The Optimal Share of Variable Renewables

How the variability of wind and solar power affects their welfare-maximal deployment.

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My goals for today

- Paper submission to Energy Policy soon (April?)
- Feedback, input, ideas!

What is the welfare-optimal amount of wind and solar power?

- EU targets for renewables share in electricity supply: 35% in 2020, 60-80% in 2020, up from 17% in 2008 → Optimal? If so, what is the objective function?

- most growth will need to come from variable renewables renewable energy sources (vRES), mainly wind power [intermittent, fluctuating, non-dispatchable]

- vRES output is *uncertain*
  - forecast errors
  - system needs to provide flexibility in terms of ramping capacity
  - imbalance costs (vRES compared to perfectly reliable electricity source)

- vRES output is *variable*
  - exogenous generation profile driven by wind speeds / solar radiation
  - systems needs to ensure supply-demand balance at any point in time
  - electricity is not a homogenous good over time (fluctuating demand, set of technologies, expensive storage)
  - the value of one MWh depends on when it is generated
  - profile costs (vRES compared to constant electricity source)

What is the welfare-optimal amount of wind and solar power?

- Putting variability at the center of the analysis (but ignoring uncertainty)
- Taking existing infrastructure (generation, transmission) into account → medium-term perspective
- Taking crucial characteristics of the European electricity system into account that affect the value of electricity at each point in time (international trade, CHP, regulating power, pump hydro storage)

Many studies have optimized the vRES share, but few have taken variability seriously

- Integrated assessment models have a yearly resolution, while electricity prices vary significantly on the scale of hours (PRIMES, REMIND, EPPA, …)
- Long-term electricity sector models model several time slices per year, not sufficient to capture correlations and extremes (Short et al. 2003, Haller et al. 2011)
- Hourly-scale models of the electricity market often either take capacities as given (dispatch models) or optimize the conventional capacity for a given amount of vRES (Krämer 2002, Bushnell 2010, Green & Vasilakos 2011, Rosen 2007, Nicolosi 2012, Nagl et al. 2012, Hirth 2012, Hirth & Ueckerdt 2012)
- A handful studies optimize vRES capacities based on a high-resolution model, but often with crucial methodological shortcomings (DeCarolis & Keith 2006, Olsina et al. 2007, Lamont 2008, Doherty et al. 2006, Denny & O'Malley 2007)
  - small model region (one country)
  - unrealistic wind / solar profiles
  - very stylized representation of conventional generation and system constraints
  - not taking existing capacities into account

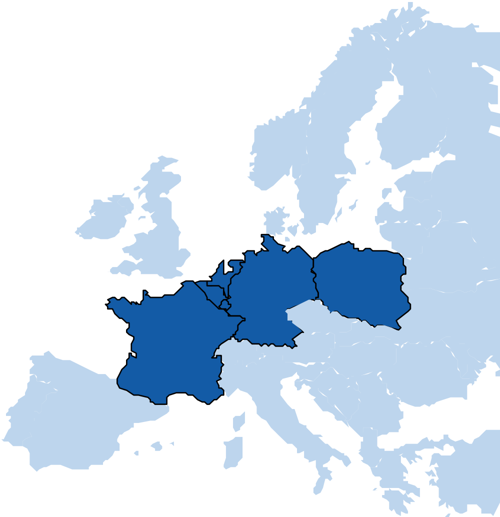
Three contributions

- Endogenous investment model combined with existing plant stack
  (mid-term perspective)
  → policy relevance

- Crucial features of the electricity system
  (CHP, ancillary services, transmission constraints, empirical vRES profiles)
  → realistic results

- Effect of policies, prices, and parameters on the optimal vRES share
  (vRES costs, CO_2 and fuel prices, market integration, storage, vRES profile)
  → sensitivities and uncertainty range

