Modeling perspectives on local flexibility markets

CEEM CONFERENCE on *The electricity market design: Key issues in the light of the ongoing challenges and priorities for future research*

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Background

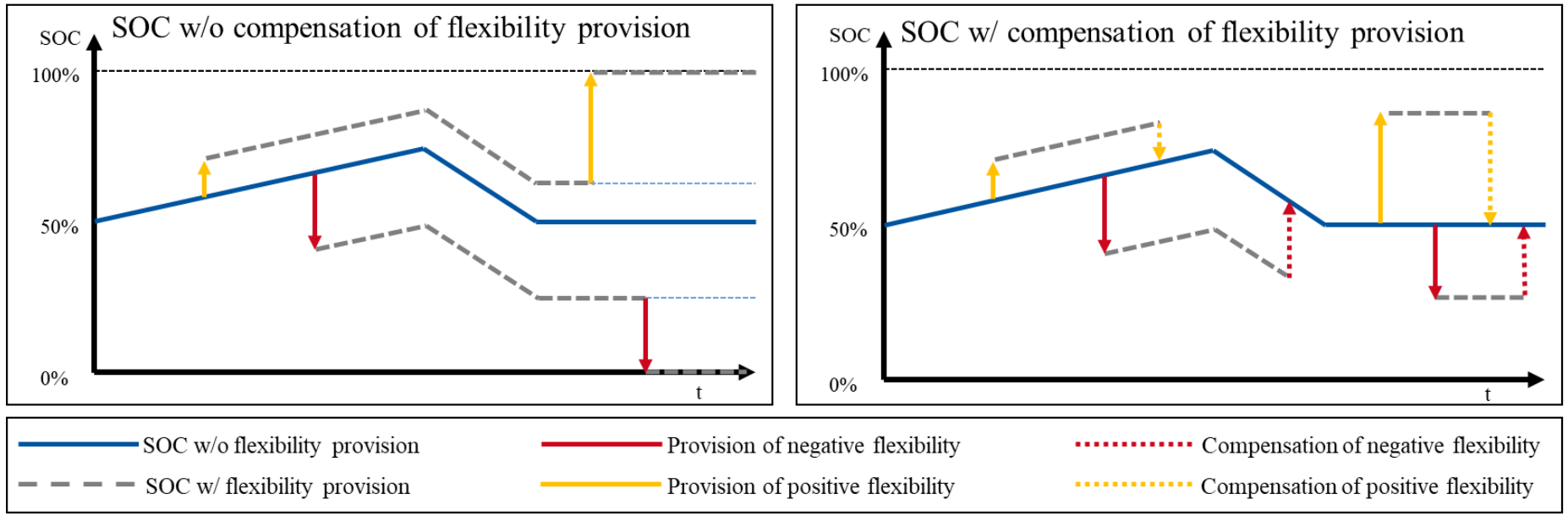
- Increasing congestion management:
  - Grid congestions on distribution and transmission grid level
  - Rising Redispatch and feed-in management costs
- Decentralization of flexibility:
  - Load-based flexibility (Heat pumps, electric vehicles,...) not integrated into congestion management
  - No marginal cost information available for most load-based flexibility
    → integration into cost-based congestion management not feasible
- Integration of load-based flexibility into congestion management with local flexibility markets (LFMs)
- However: General problem of inc-dec-gaming in short-term LFMs

➢ Quantification of problem through modeling and simulations

Modeling of load-based flexibility participation in LFMs (1/2)

How do DER operators optimize their market schedules?

- Load-based flexibility (Electric Vehicles, Heat Pumps) is mostly time-shifting
- Characteristics of storage systems: Adjustment of flexibility schedules in later points of time necessary
- Flexibility potential of load based-flexibility highly complex and limited to selected time steps
- Compensation of flexibility provision through intraday-market or in LFMs (with time-coupled bids)



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Modeling of load-based flexibility participation in LFMs (2/2)

