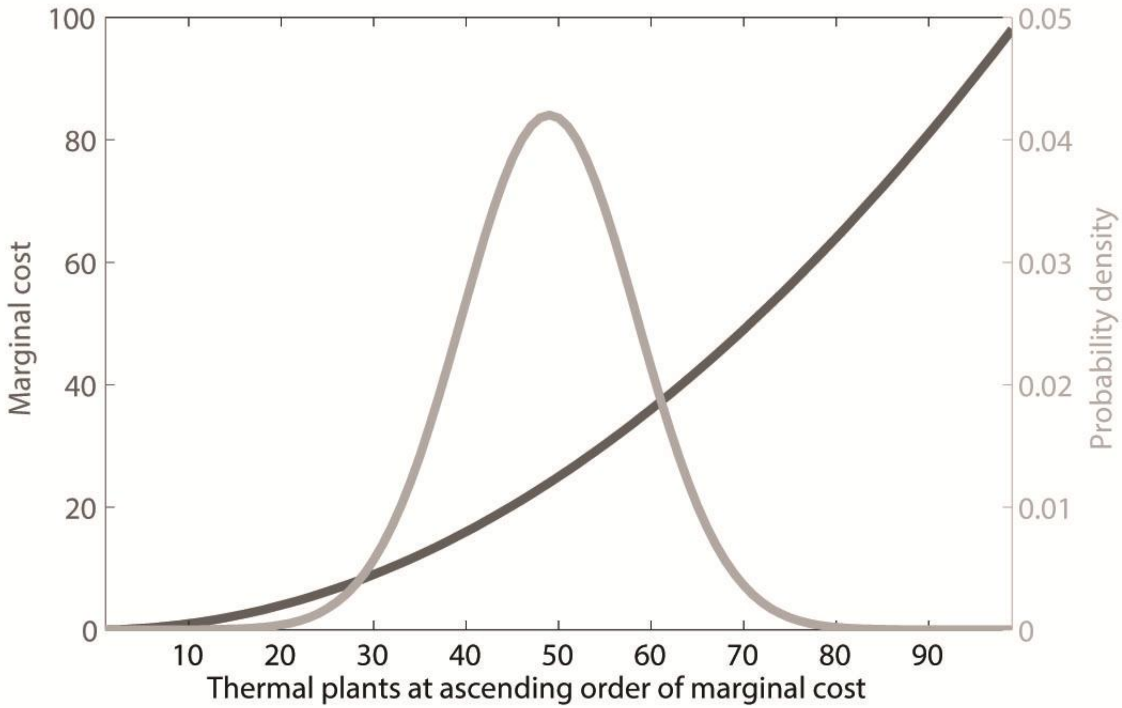
- The spot market and the capacity reserve auction is perfectly competitive and a market equilibrium prevails.
- All participants behave rationally and internalize their costs based on the same methodology into their auction bids.
- We interpret the input parameters of the model as a forecast common to all auction participants on which basis they calculate bids in order to reflect their true cost of providing reserves.
- We assume the same ability of auction participants to anticipate how their actions and the corresponding reactions of other participants influence their costs of providing reserves.

-> Assumptions are strong and do not generally hold in European balancing electricity markets

-> Impact of rejecting assumptions is still an underesearched topic

Model calibration

We use a simple study model



Case description and assumptions

- Hourly model over 1 week (168 h)
- Normal distributed demand (no intertemporal relations considered -> residual demand)
- 97 – 100 thermal power plants with linear marginal costs a step-wise quadratic
- All plants have a capacity of 1 and do not face and individual flexibility constraints
- 1 – 3 pumped hydro storages in different configurations
- Exogenous demand for positive and negative reserves (= 20 in basic scenarios)
- All plants are able to provide reserves

Modelled scenarios

The following aspects have been analysed with the study model:

1. Sensitivity of prices to parameter variations (LP approach)

- ❑ Approach of must-run implementation (incl. discrimination per technology/generator)
- ❑ Consequences of neglecting negative reserve capacity requirements
- ❑ Impact of storages / DSM on prices (different storage sizes)
- ❑ Impact of linearized intertemporal constraints (start-up costs, part-load efficiencies)

2. Sensitivity of prices to model approach and auction design

- ❑ LP vs. MILP implementation effects on plant dispatch and capacity reserve prices
- ❑ Impact of commitment period on reserve capacity prices

