

Model-based Analysis of Possible Capacity Mechanisms until 2030 in the European Internal Electricity Market

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Capacity adequacy concerns

- ▶ Revenue adequacy concerns seem to emerge in the EU power generation market
- ▶ Merchant plant investors are reluctant, projects are cancelled and some new GTCC plants stopped operation
- ▶ Public and system authorities raised concerns about future capacity adequacy and discuss out-of-market actions including unilateral policies to remunerate capacity
- ▶ The European Commission questions unilateral actions from an IEM perspective

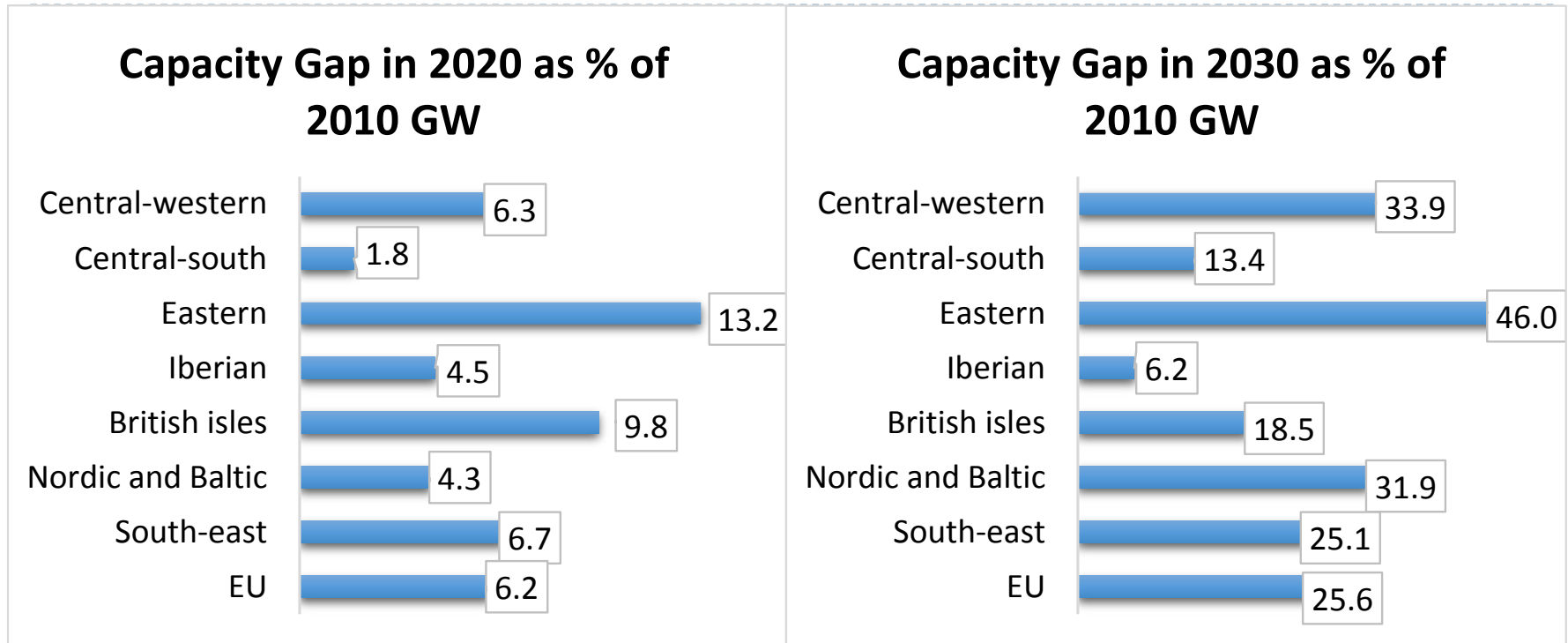
Possible causes

- ▶ The financial crisis having adverse effects on availability or conditions of financing
- ▶ The slowdown of growth causing electricity demand growing below expectations
- ▶ Over-capacity because of past practices and trends
- ▶ Rapid penetration of renewables and flaws in market design and operation
- ▶ The possible structural inability of energy – only markets to solve the missing money problem as demand responses are inadequately operating

