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Evangelos Panos, Martin Densing

Energy Economics Group, Paul Scherrer Institute, Switzerland

The future development of the electricity prices in view of the implementation of the Paris Agreements in 2030: will the current trends prevail or a reversal is ahead?

The 37th Edition of International Energy Workshop (IEW), Gothenburg, 19-21 June 2018

The EU “Clean Energy for all Europeans Package”

Aims at enabling EU to deliver on its Paris Agreements commitments:

GHG in 2030 40% down from 1990

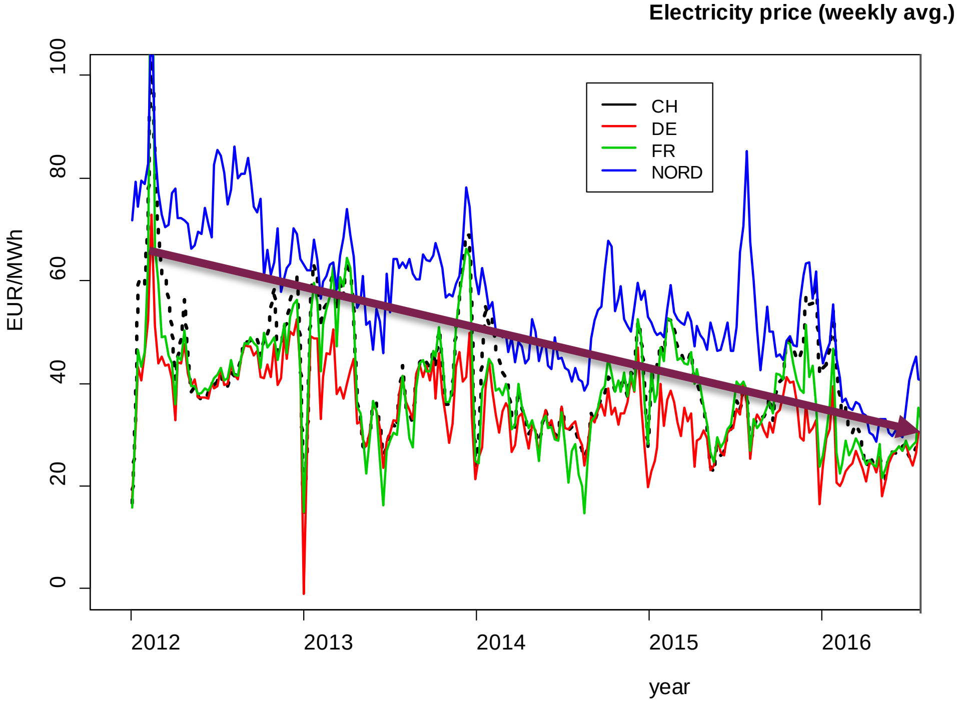
Renewables as % of gross final energy demand: 27% in 2030

Primary energy: reduced in 2030 by 27% (or 30%) relative to the EU Baseline scenario of 2007

Main research question

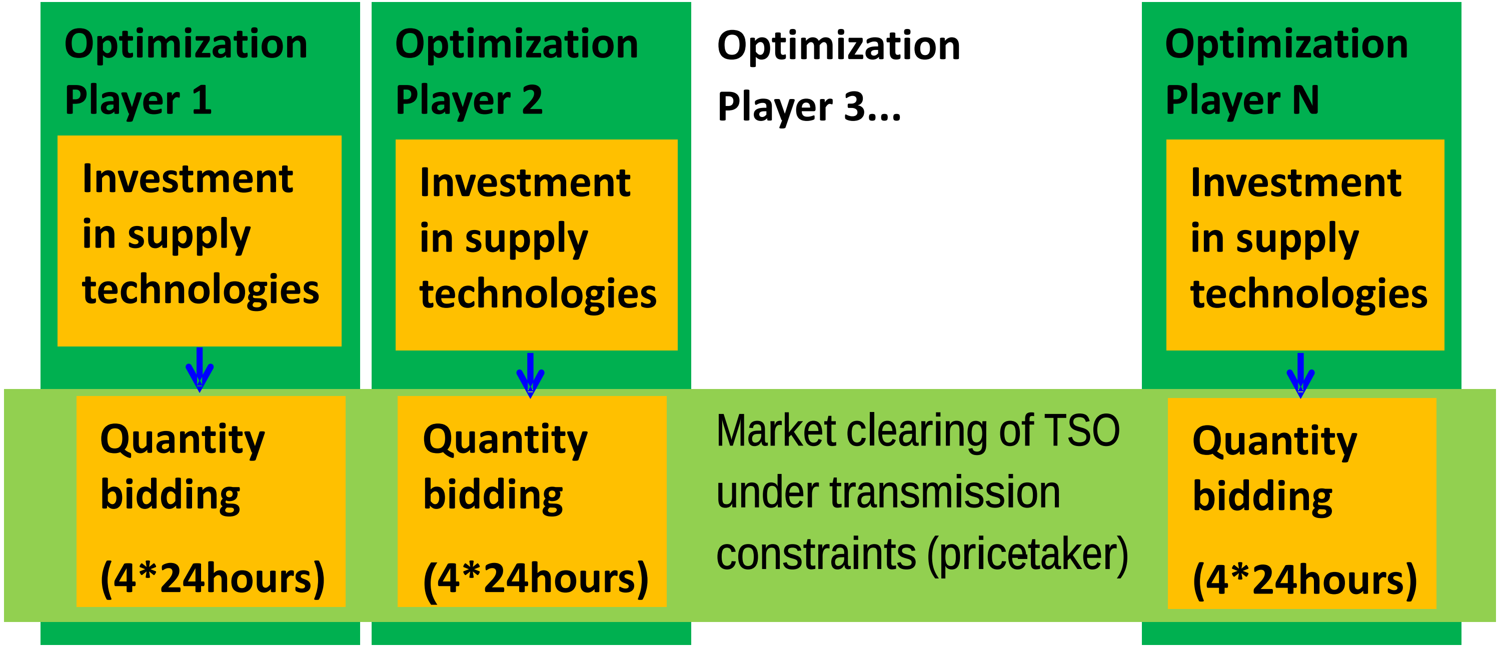
Can electricity prices rise again?