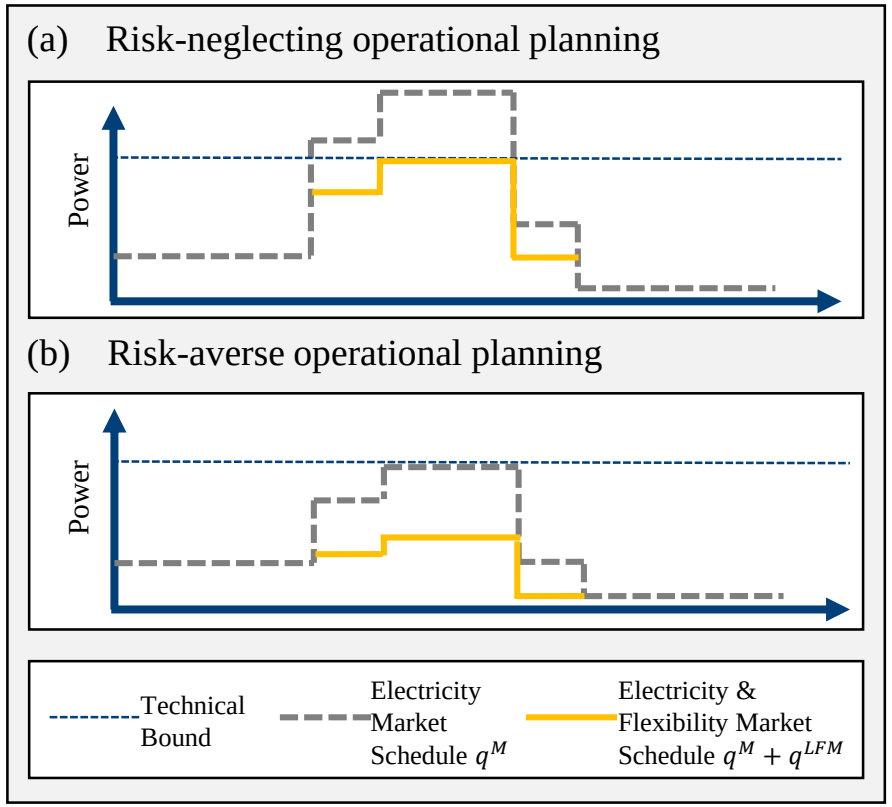
How do DER operators optimize their market schedules?

- Demand profile of electric vehicles and power-to-heat time-dependent
- Load coverage highest priority for prosumers
- Additional anti-inc-dec gaming measures such as stochastic non-activation of flexibility bids (cf. ENKO platform www.enko.energy)

➢ Higher risk-averseness for load flexibility assumed

- Definition of risk-averseness: a non-activation of LFM bids does not lead to deviations from pre-defined electricity market schedules

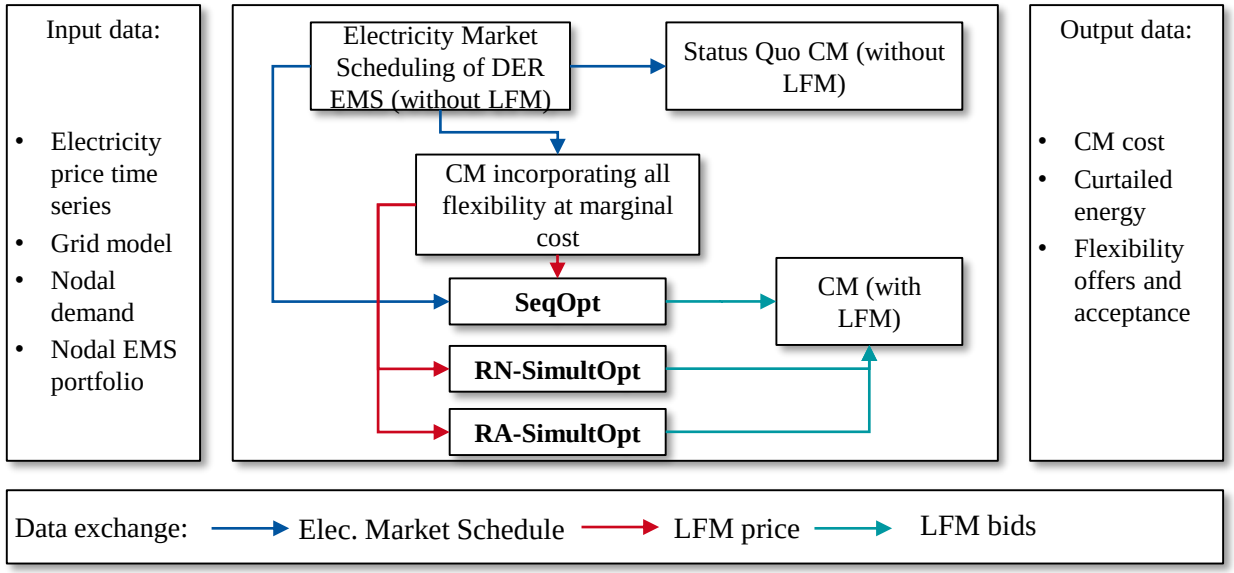
➢ Modeling with different activation scenarios of flexibility



Framework for assessment of LFM participation

Comparison of different planning modes

- Operational planning with Energy management systems (EMS) for different technology portfolios
- Three different EMS modes:
  1. SeqOpt: sequential optimization in different markets (first determine electricity market schedule, then offer remaining flexibility)
  2. RN-SimultOpt: Risk-neutral anticipative operational planning in LFMs and electricity markets (Full inc-dec-potential)
  3. RA-SimultOpt: Risk-averse anticipative operational planning in LFMs and electricity markets (no deviation from electricity market schedule by non-activation of bids)
- Comparison of modes with respect to impact on congestion management (CM)