Projection of Power Capacities

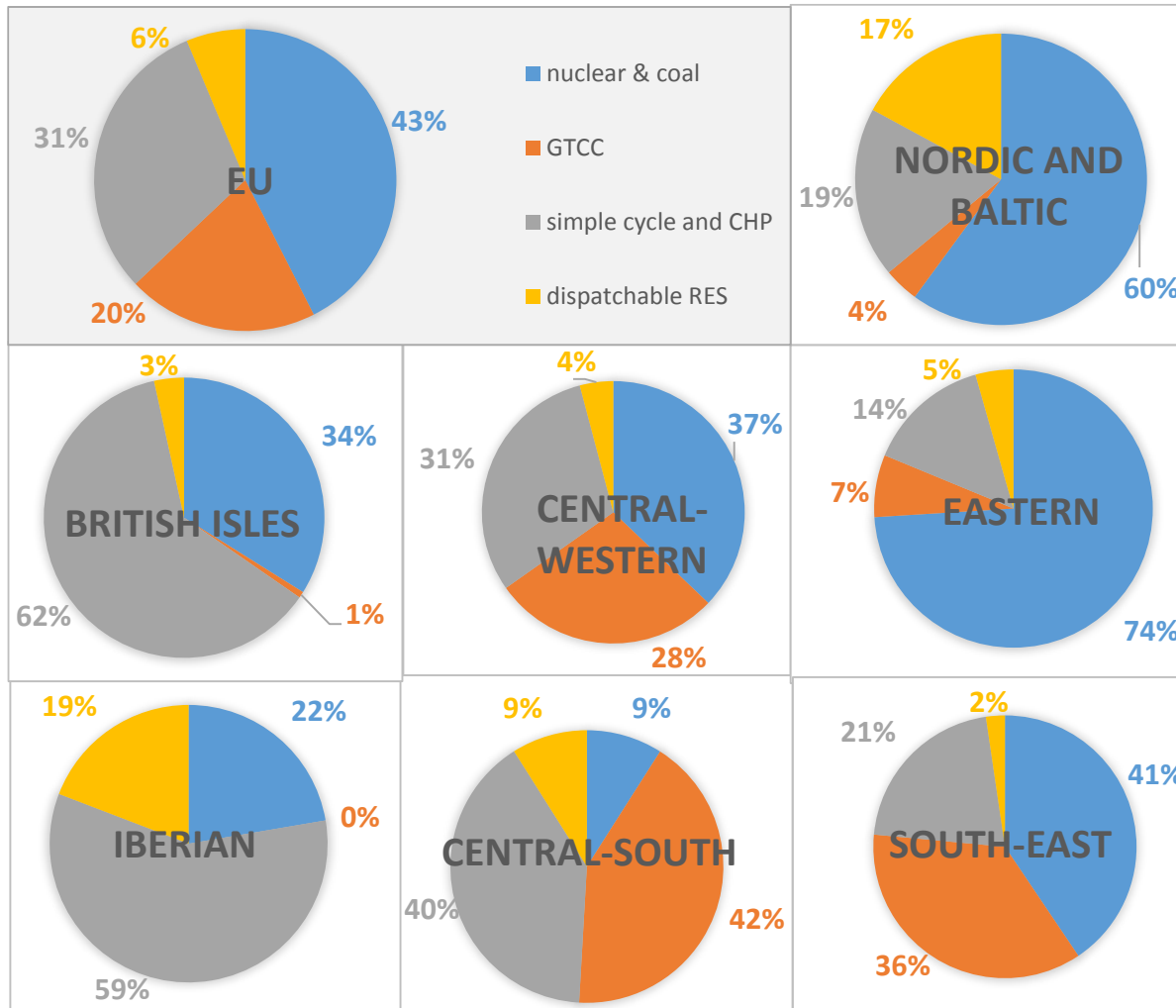
- ▶ Using PRIMES model and the Reference-2013 energy projection, endorsed by the European Commission
- ▶ Variable RES develop as planned: 25% of generation in 2020, close to 40% by 2030 (above 50% in lower carbon scenarios)
- ▶ Capacity gaps are projected until 2020 and in the decade up to 2030:
 - ▶ Small capacity gaps until 2020, but they increase significantly towards 2030
 - ▶ Flexibility requirements steadily increase
- ▶ Optimal capacity expansion until 2030 includes:
 - ▶ Simple cycle and CHP almost 1/3 of new dispatchable investment
 - ▶ Significant investment (40%) in base-load plants (nuclear, coal) both for new plants and for refurbishment
 - ▶ Fewer new GTCC (20%) compared to past trends