Especially under the implementation of the “Clean Energy for all Europeans Package”



Cross-Border Electricity Market (BEM) model

Classical Nash-Cournot game to understand price formation & investments

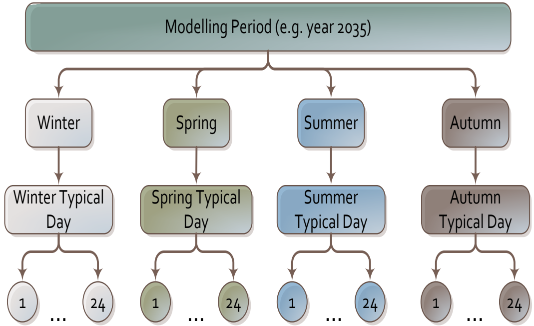


- The model can also run in different modes: (i) Deterministic or Stochastic; (ii) Social welfare maximization

Main features of the BEM model

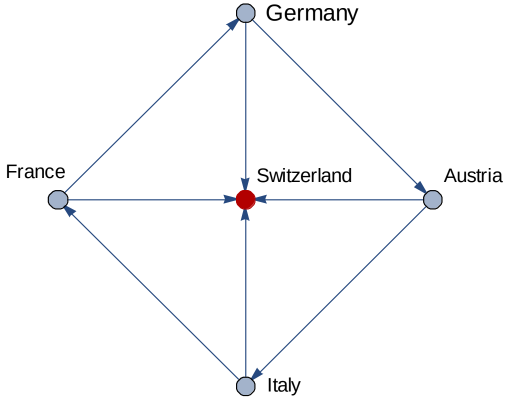
01 Long term horizon & high intra-annual resolution

Each modelling period is divided into 96 typical operating hours, corresponding to 1 typical day per season; the framework is flexible allowing for defining more types of days within a season



02 Grid Transmission constraints between the players

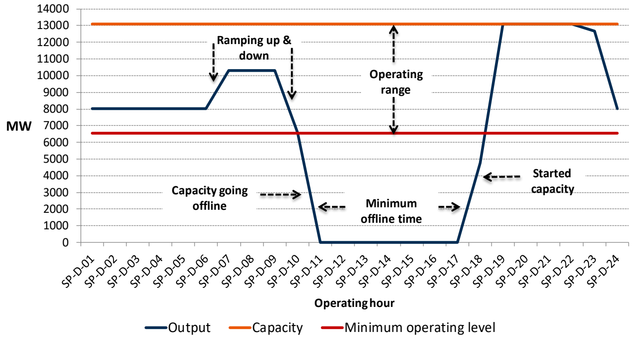
A DC power flow approximation is modelled for representing the grid transmission constraints between the nodes/players; in each node power plants can be located belonging to player(s); **in the current setup of the model the players are Switzerland and its neighbouring countries**



Main features of the BEM model

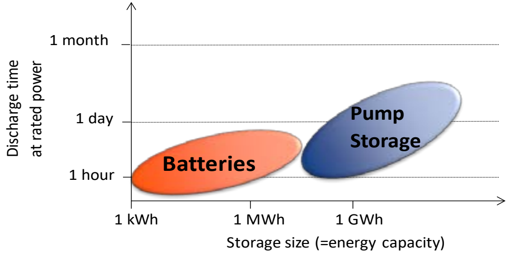
03 Operating constraints for power plants

A linearized approximation of the unit commitment problem is formulated based on clustering of similar units to represent: part load efficiency losses, ramping constraints, minimum operating levels, online/offline times, start-up costs, etc.



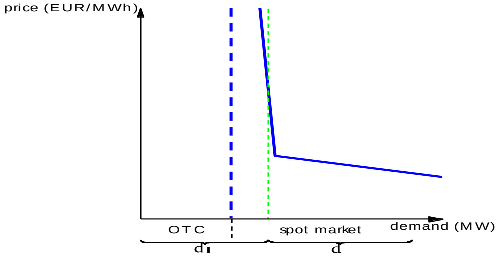
04 Representation of RES variability & storage

Based on a historical sample of solar and wind generation the model ensures that there is enough storage and dispatchable capacity to accommodate residual load curve variations and curtailment.



05 Elastic and inelastic electricity markets

The model can represent both elastic (i.e. traded) electricity demand and inelastic (i.e. over the counter - OTC) demand; the OTC demand is considered to be perfect competitive to avoid an exponential demand function representing both markets



Calibration within the BEM model

The model has an estimation mode for the conjecture of a player regarding the aggregated reaction of its rivals, which is used to reproduce the historical prices

In a quantity offering setting q_i, each producer i tries to maximise its own profit (sales at price $p(q_{tot})$ minus production costs $C_i(q_i)$):

$$\max_{q_i \in R^+} p(q_{tot}) q_i - C_i(q_i)$$

The first order condition of the above problem is:

$$p(q_{tot}) - \frac{\partial q_{tot}}{\partial q_i} \cdot \frac{\partial p(q_{tot})}{\partial q_{tot}} \cdot q_i - C_i'(q_i) \leq 0 \perp q_i \geq 0$$