3. Ability of participants to anticipate auction outcomes

- ❑ Comparison of prices stemming from duals vs. ex-post calculation
- ❑ Impact of parameter variation on difference between dual vs. ex-post calculated prices

Modelled scenarios

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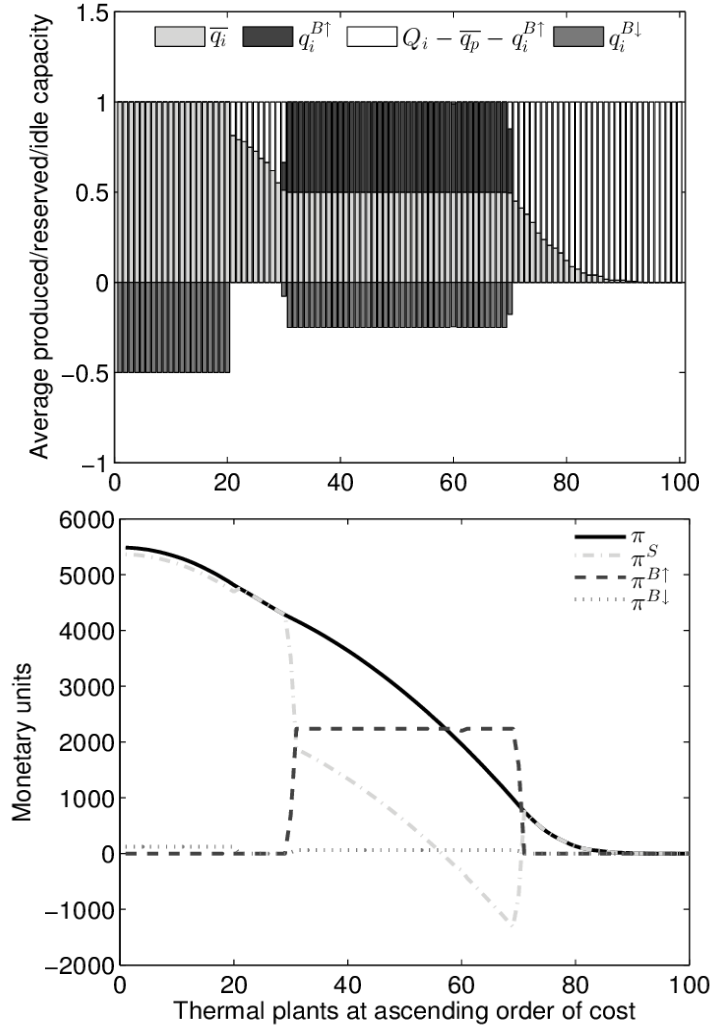
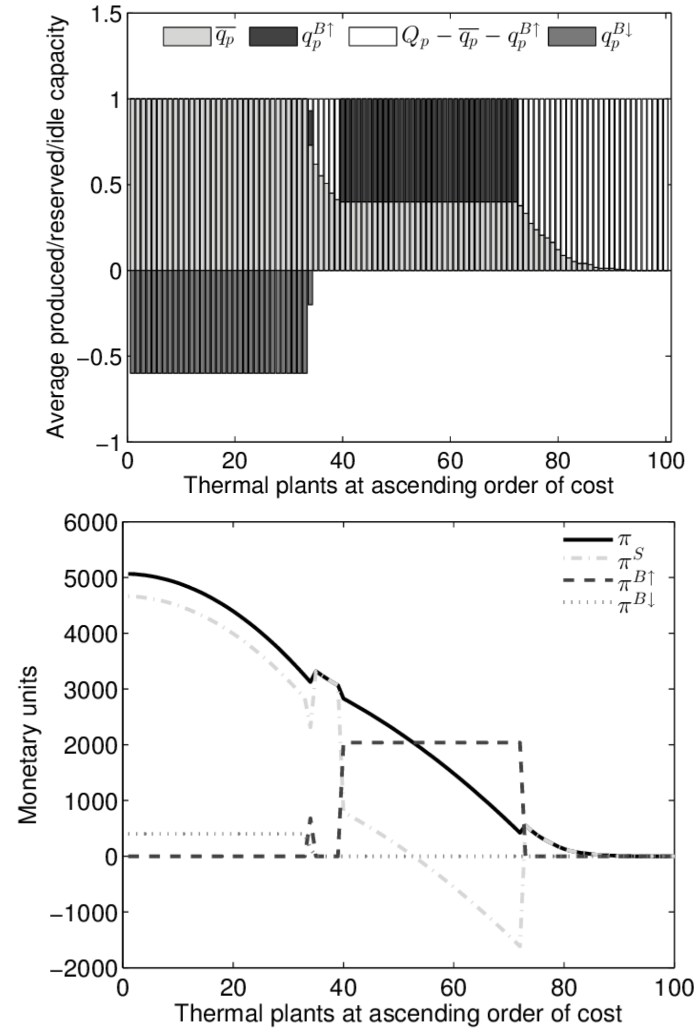
LP vs. MILP implementation

