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OPTIMIZATION OF THE BIDDING STRATEGY OF A VIRTUAL POWER PLANT BY PARTICIPATING IN SHORT-TERM, BALANCING- AND REDISPATCH MARKETS

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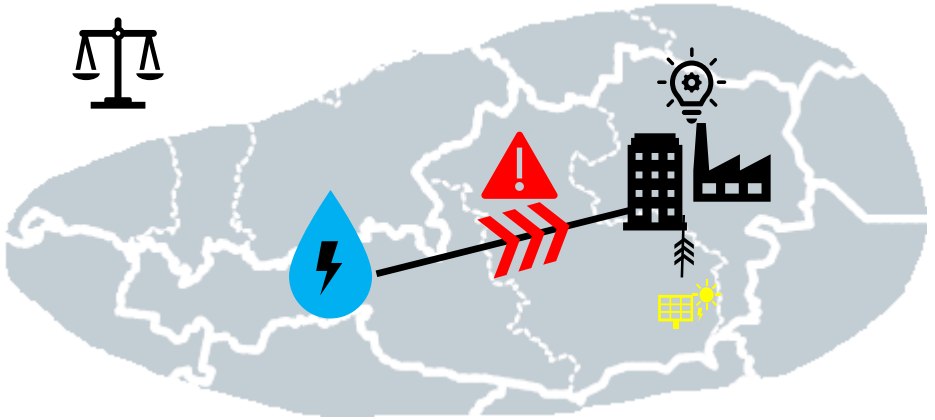
Problem



- Redispatch: Solving grid congestions by increasing production in one plant and decreasing production in another plant after clearing of day-ahead-market
- Congestion management costs increasing over time
- Size of production units is decreasing
- Possibility of redispatch provision by RES?

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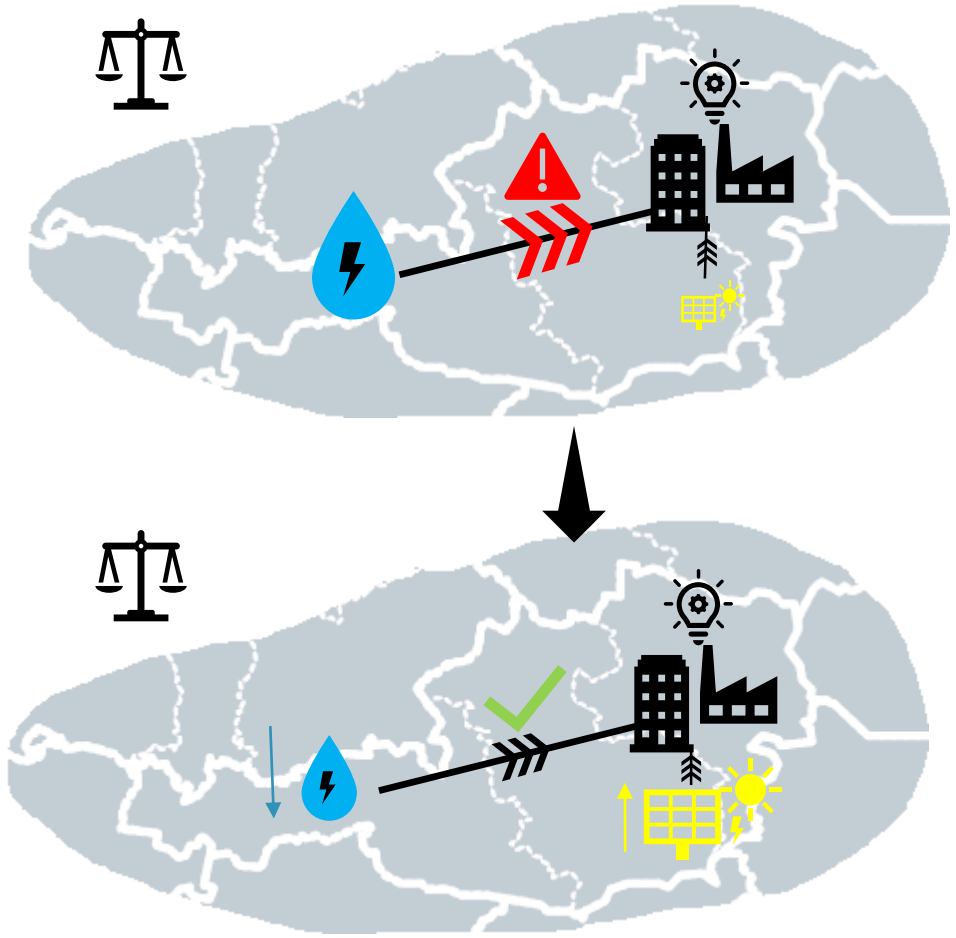