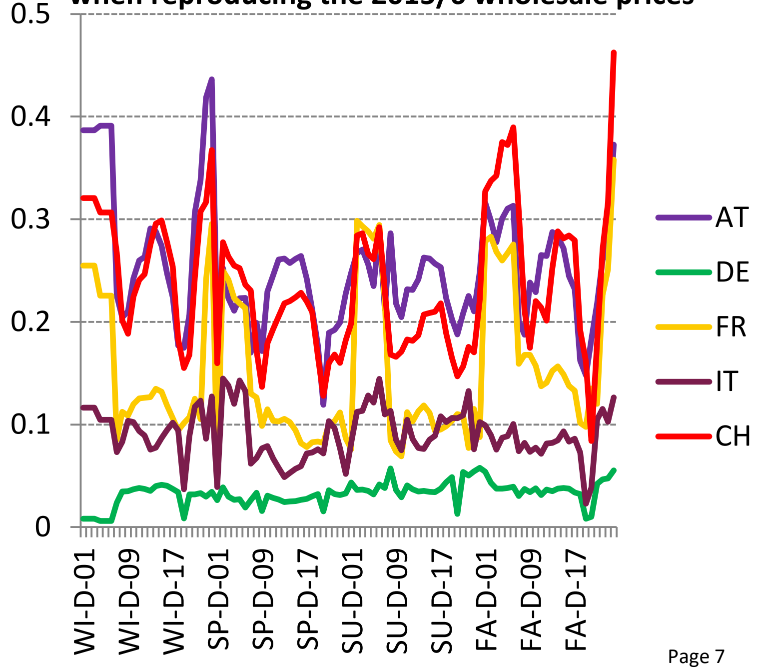
$\theta_i \coloneqq \frac{\partial q_{tot}}{\partial q_i}$ conjecture of producer i

$\theta_i = 0$ perfect competition conjecture

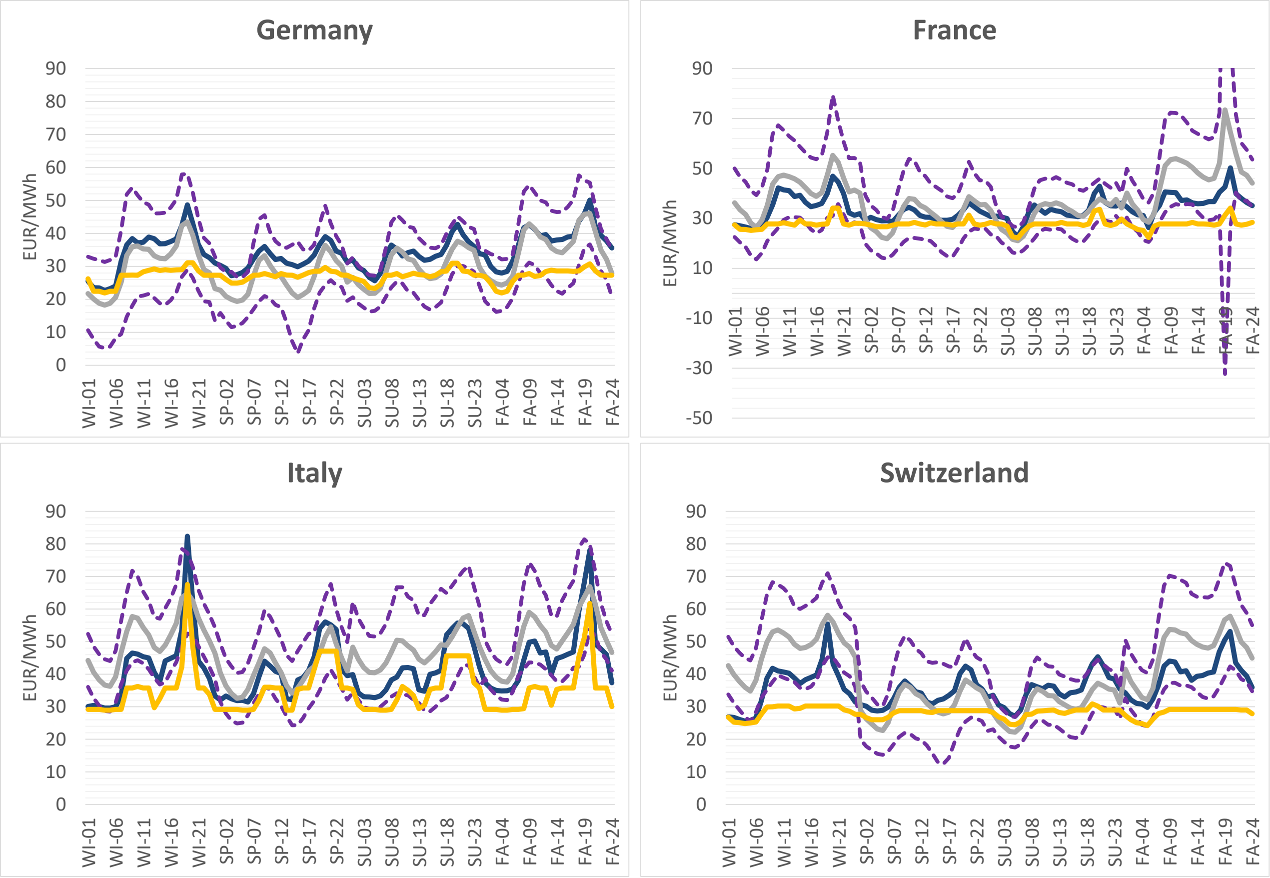
$\theta_i = 1$ Nash conjecture

$\theta_i \in (0, 1)$ Intermediate imperfect competition conjecture

Estimated deviation of θ_i from the model's cost-curve when reproducing the 2015/6 wholesale prices



Calibration of the BEM model to 2015/6 prices



Average wholesale day-ahead price 2015/6

BEM model price 2015/2016 (Game-theoretic formulation)

BEM model price 2015/2016 (Social Welfare formulation)

1 std. dev. of the historical prices 2015/2016

Technical constraints are important, but how to model the part of the price which is not explained by the marginal cost → Nash-Cournot with calibrated θ_i

Definition of the scenarios

Two core scenarios for year 2030 are assessed:

	Base	Low Carbon
Description	Reference scenario, based on EU TRENDS 2016 Scenario of EC	Climate scenario -40% reduction of CO_2 in 2030 from 1990 levels ("Clean Energy for All Europeans")
Fuel prices in 2030 (1)	Gas: 28 €/MWh, Coal: 12 €/MWh (in EUR_{2015})	
CO_2 price in 2030	30 €/tCO_2	80 €/tCO_2 (2)