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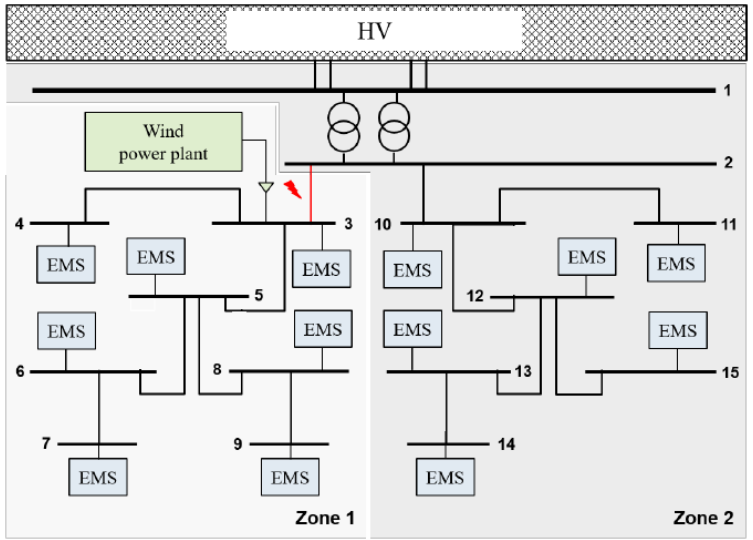
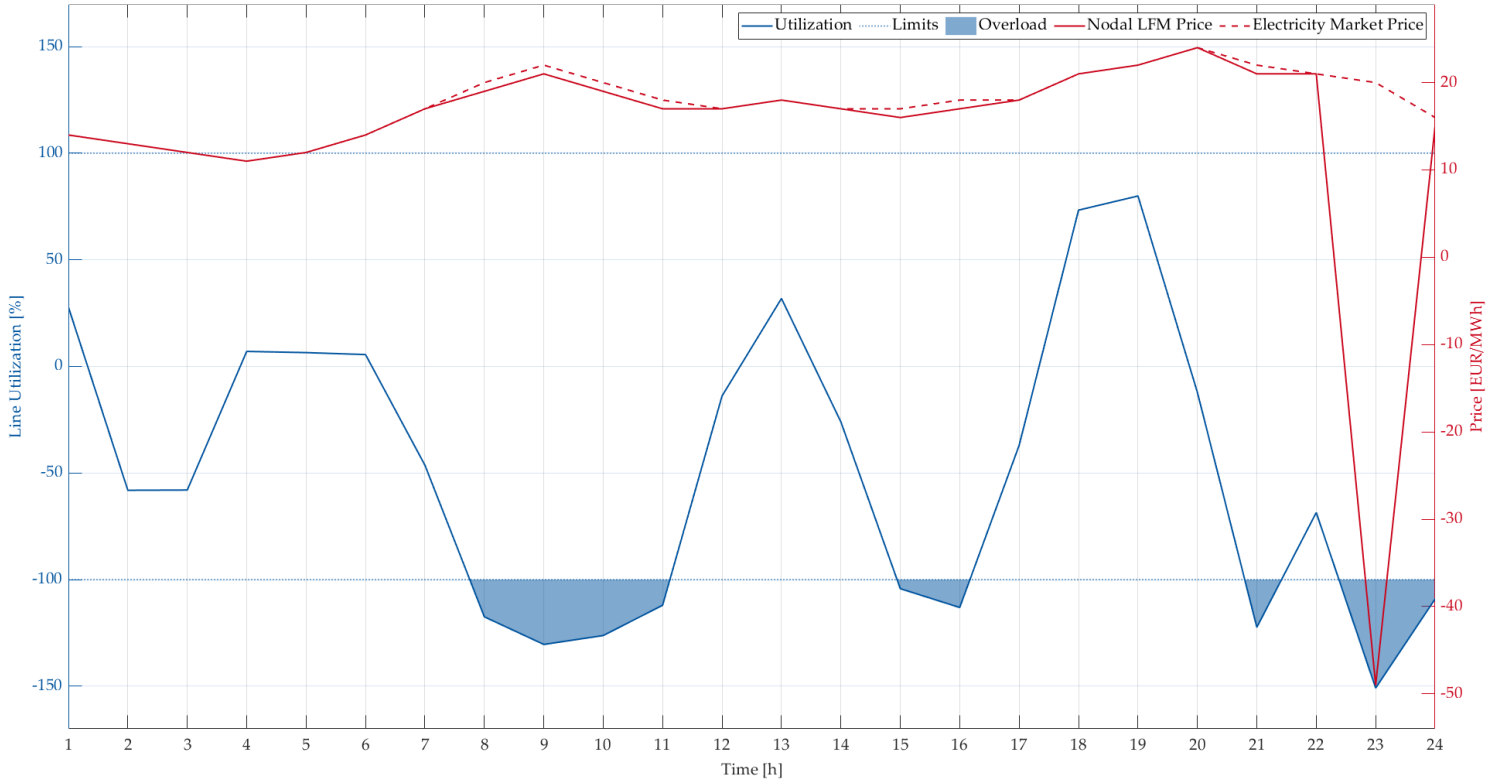
Case Study