Project and goals

- Project REgions: 1.10.2019 - 30.09.2022
- Using photovoltaic production for congestion management
- Main topics within this subtask:
  - Suggestion for Redispatch “market” design
  - Redispatch call probabilities for different Austrian Zones
  - Optimization Algorithm for bidding of a VPP
  - Investigate interference of Redispatch and Balancing market

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Assumptions for the bidding algorithm

- Participation at **Day-Ahead** and I**ntraday** spot markets, balancing and redispatch markets

Balancing market (Secondary control)

- Remuneration for capacity reservation (GCT D-1)
- Remuneration for energy (GCT balancing energy market: one hour before product delivery)
- Pay-as-bid (call based on Merit-Order)
- Call probabilities are independent of location of the plant

Suggestion: Redispatch market

- No capacity reservation
- Remuneration for energy (GCT: one hour before product delivery)
- Comparison of different pricing schemes either correlated to day-ahead-spot-price or nodal pricing
- Directly linked to DA-market (to avoid gambling)
- Call probabilities are dependent of location of the plant

Calculation of call probabilities

1. Net generation and consumption for Austria for each grid node
2. Power flow analysis to calculate congestions
3. Iterative redispatch algorithm to solve congestions
4. Redispatch amounts aggregated to three different zones for each timestep
5. Probabilities of redispatch call for each hour during the day can be calculated from yearly data

Three zones of Austria:

- **ZoneEast**: Vienna, Lower Austria and Burgenland
- **ZoneMid**: Upper Austria, East-Carinthia, and Styria
- **ZoneWest:** Salzburg, West-Carinthia, Tyrol and Vorarlberg

Bidding strategy: Optimization problem

- LP problem
- Cost minimization function:
  - $costs = \sum_t costs_{DA}(t) - profits_{FRR}(t) - profits_{redispatch}(t) + costs_{ID}(t)$
  - For redispatch and balancing, the profits in this equation are calculated with the above mentioned call probabilities
- To guarantee all possible call situations:
  - $P_{VPP}('prob', t) = da(t) - \sum_{mol}(frr_{neg}(mol,t) * frr_{neg}^{prob}(mol,t) - frr_{pos}(mol,t) * frr_{pos}^{prob}(mol,t)) - redispatch_{neg}(t) * redispatch_{neg}^{prob}(t) + redispatch_{pos}(t) * redispatch_{pos}^{prob}(t)$
  - $P_{VPP}('pos', t) = da(t) + redispatch_{pos}(t) + \sum_{mol} frr_{pos}(mol,t)$
  - $P_{VPP}('neg', t) = da(t) - redispatch_{neg}(t) - \sum_{mol} frr_{neg}(mol,t)$
- Perfect forecasts for prices
- PV forecast is changing from D-1 to D
- Intraday costs for compensation of forecast errors