[1] IEA World Energy Outlook 2017, New Policies Scenario

[2] IEA World Energy Outlook 2017, Sustainable Scenario

Today's gas price (2015/6) 14 €/MWh, today's coal price 9 €/MWh

Three additional variants:

a) Enabling investment in batteries (transmission level) for additional flexibility
b) Maintaining the fuel costs and CO_2 prices of 2015/6 ("TodayCost")
c) Increasing the cross-border capacities by 1 GW (ENTSO-E regional inv. plan)

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Scenarios: Marginal electricity production costs

Marginal costs (EUR/MWh), based on the fuel and CO_2 prices

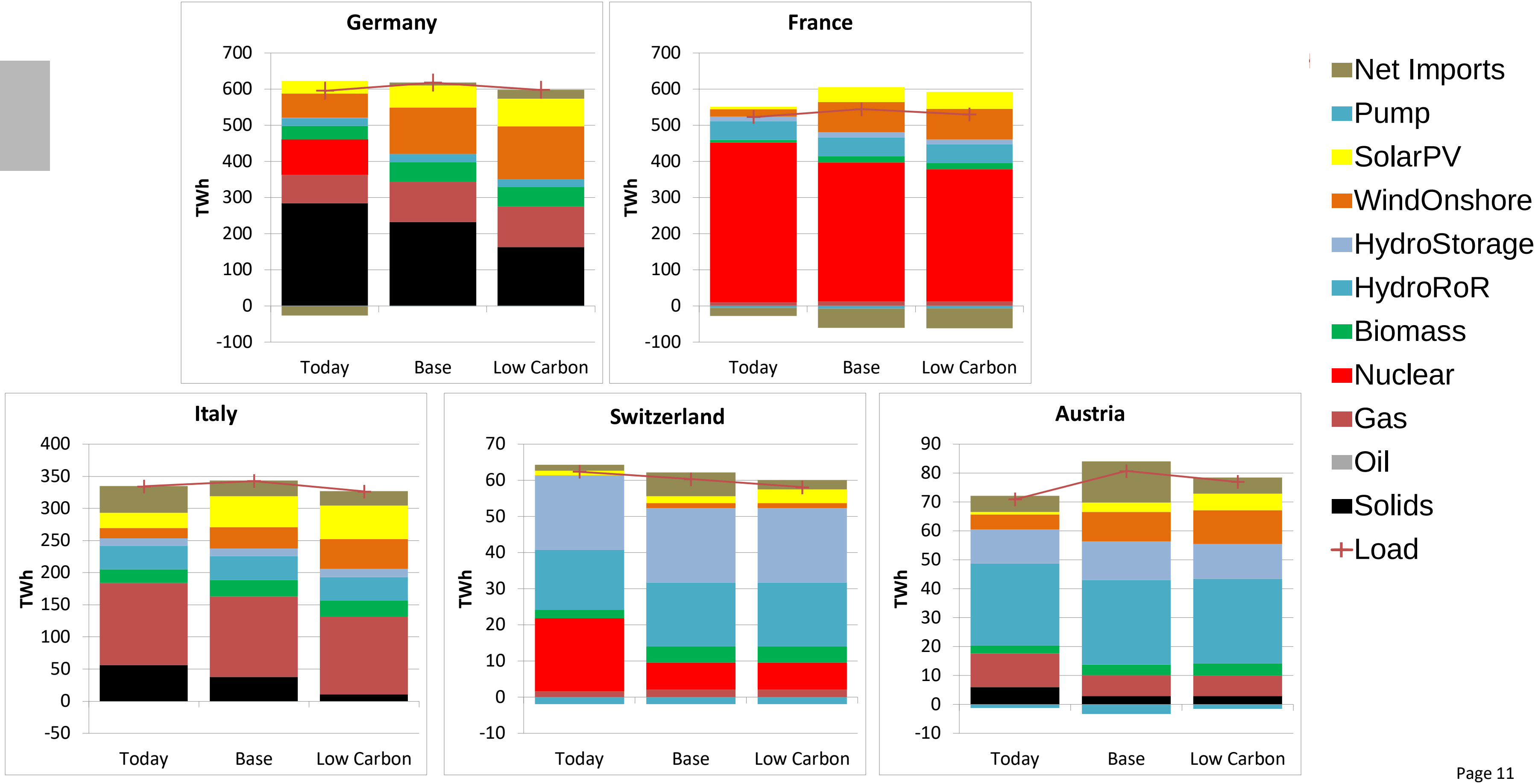
2030

Scenario	Lignite	Coal	Nuclear	Gas CC	Biomass/Waste
including the CO_2 price:					
Today	17	27 – 34	18	38 – 42	23 – 30
Base	40	54 – 61	18	80 – 84	23 – 30
Low Carbon	83	96 – 102	18	104 – 108	23 – 30
excluding the CO_2 price:					
Today	13	23 – 30	18	36 – 40	23 – 30
Base & Low Carbon	15	30 – 36	18	66 – 70	23 – 30

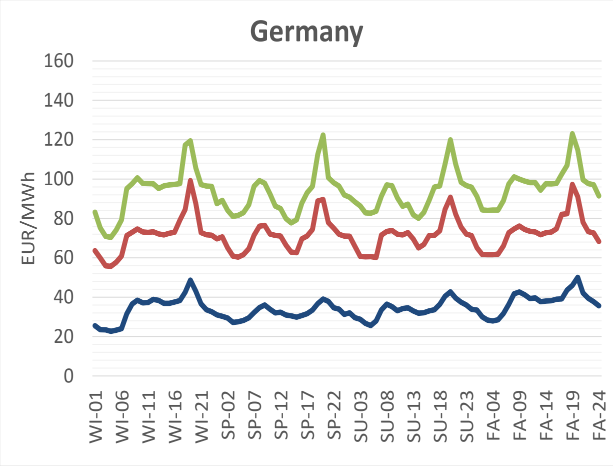
The increase of the fossil and CO_2 prices in 2030 from today's level leads to approx. 2x and 4x increase in marginal electricity production cost of fossils