Projected capacity gap



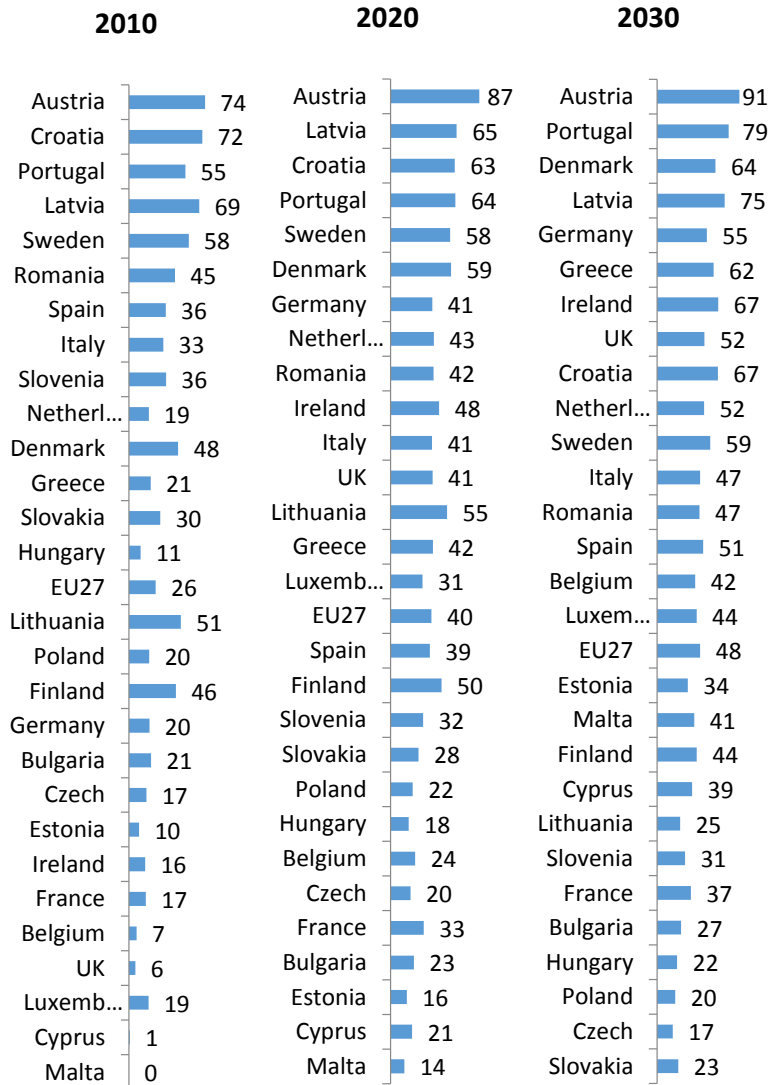
- Capacity gap projections include new investment which is under construction or is firmly decided and planned decommissioning, excluding uncertain projects
- Capacity gaps are calculated using reserve margins and reliability constraints, and take into account electricity trade between control areas

Projection of “optimal” investment



- ▶ Percentages of investment only in dispatchable plants including refurbishment
- ▶ The Reference scenario projects achievement of 2020 RES obligations and ETS carbon prices 10 in 2020 and 35 €/tCO₂ in 2030
- ▶ The projection assumes full recovery of all costs, including RES, capital and stranded costs

% share of must-take generation
(non dispatchable RES and CHP)



Impacts of must-take generation

- ▶ The share of must-take generation increases over time. Wholesale marginal prices are likely to be low in a high number of hours per year.
- ▶ The system requires increasingly higher system balancing and reserve services but the rates of use of flexible dispatchable plants are reduced. This despite assuming full implementation of the 10-year investment plan of ENTSO-E and flow-based allocation of interconnectors.
- ▶ Marginal price profiles present increasing risks for gas plants to recover capital costs, as recovery is over a smaller timeframe per year than in the past.
- ▶ Base-load plants are less affected by price profile changes but depend on base-load demand.