$costs_{DA}(t)$… costs from the day-ahead market
$costs_{ID}(t)$ …costs from the intraday market
$profits_{FRR}(t)$…profits from the balancing market
$profits_{redispatch}(t)$…profits from the redispatch market
$P_{VPP}(x,t)$ … Power of the VPP grid connection point [kW]
x … probable, positive or negative case of activations
$da(t)$… Power sold at the DA market [kW]
dir… direction [‚positive‘,‘negative‘]
mol…merit-order-list position
$frr_{dir}(mol,t)$… Balancing bid [kW]
$redispatch_{dir}(t)$… redispatch bid [kW]
$frr_{dir}^{prob}(mol,t)$…balancing call probability
$redispatch_{neg}^{prob}(t)$…redispatch call probability

Results I

- **Reference:** Injection into the grid, remunerated by day-ahead-prices
- **aFRR:** Possibility to participate at spot-markets (DA + ID) and aFRR market
- **Redispatch:** Possibility to participate at spot-markets (DA + ID) and redispatch market (with nodal pricing*)
- **aFRR + Redispatch:** Possibility to participate at participate at spot-markets (DA + ID) and aFRR + redispatch

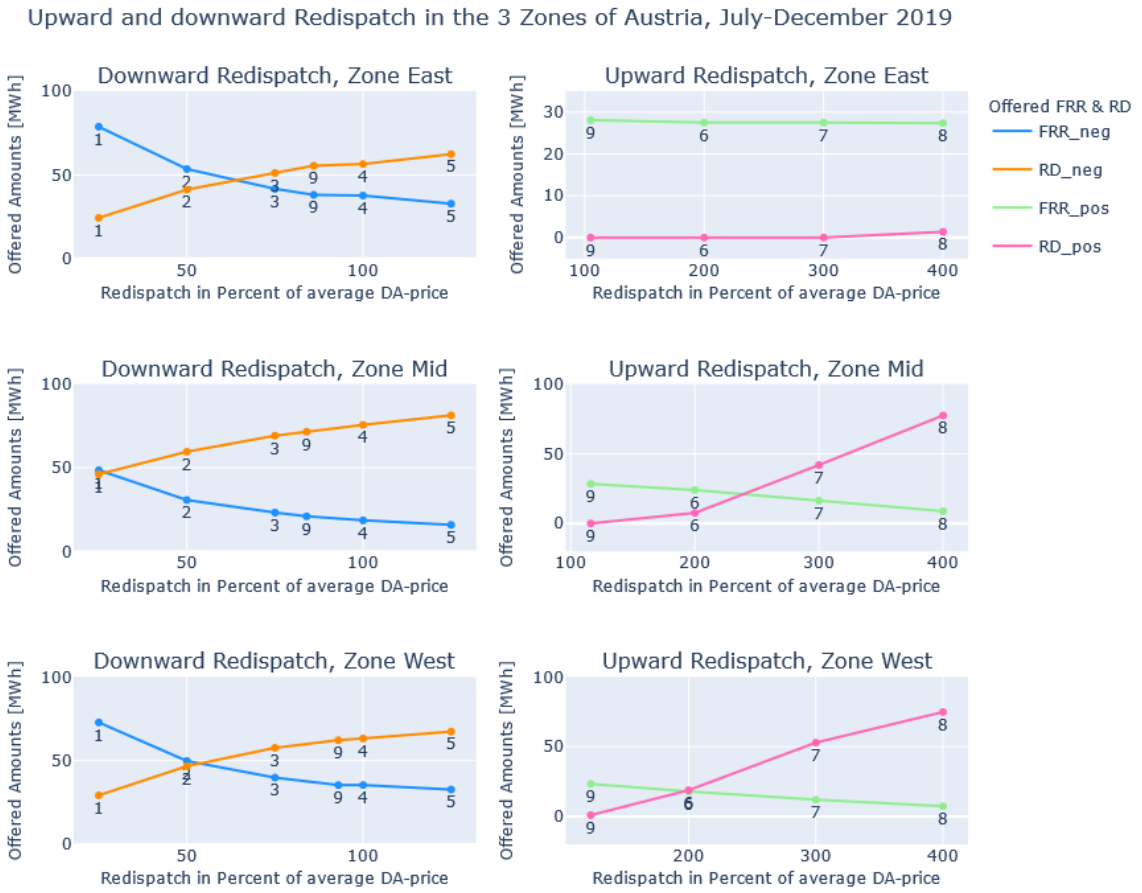
→ Possibility of participation at all markets gives the highest results