- Distribution grid case study with overloaded line by wind power plant park
- Periodically overloaded line
- Curtailment costs of 50 EUR/MWh
- LFM price close to electricity price (high competition setting)





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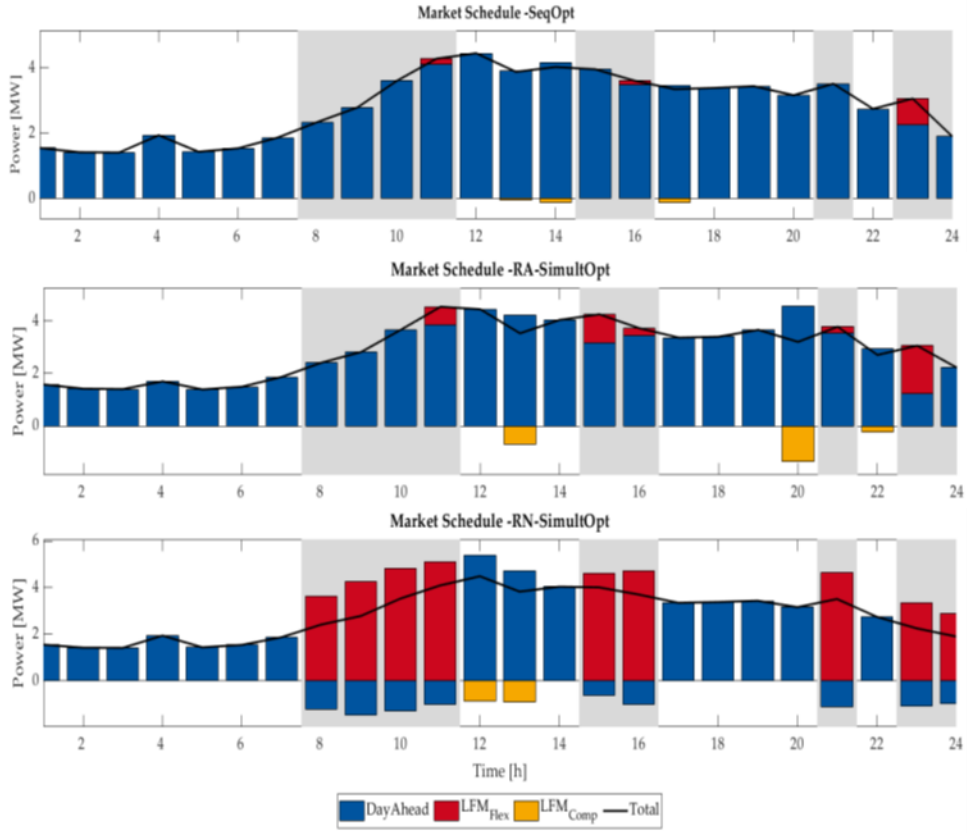
Results

- Comparison of market schedules for EMS in zone 1
- Limited remaining flexibility after electricity market optimization when LFM prices are not anticipated
- High difference in market schedules when comparing risk-averse and risk-neutral bidding in LFMs
- Even with anticipatory bidding (RA-SimultOpt) CM costs decrease due to limited gaming potential

➢ High impact of modelling assumptions on LFM assessment

CM Case	Status Quo	SeqOpt	RA-SimultOpt	RN-SimultOpt
CM costs [EUR]	878.96	813.69	870.71	1460.8
Total Overload [MWh]	12.55	12.55	19.71	99.27
Curtailment volume [MWh]	12.55	9.06	6.70	11.78
Offered Flexibility [MWh] (% activation)	-	3.49 (100%)	13.4 (95%)	87.49 (100%)
Offered Compensation [MWh] (% activation)	-	0.93 (100%)	7.76 (92%)	6.74 (100%)



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Discussion and Conclusion

- Inc-dec-gaming in LFMs a well-known problem
- Load-based flexibility mainly focused on load coverage
- Assumption of risk-averseness for load-based flexibility
- Insight into real potential through modeling
- Assumptions have high impact into behavior
- Case study shows example where even with inc-dec-gaming LFMs bring a net benefit to congestion management (even with perfect foresight)

➢ Large-scale assessment of LFMs needed for different types of distribution grids and levels of competition

Thank you for your attention!

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