Non-convexities are essential for the dispatch and prices of <u>negative</u> of capacity reserves

LP

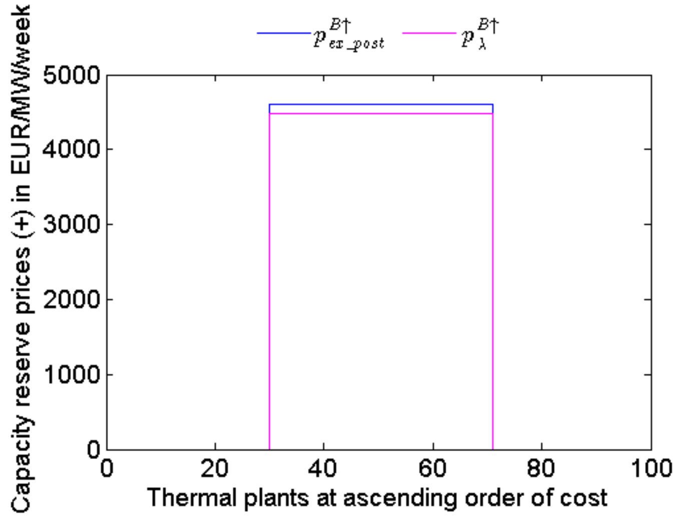


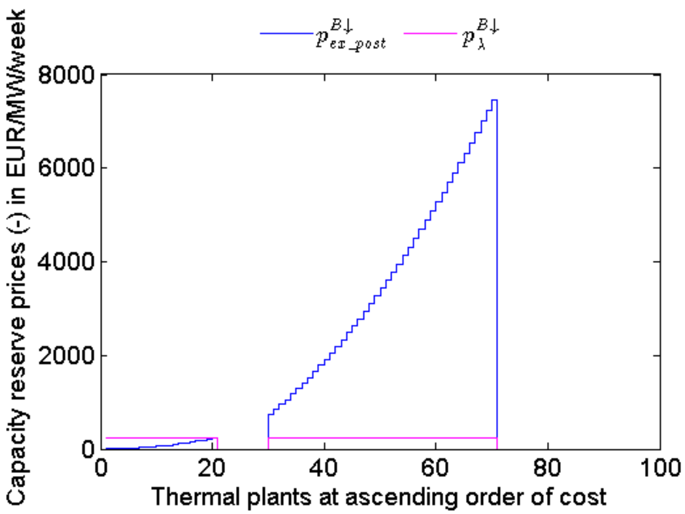
MILP



Ability of participants to anticipate auction outcome

Dual prices (marginal system costs) vs. ex-post calculation (incurred costs per generator)





	maximum difference				average difference			
D_Bp/Bn	pos		neg		pos		neg	
MW	EUR/MW	%	EUR/MW	%	EUR/MW	%	EUR/MW	%
5	0	0.00	0	0	0	0.00	0	0.00
10	1	0.03	2	100	1	0.03	1	94.86
15	18	0.49	36	100	18	0.49	32	88.02
20	116	2.59	232	100	116	2.59	205	88.24

	maximum difference				average difference			
pMin	pos		neg		pos		neg	
[1]	EUR/MW	%	EUR/MW	%	EUR/MW	%	EUR/MW	%
0.25	9	0.52	5	100	1	0.22	2	84.40
0.5	16	0.57	48	100	5	0.57	21	85.93
0.75	42	1.12	98	100	16	1.12	49	87.41
1	116	2.59	232	100	48	2.59	205	88.24