Total revenues for Zone West, July- December 2019

Results II

Scenario number	Remuneration upward redispatch	Remuneration downward redispatch
1	100 % of day-ahead-price	25 % of average day-ahead-price
2	100 % of day-ahead-price	50 % of average day-ahead-price
3	100 % of day-ahead-price	75 % of average day-ahead-price
4	100 % of day-ahead-price	100 % of average day-ahead-price
5	100 % of day-ahead-price	125 % of average day-ahead-price
6	200 % of day-ahead-price	100 % of average day-ahead-price
7	300 % of day-ahead-price	100 % of average day-ahead-price
8	400 % of day-ahead-price	100 % of average day-ahead-price
9	Nodal prices*	Nodal prices*

*Nodal prices: are depending on average amounts of called redispatch (prices are higher the more redispatch is called, function between cheapest called plant (solar) and most expensive called plant (gas))



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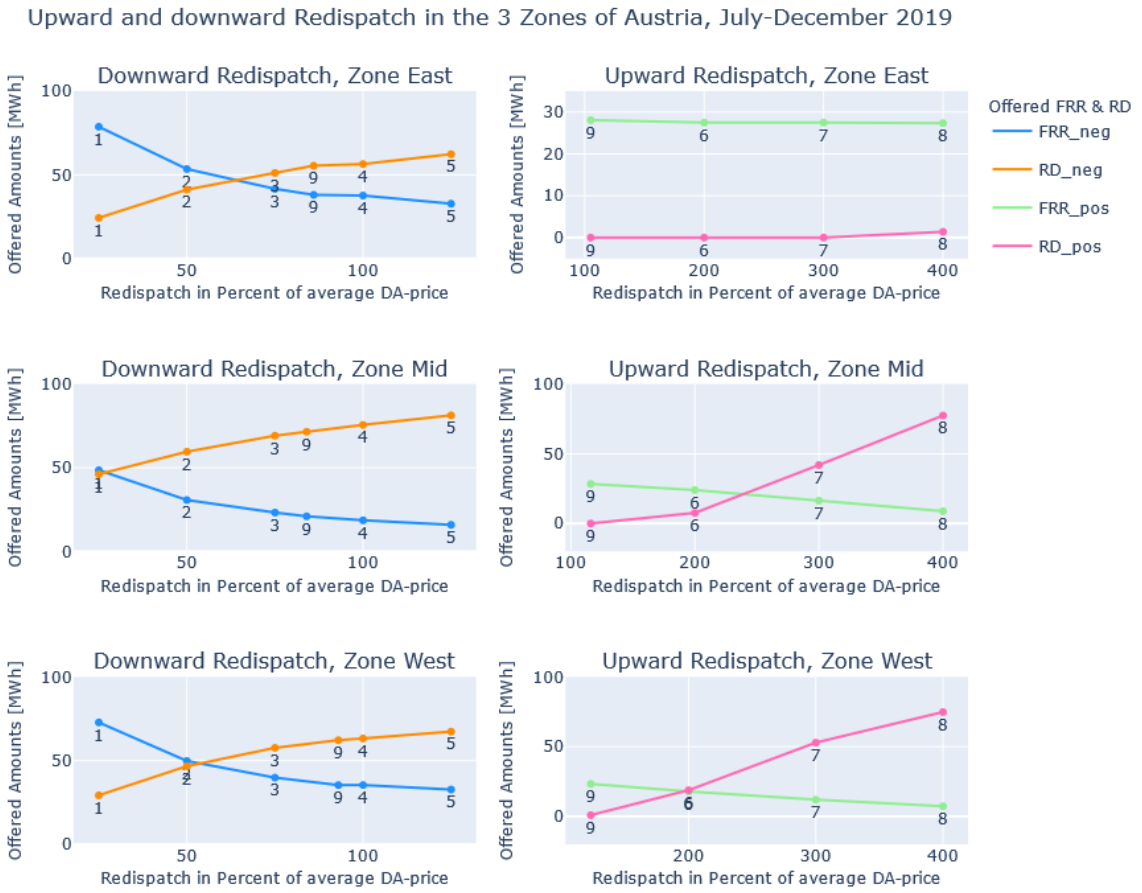