PRIMES simulating a EU-wide oligopoly competition

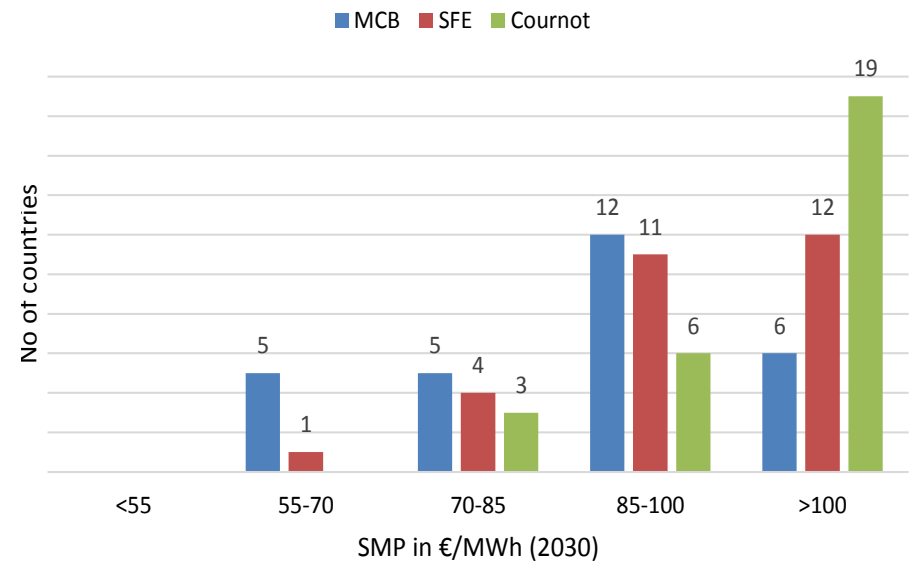
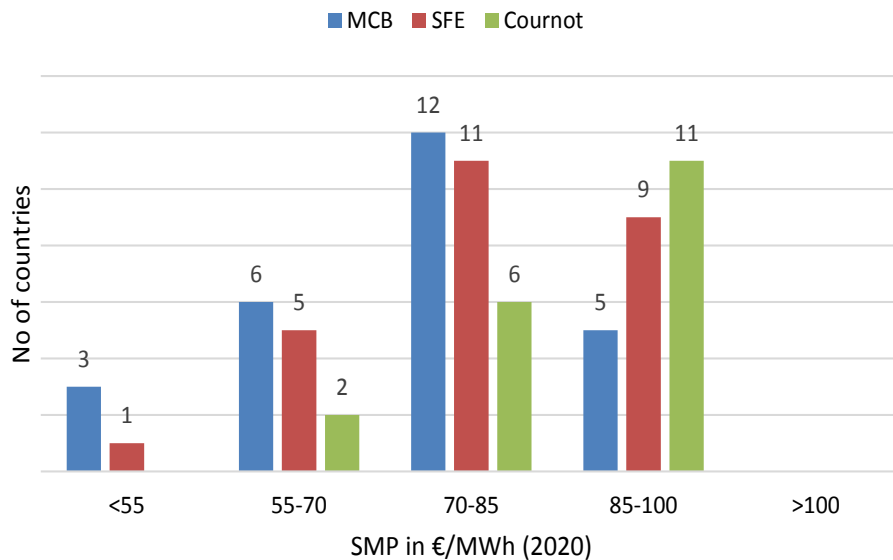
- ▶ Resolution: one node per country, multiple interconnectors with endogenous power flows over DC linear, many plant types, 9 typical days, deterministic variable RES, multiple years until 2050.
- ▶ Competition between companies owning generation and serving load, as well as between traders: conjectured supply function competition for several stylized cases (e.g. perfect competition, supply function equilibrium, Cournot, Stackelberg).
- ▶ Closes loop with demand which is endogenous depending on electricity tariffs. Tariffs by sector are cal mimicking practices (Ramsey-Boiteux method).
- ▶ Investment in generation results from intertemporal optimization, influenced by fuel prices, demand, ETS and the degree of capital cost recovery
- ▶ Reliability, ramping and reserve constraints oblige suppliers to invest, under endogenous trade flows in the IEM

Limitations of the model-based analysis

- ▶ The modelling has ignored uncertainty and imperfect anticipation
- ▶ General economic and financial conditions which may discourage investment are not taken into account
- ▶ The time resolution for capturing RES variability, ramping requirements etc. is limited to 9 typical days per year
- ▶ Grid limitations within system control areas (by country) are ignored
- ▶ RES are modelled in a deterministic not stochastic way and reserves for extreme events are ignored
- ▶ Implementation details of different possible capacity mechanisms are not modelled (outside scope)