	maximum difference				average difference			
d_sMean	pos		neg		pos		neg	
[1]	EUR/MW	%	EUR/MW	%	EUR/MW	%	EUR/MW	%
40	476	13.95	963	100	146	10.74	528	91.35
50	116	2.59	232	100	48	2.59	125	88.24
60	32	0.59	64	100	13	0.59	34	88.24

	maximum difference				average difference			
comP	pos		neg		pos		neg	
[1]	EUR/MW	%	EUR/MW	%	EUR/MW	%	EUR/MW	%
1	116	2.59	232	100	48	2.59	125	88.24
2	68	2.99	136	100	26	2.80	68	89.12
24	22	12.42	25	100	3	3.76	5	88.77
168	29	127.92	42	100	4	47.41	4	97.70

Ability of participants to anticipate auction outcome

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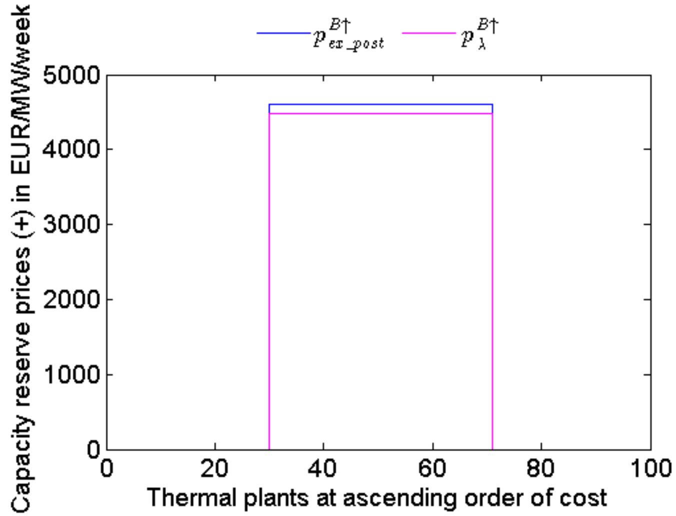

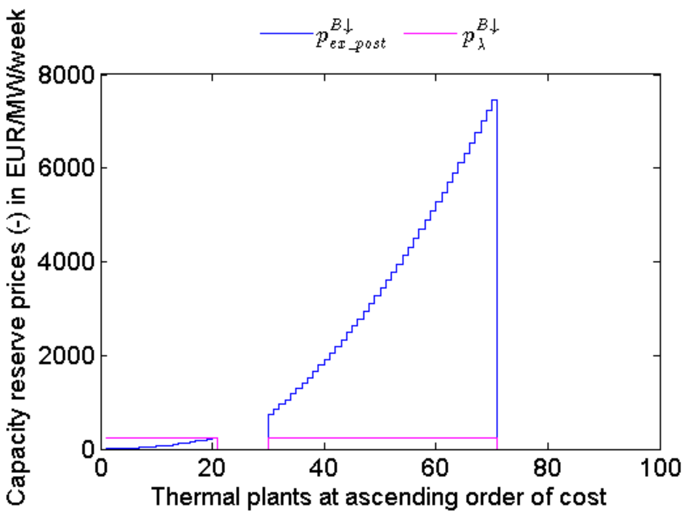

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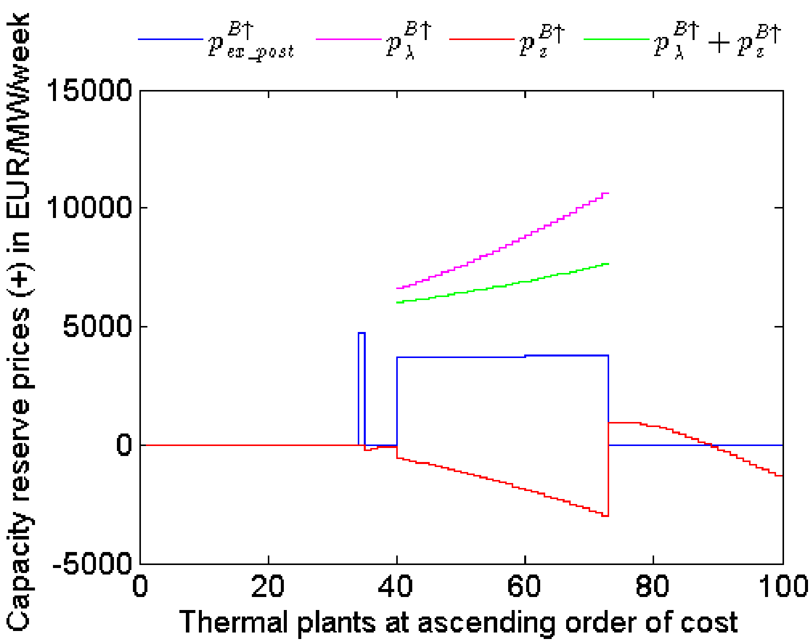
	maximum difference				average difference			
comP	pos		neg		pos		neg	
[1]	EUR/MW	%	EUR/MW	%	EUR/MW	%	EUR/MW	%
1	116	2.59	232	100	48	2.59	125	88.24
2	68	2.99	136	100	26	2.80	68	89.12
24	22	12.42	25	100	3	3.76	5	88.77
168	29	127.92	42	100	4	47.41	4	97.70