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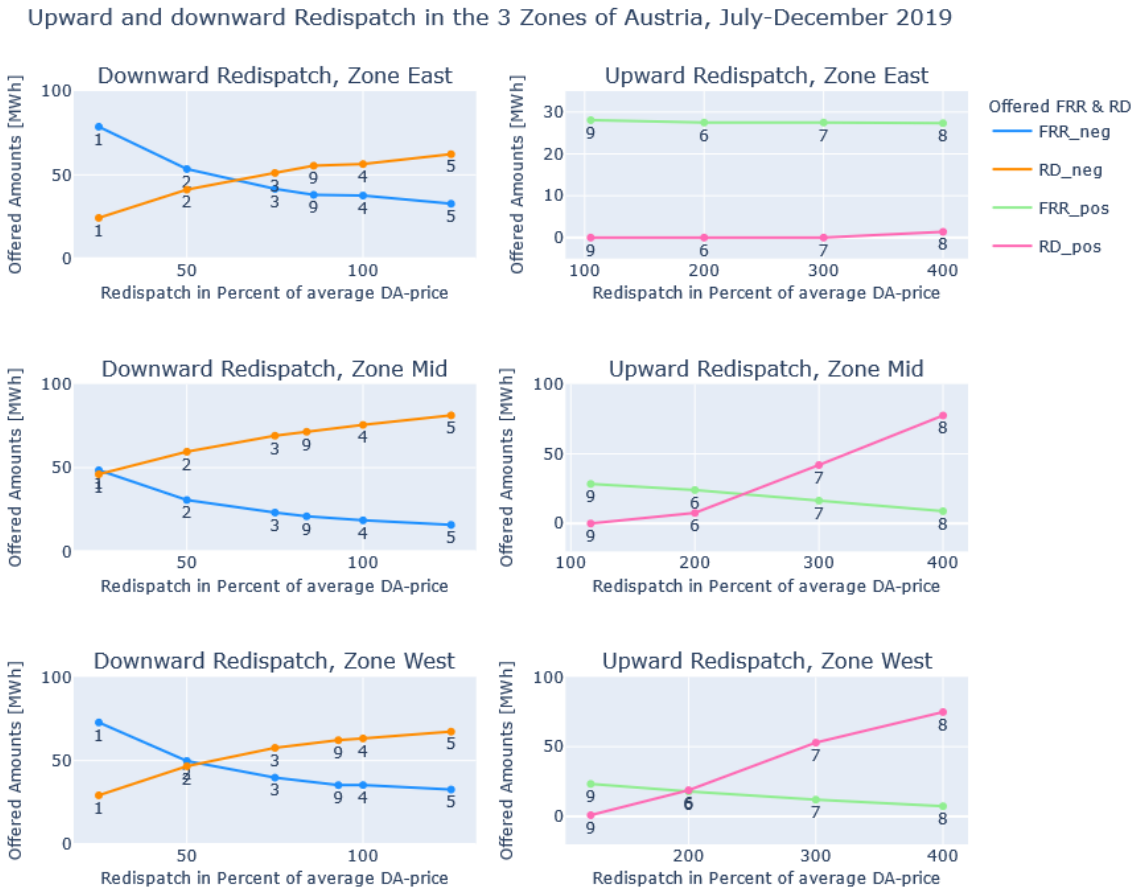