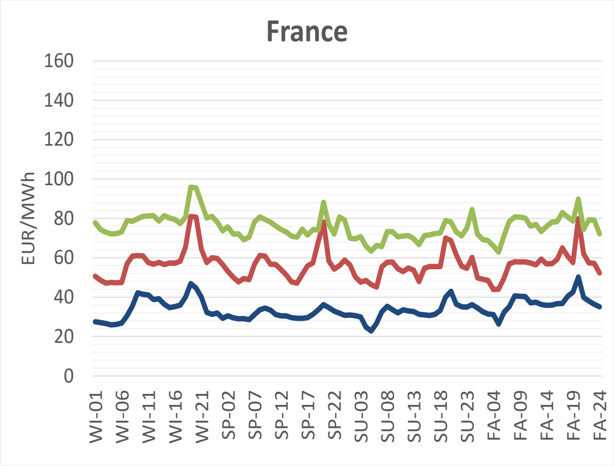
→ additional scenario variant «TodayCost» (fuel and CO_2 prices as today, i.e. 2015/16)

Results: Electricity generation mix today & in 2030



Results: Electricity prices today and in 2030

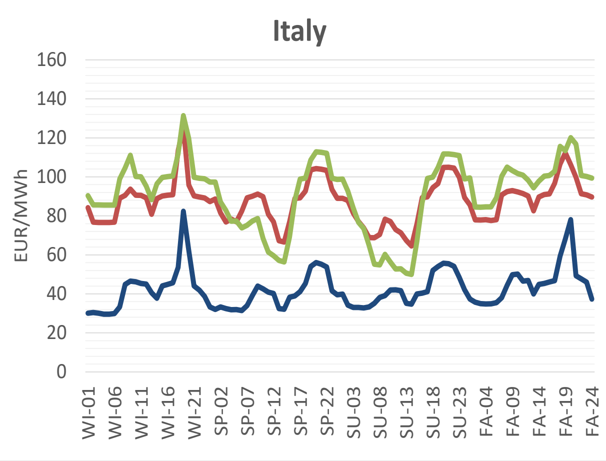


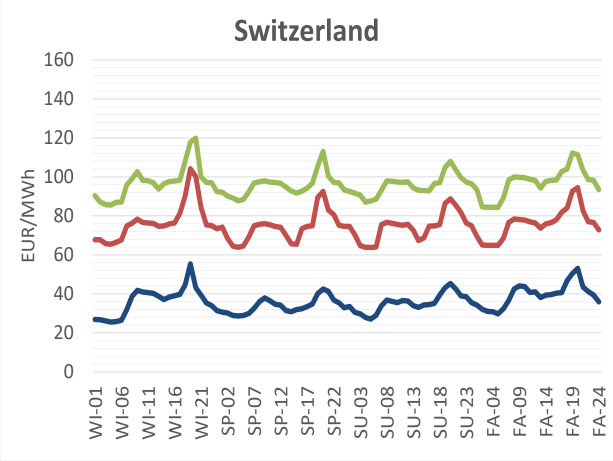


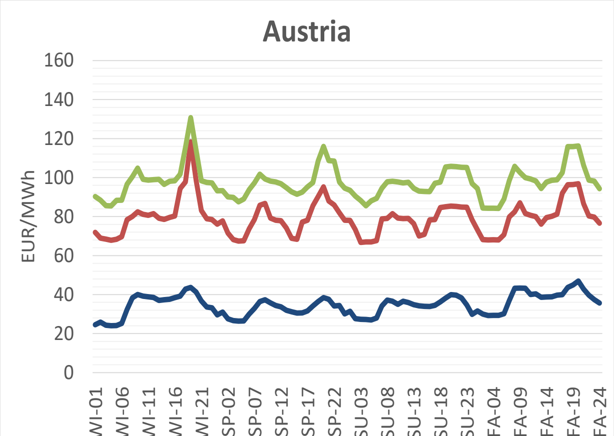
Low Carbon (2030)

Base (2030)

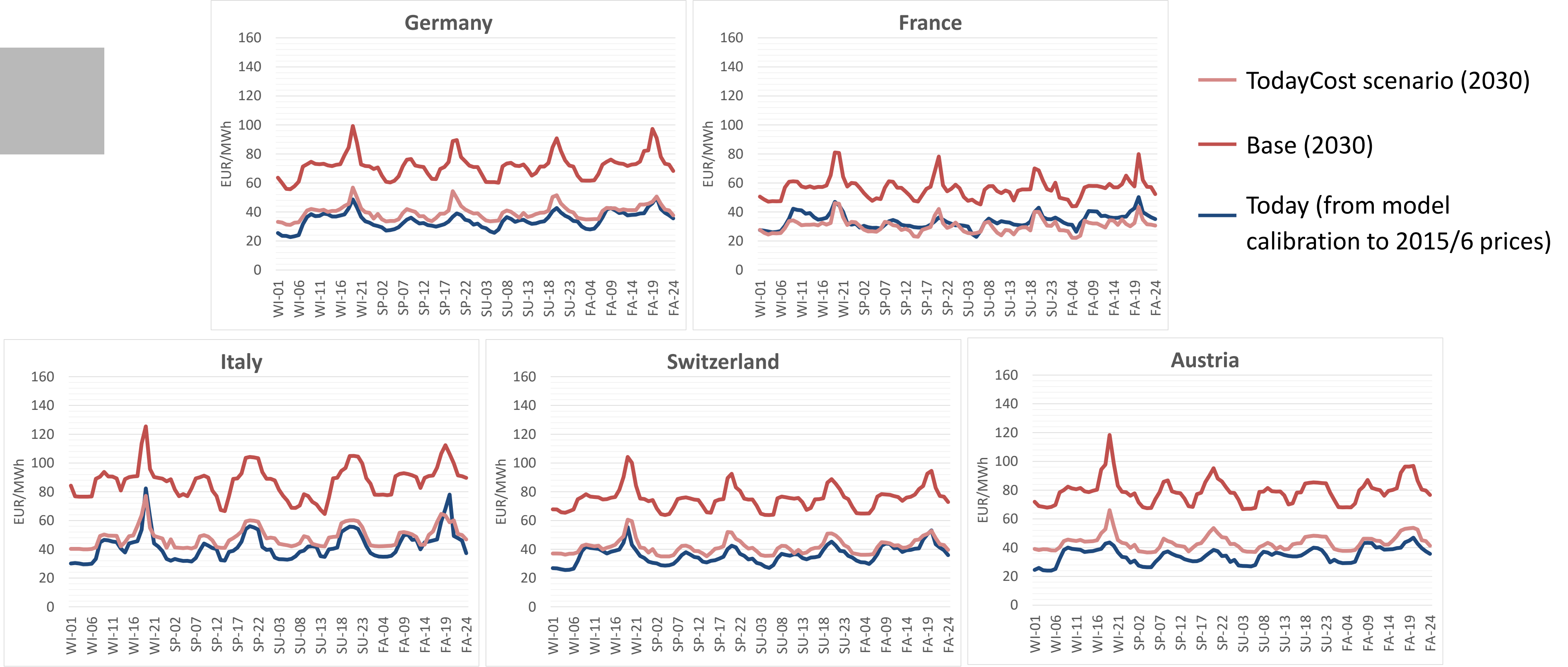
Today (from model calibration to 2015/6 prices)