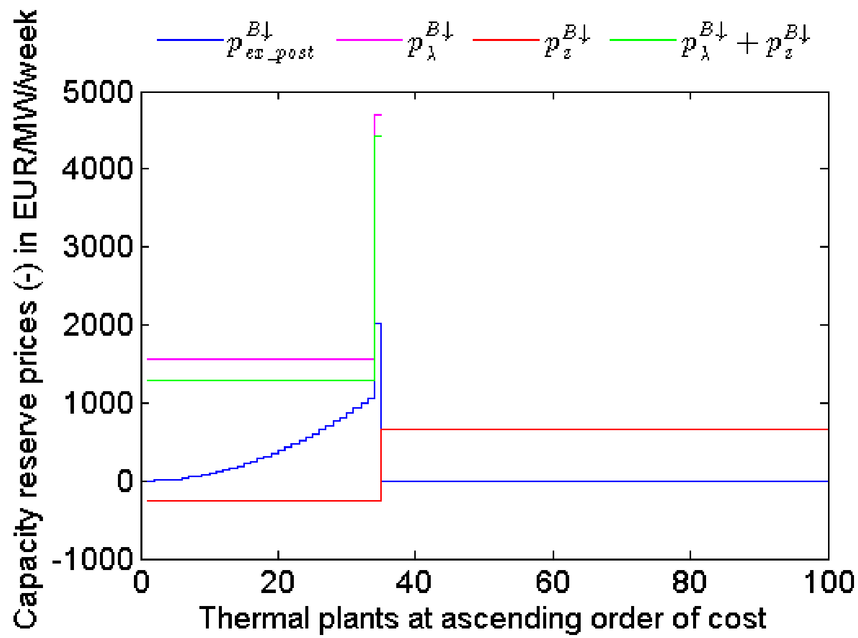
Ability of participants to anticipate auction outcome

In the MILP approach the derivation of market-clearing prices becomes tricky

- Due to non-convexities efficient prices withdrawn from the duals of system constraints are no longer valid if no additional capacity price is paid to all units.
- One option to derive prices from MIP's: Treat binaries like separate commodities (O'Neill 2005)
- Binary decisions variables on providing reserves or not are fixed. Resulting (positive) shadow variables have to be paid in additional to other costs.

$$z_i^{B\uparrow} = (z_i^{B\uparrow})^* \quad (p^{z\uparrow}), \quad \forall i$$
$$z_i^{B\downarrow} = (z_i^{B\downarrow})^* \quad (p^{z\downarrow}), \quad \forall i$$





Conclusions

- The modelling of capacity reserve prices in European's electricity balancing markets is not trivial and needs some further attention
- The use of "Co-Optimization" or "Integrated modelling" approaches are linked to strong assumptions
- It is crucial whether dual variables (system marginal costs), or if price-taking ex-post calculations (or price forward curves) are used to derive reserve price bids
- The applied methodology (linear vs. mixed-integer) has a considerable influence on what type of generators provide (negative) reserves and corresponding prices
  - However, both approaches enormously differ in computation time
- The use of shadow variables of system demand constraints in MIP problem formulations as proxies for prices is not sufficient to derive efficient equilibrium prices
  - Problems remain if positive capacity payments derived from duals of binary fixing equations have to be paid to generators for not providing reserves