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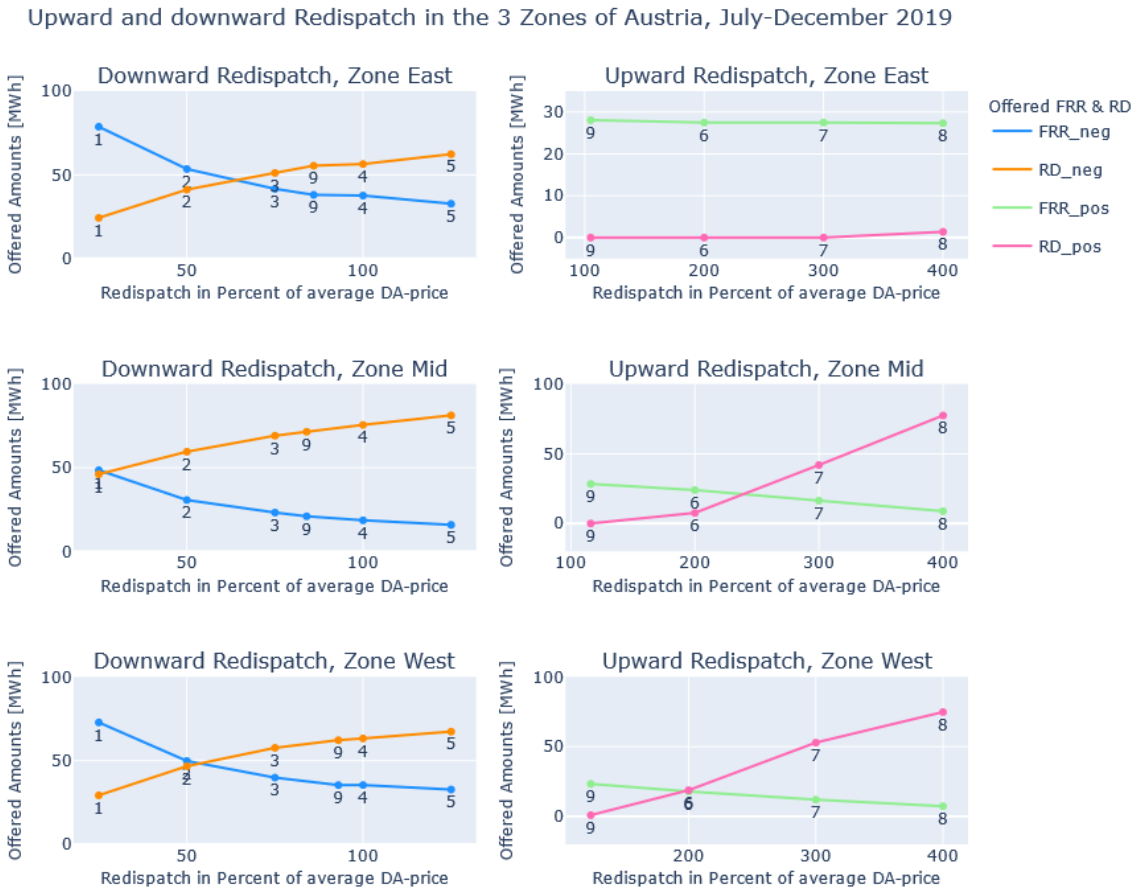