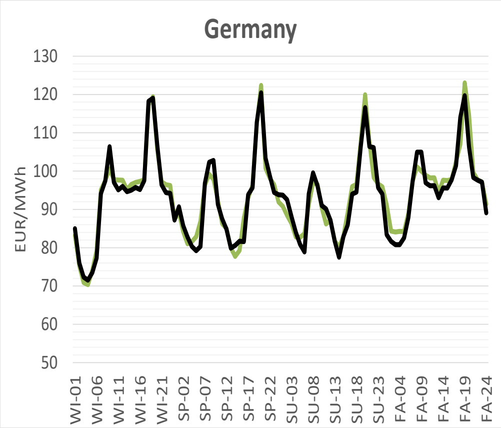
The TodayCost scenario reveals the drivers behind the price increase in 2030

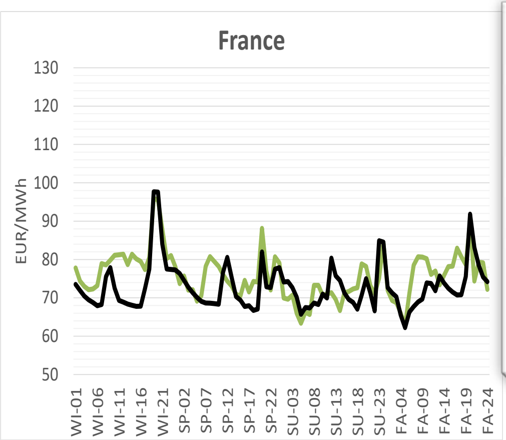


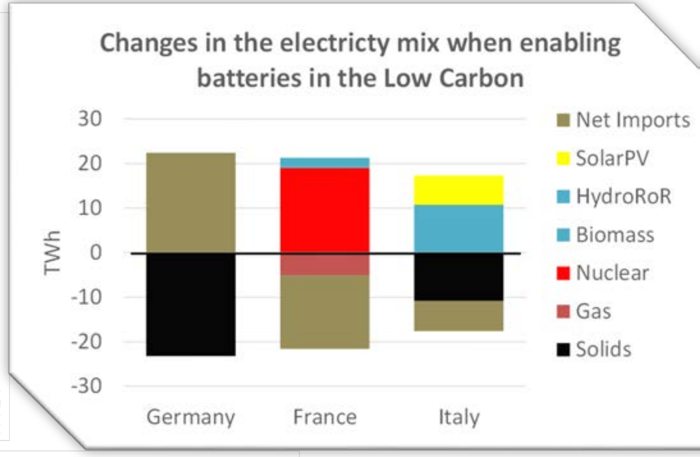
Drivers of the price increase in 2030: **(1) Fossil fuel price, especially gas (indirectly CO_2 prices),** (2) Load levels, (3) penetration of wind and solar, (4) decommissioning of the existing capacity

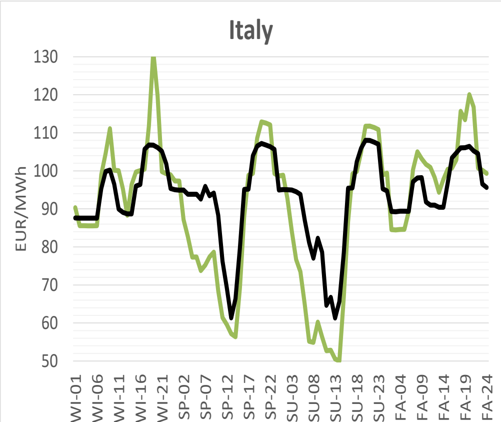
Results: Electricity prices and storage in 2030

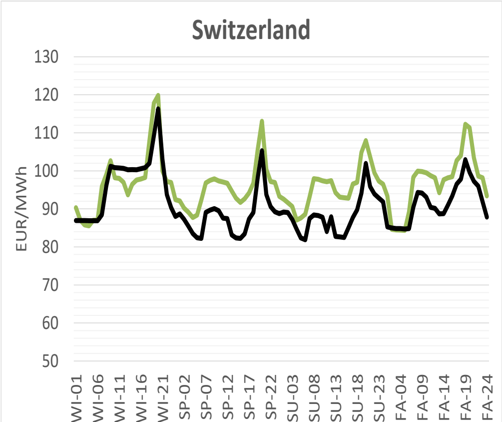
- Scenario variant: Low Carbon scenario with battery investments allowed