- stylized electricity market model
  - total system costs are minimized with respect to investment and dispatch decisions under a large set of technical constraints
  - ten technologies (wind, solar, eight thermal, pump hydro)
  - no market power or other market imperfections, thus central cost minimization is equivalent to decentralized profit-maximization
  - existing plant stack, storage and interconnectors are sunk, but endogenous (dis-) investment is possible
  - no load flow, NTCs between market areas
  - perfectly price-inelastic demand
- variability well represented
  - hourly time steps for a full year
  - time series based on historical weather to capture correlations over time, across space, and between variables
- parameterization of key system inflexibilities
  - CHP must-run
  - start-up costs
  - ancillary services
- back-tested to market prices
- used for Redistribution paper (yesterday), Market Value paper (YEEES)



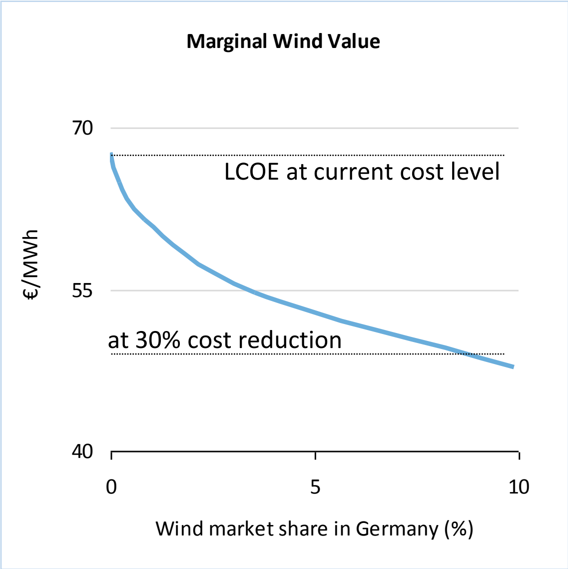
Results

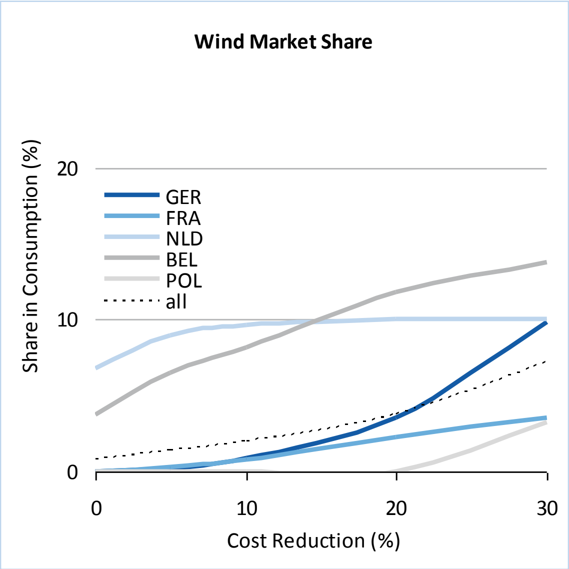
- for each set of parameters a number of runs where wind costs are decreased by 0%...30% and solar costs by 0%...60%

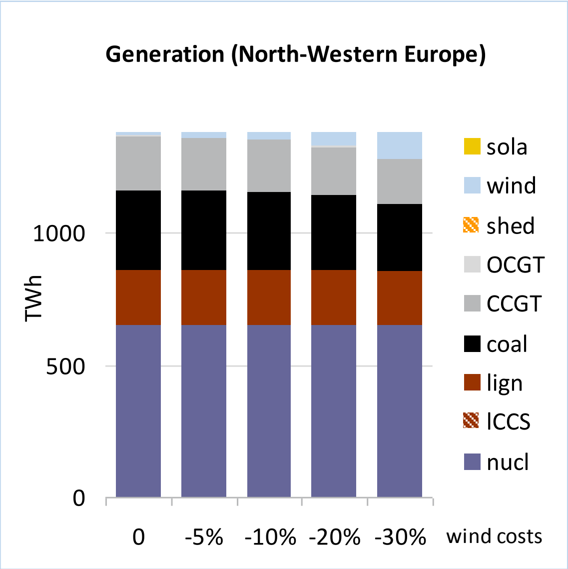
- benchmark
  - CO_2 price 20 €/t
  - hard coal price 12 €/MWht (130 €/t) and gas price 24 €/MWht
  - interconnectors and pump hydro storage as today
  - spinning reserve and CHP must-run constraints hold
  - all generation technologies are available for new investments