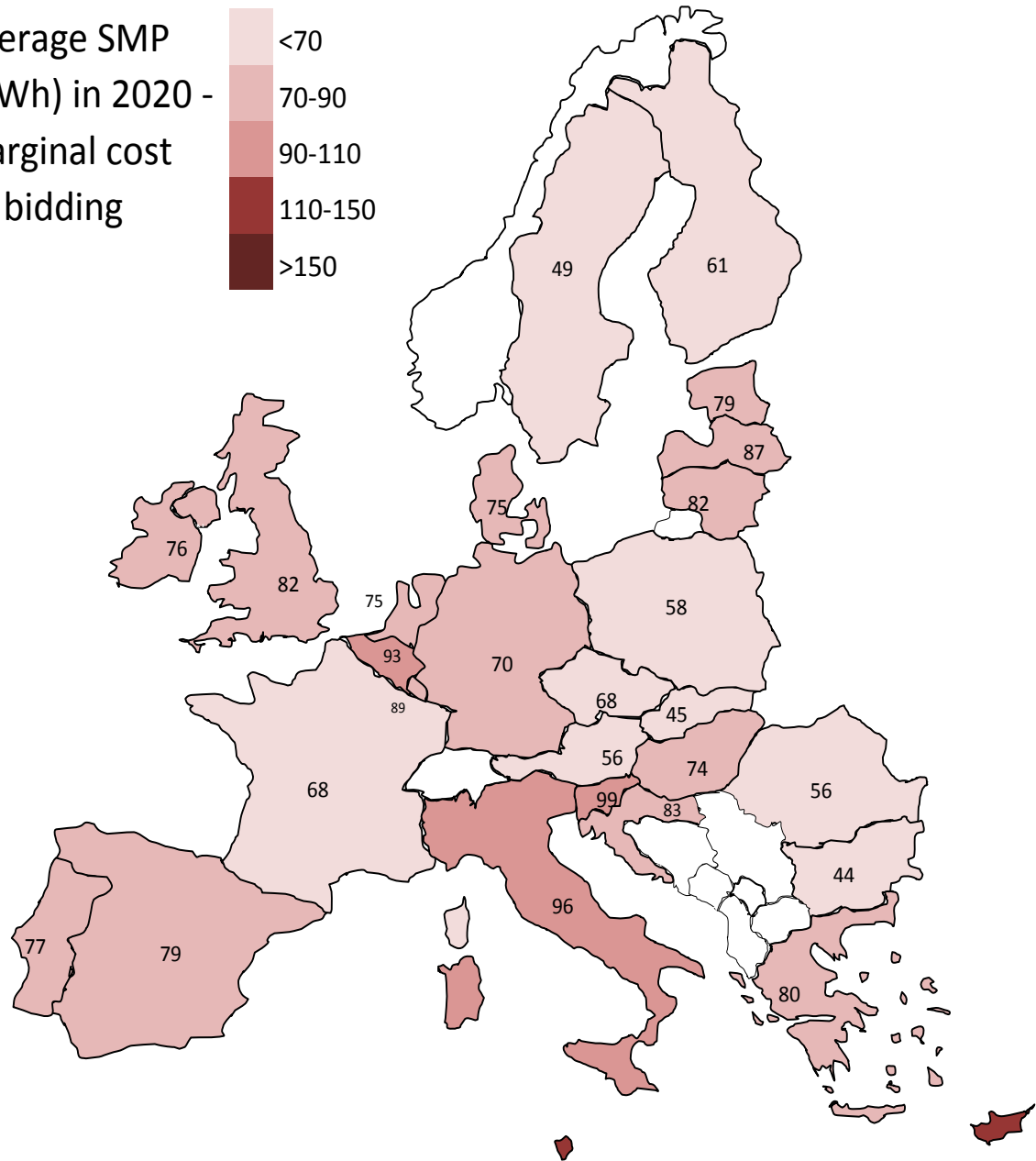
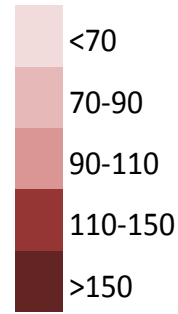
Average SMPs and bidding regimes

EU27	Marginal cost bidding			Supply function equilibrium		Cournot competition	
	2010	2020	2030	2020	2030	2020	2030
Average SMP (€/MWh)	40	65	76	69	82	79	90
Mark-up (% change over marginal cost bidding)				6.5	8.1	21.4	18.5