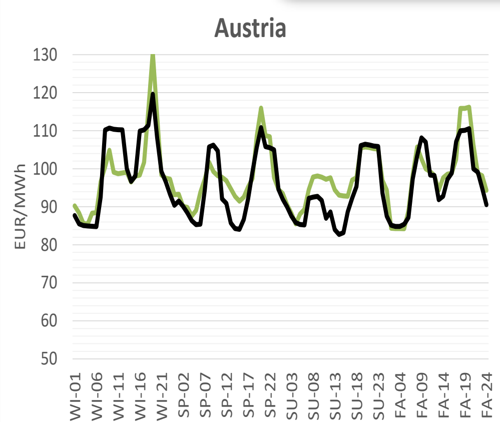












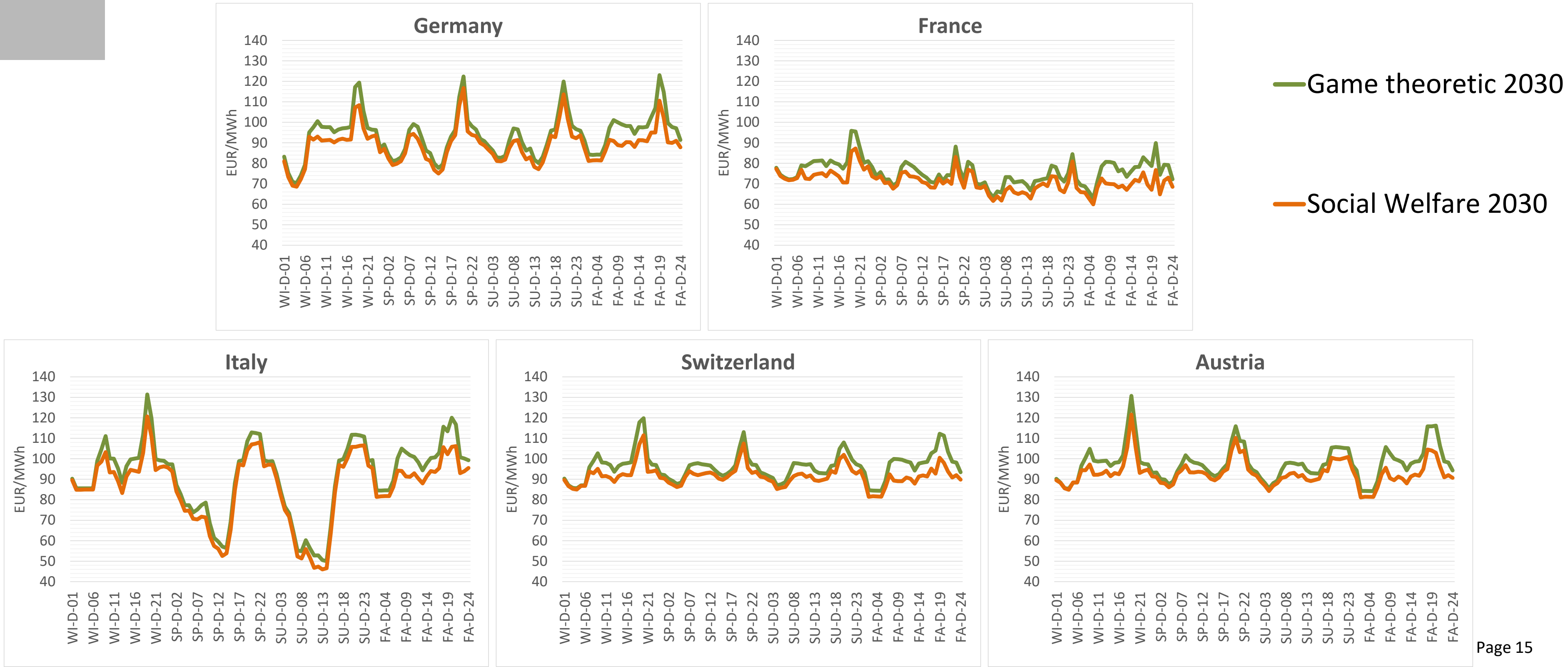
Investments in batteries:
Germany: 3 GW
France: 4 GW
Italy: 8 GW

Low Carbon

Low Carbon with batteries

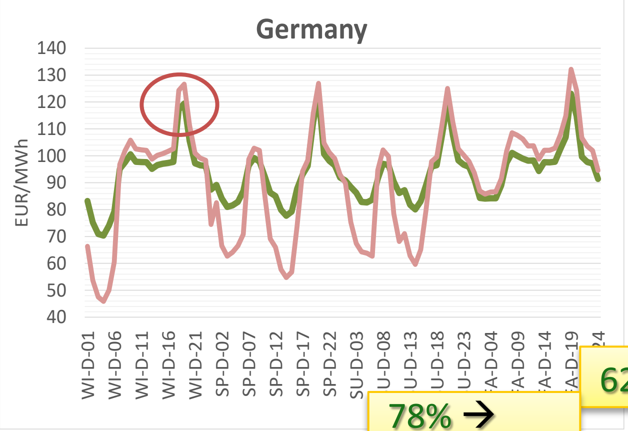
Evidence of strategic behaviour lessens over time

We compare the social welfare and the game theoretic solution in the Low Carbon scenario
→ hard to justify evidence of market power, some might be during the peak hours