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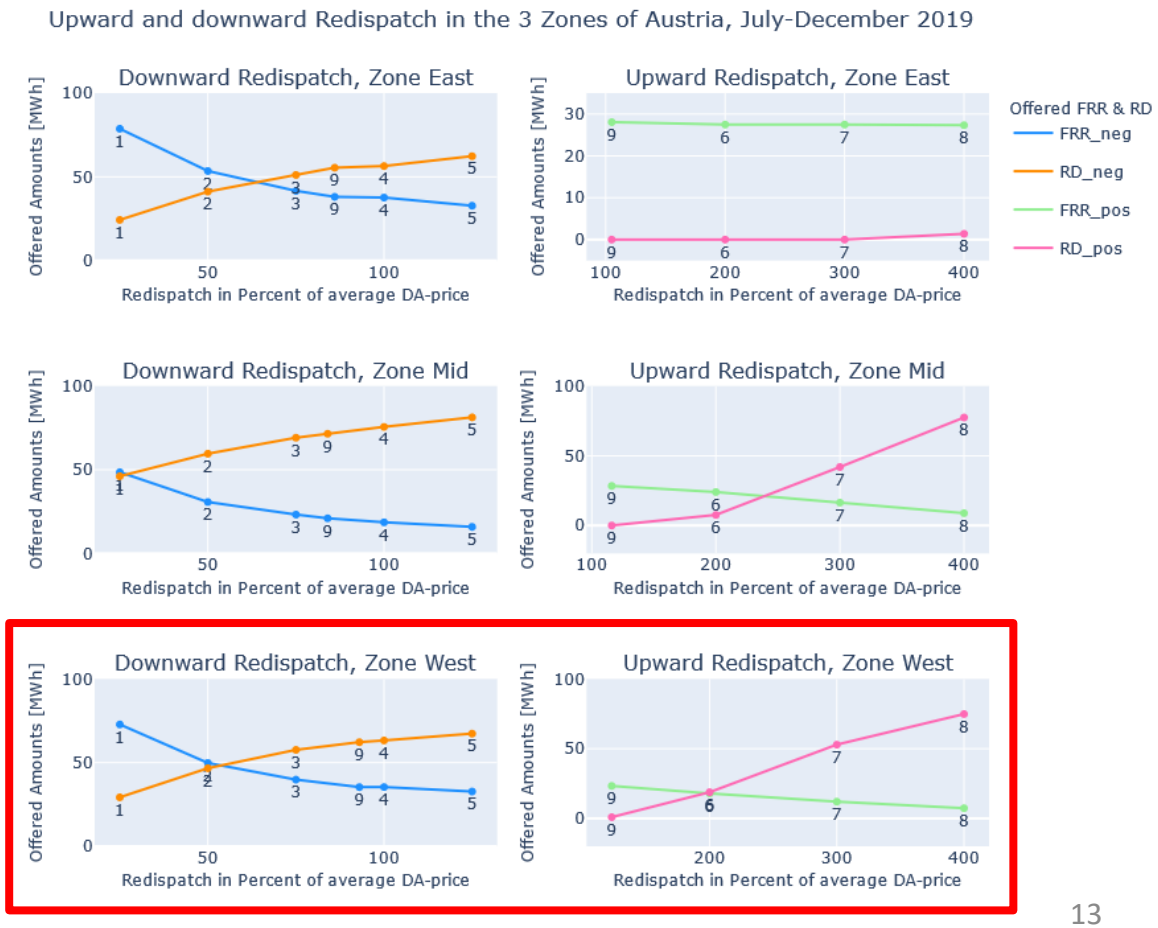

Results II

Total bid amounts of redispatch and balancing in upward and downward direction

Conclusions and outlook

- Bid amounts:
  - Highly dependent on the selected remuneration scheme
  - Dependent on the node or zone of the grid, where VPP is located
- In zones with high redispatch demand, low prices are already a good incentive (25% of DA-price in Zone mid for negative redispatch)
- Bid amounts at balancing and redispatch market correlate inversely proportional
- Negative effects on the grid can occur, because in areas where redispatch in one direction is not required, balancing in the not desired/required (other) direction will be bid and activated
- Next steps: include electrical storage into the model

THANK YOU FOR YOUR ATTENTION

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