Simulation of virtual wholesale markets

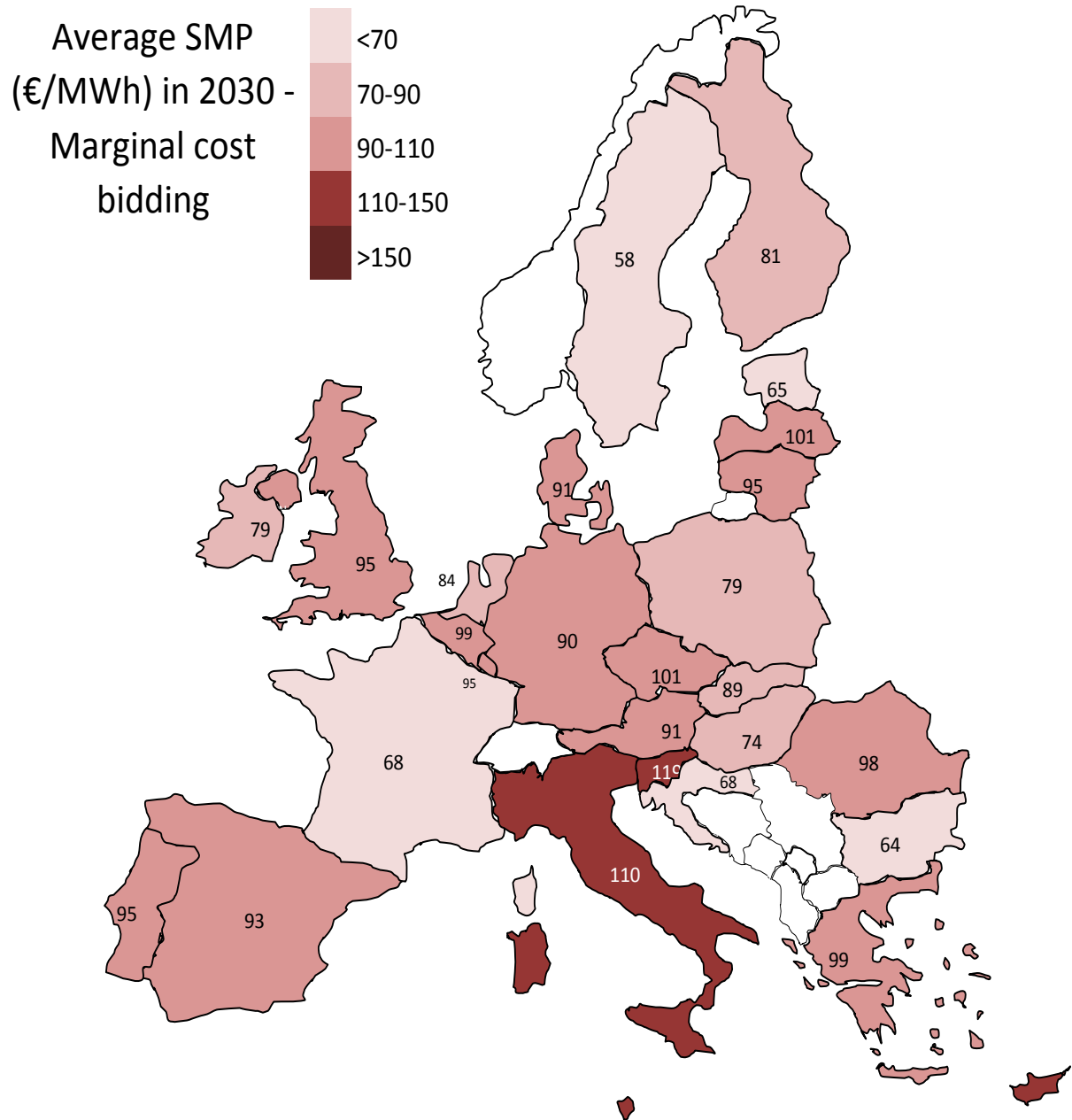
Average SMP
(€/MWh) in 2020 -
Marginal cost
bidding



- Despite significant increase of fossil fuel prices, average SMPs tend to increase less than expected because of the increasing share of must-take generation and the ramping constraints.
- Assuming wide market coupling and flow-based allocation of interconnectors (with increased capacities) leads to higher price convergence.

Simulation of virtual wholesale markets

- Average SMPs significantly increase in 2030 compared to 2020 even under perfect competition conditions.
- The main driver is the ETS price which escalates from a mere 10€/tCO₂ in 2020 to 35 €/tCO₂ by 2030.
- The price impacts are more pronounced in countries with high dependence on fossil fuels.
- Despite market coupling interconnection limitations do not allow average prices to converge as much as shown for 2020.



Capital cost recovery ratio of new dispatchable plants commissioned before 2030 (earnings from energy-only markets over 2015-2050, discount rates WACC 9%)

		Marg. Cost	SFE	Cournot	(blue above 1, red below 1)
Central-western	nuclear & coal	1.03	1.13	1.22	
	GTCC	0.55	0.71	1.24	
	simple cycle and CHP	0.27	0.19	0.31	
Central-south	nuclear & coal	1.34	1.35	1.47	
	GTCC	1.03	1.03	1.39	
	simple cycle and CHP	0.91	0.88	0.99	
Eastern	nuclear & coal	1.22	1.40	1.80	
	GTCC	0.42	0.56	0.65	
	simple cycle and CHP	0.36	0.48	0.60	
Iberian	nuclear & coal	1.05	1.10	1.14	
	GTCC	0.52	0.62	0.74	
	simple cycle and CHP	0.26	0.10	0.24	
British isles	nuclear & coal	1.11	1.15	1.19	
	GTCC	0.30	0.34	0.54	
	simple cycle and CHP	0.10	0.10	0.10	
Nordic and Baltic	nuclear & coal	1.07	1.18	1.47	
	GTCC	0.75	0.81	1.09	
	simple cycle and CHP	0.35	0.49	0.81	
South-east	nuclear & coal	1.10	1.18	1.40	
	GTCC	0.24	0.94	1.50	
	simple cycle and CHP	0.20	0.25	0.35	
EU	nuclear & coal	1.13	1.22	1.42	
	GTCC	0.57	0.76	1.11	
	simple cycle and CHP	0.35	0.38	0.53	