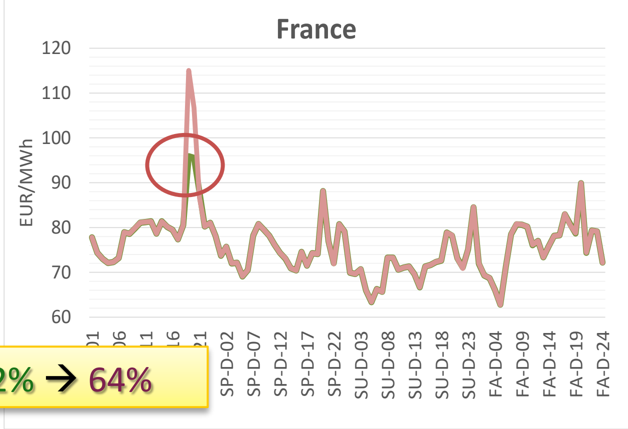


Market integration increases competition

When all NTCs are increased by 1 GW then a single price zone is gradually formed



78% → 92%

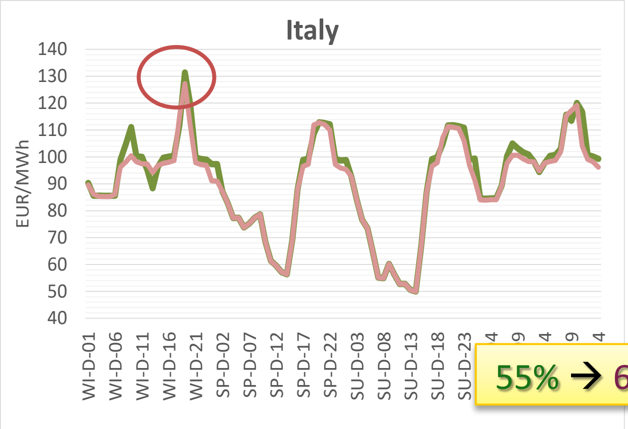


62% → 64%

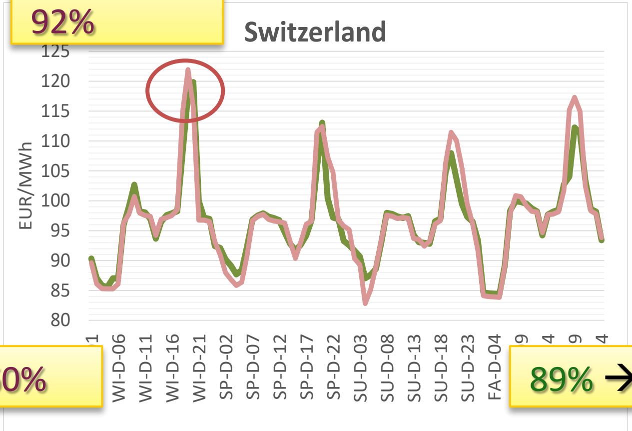
Low Carbon 2030

Low Carbon with high NTC 2030

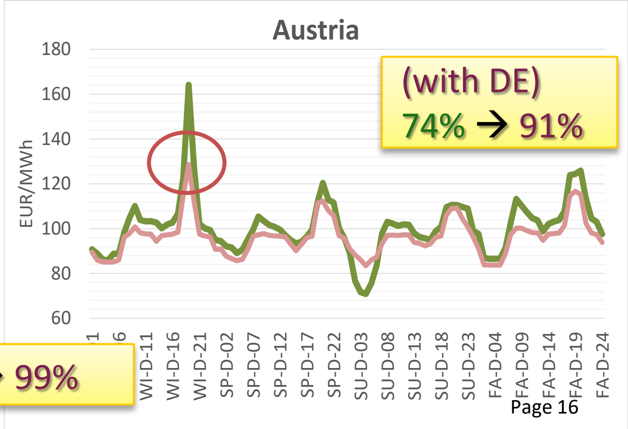
Price correlation %



55% → 60%



89% → 99%



(with DE)
74% → 91%

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Conclusions

- If **gas and CO_2 prices are rising** then electricity prices will raise again
  - In **Germany**, CO_2 prices have a greater impact on electricity prices than in the other countries due to the still remaining solid-based generation in the domestic supply mix
  - In **France**, prices follow the developments in the neighboring countries but remain the lowest
  - **Italy** remains a country with high prices due to the high domestic gas share; the high capacity factor of solar PV accentuates price dampening during noon
  - In **Switzerland**, prices closely follow the increase in gas price (even though the country does not build gas power plants; the country is a hub influenced by its neighbors)

- Intra-day **storage helps in mitigating peak prices and reduces volatility**, and in large scales can complement hydro storage (and participates in arbitrage trade)

- **Market integration** and **higher decentralization/non-dispatchable capacities** reduces the strategic behavior from producers

Thank you very much for your attention

Evangelos Panos

Energy Economics Group

Laboratory for Energy Systems Analysis

evangelos.panos@psi.ch

Publication (as of June 2018):

Project **"Oligopolistic capacity expansion with subsequent market-bidding under transmission constraints"** sponsored by the **Swiss Federal Office for Energy**

https://www.aramis.admin.ch/Default.aspx?DocumentID=46075

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Stylised formulation of BEM model

For each player* i:

max expected total profit = (profit from selling power – capital costs)

s.t.

- $\text{capacity}_i \leq \text{max\_capacity}_i$
- constraint on player's risk
- production-, imports-amounts, and prices given by:

  max total profit of player *i'*:

  s.t.

  - $\text{production}_{i'} \leq \text{capacity}_{i'}$
  - dispatching constraints (ramping rates, online/offline times, part load efficiency losses, minimum operating levels)
  - $\text{price}_{i'} = f_{i'}(\text{production}_{i'} + \text{net import}_{i'})$

** In the current model setup the players are Switzerland and its neighboring countries*

Stylised formulation of the BEM model

The TSO (price-taker) maximizes profit of redistributing electricity:

max total profit from distributing power across all nodes

s.t.

- constraint on no arbitrage (zero sum of distributed power)
- transmission grid constraints
- constraint on system security (enough dispatchable and storage capacity to accommodate variations of non-dispatchable generation and residual load curve)
- constraint on electricity balance of each node: demand = production +net imports)

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Why still Nash-Cournot modeling?

Market Power?

- Market power in CWE market is diminishing over time (e.g. Willems, 2009; Graf, 2013; Moutinho, 2014; Mulder, 2015) by transparency measures (e.g. blind auction, caps)
- Non-market factors of electricity price influence include: (i) Plant outages, (ii) Unforseen load variations, (iii) Share of power market day-ahead volume of total load

→ Shortage in market supply is not only caused by **deliberate** market power

- How to diminish difference between modelled marginal cost and observed prices?
  1. Model of all plants (1000+), heating days, outages, etc. → Commercial software
  2. Nash-Cournot with "as-if" market power → **Countries as players**, for simplicity