Capital recovery from energy-only markets

New nuclear and coal plants are projected to comfortably recover capital costs

GTCC fail to recover capital costs (roughly by 30% in SFE) except under Cournot competition

Simple cycle plants have trouble in recovering capital costs in energy only markets: they deliver flexibility which is not remunerated

Successful recovery of capital costs under SFE when accounting for plant portfolio

Capital cost recovery ratio of new dispatchable plants commissioned before 2030 (earnings from energy-only markets over 2015-2050, discount rates WACC 9%)

		Marg. Cost	SFE	Cournot	(blue above 1, red below 1)
Central-western	nuclear & coal	0.97	1.08	1.17	
	GTCC	0.24	0.28	0.72	
	simple cycle and CHP	0.33	0.27	0.46	
Central-south	nuclear & coal	1.31	1.33	1.45	
	GTCC	0.97	0.96	1.26	
	simple cycle and CHP	0.94	0.91	1.04	
Eastern	nuclear & coal	1.19	1.31	1.74	
	GTCC	0.42	0.45	0.55	
	simple cycle and CHP	0.42	0.39	0.58	
Iberian	nuclear & coal	1.07	1.11	1.14	
	GTCC	0.52	0.60	0.69	
	simple cycle and CHP	0.39	0.37	0.44	
British isles	nuclear & coal	1.12	1.16	1.19	
	GTCC	0.52	0.59	0.74	
	simple cycle and CHP	0.10	0.10	0.10	
Nordic and Baltic	nuclear & coal	0.97	0.99	1.15	
	GTCC	0.72	0.77	1.01	
	simple cycle and CHP	0.33	0.35	0.59	
South-east	nuclear & coal	1.09	1.08	1.36	
	GTCC	0.33	0.85	1.30	
	simple cycle and CHP	0.29	0.37	0.44	
EU	nuclear & coal	1.09	1.14	1.32	
	GTCC	0.53	0.65	0.94	
	simple cycle and CHP	0.39	0.39	0.54	

Capital recovery under High RES

Sensitivity analysis assuming Energy Roadmap RES development

Cumulative capital earnings decrease between 30 and 35% for nuclear and coal, 35-45% for GTCC and 12-15% for simple cycle plants

Nevertheless, base-load plants recover capital costs but GTCC do not (hardly under Cournot).

Portfolio revenues fail to recover capital costs under SFE



Low XB-trade

Average SMP (€/MWh)	Marginal cost bidding			Supply function equilibrium		Cournot competition	
	2010	2020	2030	2020	2030	2020	2030
Low XB Trade	40	74	86	80	89	87	97
Diff. from Reference	0.0	9.2	9.4	10.9	6.5	8.3	6.7
Mark-up (% change over perfect competition) in low XB trade				8.1	3.7	17.6	13.3
Diff. from Reference				1.6	-4.4	-3.8	-5.2

- ▶ The average SMPs increase by roughly 10€/MWh in all competition regimes.
- ▶ The mark-up ratios of imperfect competition regimes are smaller under low XB-trade because prices have increased relative to the Reference .

Capital cost recovery ratio of new dispatchable plants commissioned before 2030 (earnings from energy-only markets over 2015-2050, discount rates WACC 9%)

		Marg. Cost	SFE	Cournot	(blue above 1, red below 1)
Central-western	nuclear & coal	1.05	1.09	1.14	
	GTCC	1.17	1.36	2.12	
	simple cycle and CHP	0.34	0.31	0.47	
Central-south	nuclear & coal	1.22	1.36	1.48	
	GTCC	0.79	1.10	1.48	
	simple cycle and CHP	0.91	1.02	1.19	
Eastern	nuclear & coal	1.29	1.53	1.78	
	GTCC	0.43	0.67	0.91	
	simple cycle and CHP	0.98	1.13	1.55	
Iberian	nuclear & coal	1.05	1.10	1.12	
	GTCC	0.58	0.66	0.72	
	simple cycle and CHP	0.30	0.36	0.41	
British isles	nuclear & coal	1.10	1.16	1.20	
	GTCC	0.47	0.72	0.97	
	simple cycle and CHP	0.10	0.14	0.33	
Nordic and Baltic	nuclear & coal	0.78	0.89	1.14	
	GTCC	0.81	0.86	1.17	
	simple cycle and CHP	0.04	0.24	0.62	
South-east	nuclear & coal	1.52	1.17	1.49	
	GTCC	1.25	1.47	2.34	
	simple cycle and CHP	0.65	0.45	0.78	
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	GTCC	0.85	1.04	1.51	
	simple cycle and CHP	0.48	0.53	0.80	

Capital recovery under low XB-trade

Sensitivity analysis assuming strong NTC constraints and poor market coupling

Low XB trade implies higher use of GTCC and simple cycle plants as balancing is more concentrated nationally

This eases capital recovery of GTCC and simple cycle plants

Small but negative impacts for capital recovery of base-load plants

Calculation of capacity remuneration

- ▶ Estimated at 40-50 k€/MW-year on EU average on top of earnings from energy-only markets
- ▶ Conceived to focus only plants providing flexibility, excluding base-load plants, and implemented in a coordination manner
- ▶ Remuneration is roughly 3% of total cost of wholesale market
- ▶ Can be implemented through different market arrangements:
 - ▶ Real-time balancing markets
 - ▶ TSO contracts for ancillary and reserve services
 - ▶ Capacity mechanisms

Capital cost recovery ratio over plant lifetime including new and retrofitted plants	Perfect competition			SFE		
	GTCC	Simple cycle gas	Plant portfolio	GTCC	Simple cycle gas	Plant portfolio
Energy only market	0.2	0.1	0.8	0.7	0.2	1.0
With Capacity payment	0.8	0.6	1.0	1.0	0.9	1.1

Impacts of asymmetric capacity mechanisms

- ▶ We use the PRIMES EU wide oligopoly model.
- ▶ We quantify two stylized cases of asymmetric CMs, (only in France, or only in Germany), assuming capacity payment to gas plants, excluding base-load.
- ▶ We simulate change of investments according to assumed reaction of investors to asymmetric CMs.
- ▶ We evaluate impacts on cross border flows, on system prices, on costs etc. across the EU countries
- ▶ We compare to non asymmetric cases and we draw conclusions about possible distortionary impacts

Capacity payment only in France

- ▶ Assumption: 40 k€/MW to all gas plants only in France
- ▶ Higher investment in France, lower in Germany, Belgium and the Netherlands.
- ▶ XB trade impacts propagate across the EU with higher exports by France for balancing purposes.
- ▶ Under SFE competition, average SMP increases in France by 10%. German SMP decreases in the short term (-4% in 2020) and increases in the long term (3% in 2030). The EU average SMP increases by 1.3% in 2030.
- ▶ French gas plants improve capital cost recovery and base-load plants get extra earnings
- ▶ Total generation costs at the EU level are stable in 2020 and increase by 1.5% in 2030.

Capacity payment only in Germany

- ▶ Assumption: 40 k€/MW to all gas plants only in Germany
- ▶ Higher investment in Germany, lower in France, Belgium and the Netherlands.
- ▶ XB trade shows lower balancing imports by Germany and relatively small impacts on the rest of the EU.
- ▶ Under SFE competition, average SMP increases in Germany by 4%. French SMP increases in the short term (5% in 2020) and decreases in the long term (-4.9% in 2030). The EU average SMP increases by 1.3%.
- ▶ German gas plants improve recovery of capital costs but small impacts on other countries.
- ▶ Total generation costs increase by less than 1% in the EU.

Conclusions

- ▶ Capacity investment requirements until 2020 are significantly lower than in the decade after 2030.
- ▶ Must-take generation due to RES policies increases significantly over time implying a diminishing part of thermal plants in generation, lowering rates of use of thermal plants while reserve and balancing requirements are increasing.
- ▶ This problem becomes more acute in a decarbonisation pathway.
- ▶ The completion of the IEM and the implementation of grid investments accelerates price convergence. Failure in IEM completion implies higher costs with mixed impacts on capacity earnings.
- ▶ For energy only markets the modelling analysis shows:
 - ▶ Successful recovery of capital costs of base-load plants
 - ▶ Not sufficient recovery of capital costs by CCGT plants, except under Cournot competition; those commissioned before 2020 have more difficulties than those to be commissioned after 2020
 - ▶ Serious deficits for simple cycle gas plants

Conclusions

- ▶ The main issue is capacity adequacy for flexibility and reserve in supporting growing RES, rather than capacity adequacy in general
- ▶ A menu of possible measures exist for flexibility and reserve (real time balancing prices, ancillary services, reserve capacity procurement and targeted capacity remuneration).
- ▶ Assuming capacity remuneration targeted to simple cycle gas plants (or also to CCGT) capacity payments would represent a small fraction of total generation costs.
- ▶ If applied asymmetrically, the analysis shows:
 - ▶ Significant distortion of investment by country as well as of XB trade compared to optimal solution
 - ▶ Higher wholesale prices in the country that applies capacity remuneration and small decreases in prices in neighbouring countries
 - ▶ Higher generation costs for the entire EU, and in particular for the country which applies capacity remuneration