- additional runs
  - effect of variability
  - CO2 pricing
  - very high cost reductions
  - long-term equilibrium
  - Paper: nuclear and CCS unavailable, fuel prices, interconnector and storage capacity, system and plant flexibility

Benchmark

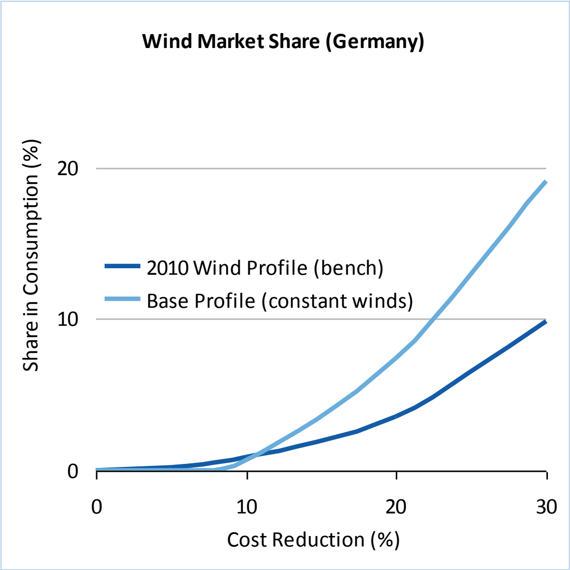


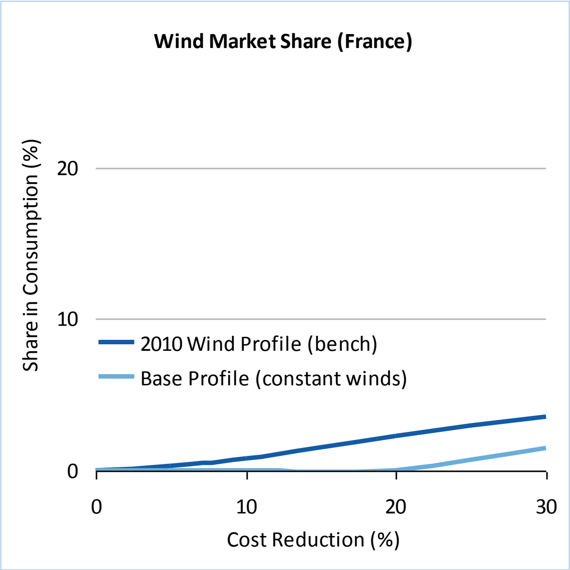




- the value of wind power (€/MWh) declines with wind capacity (Hirth 2012)
- for a given level of wind generation costs, the optimal level of wind penetration is reached where marginal costs equal marginal benefits
  (in market terms: where costs of new turbines equals revenues)
- with the currently installed capacity, current fuel prices, and current cost parameters, the optimal wind share is 1% of total consumption
- if wind costs decline by 30% (70 €/MWh to 50 €/MWh), the optimal share is 7%

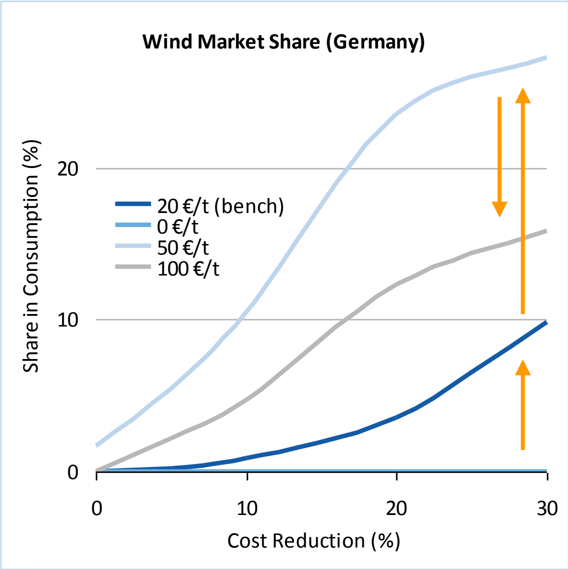
Variability

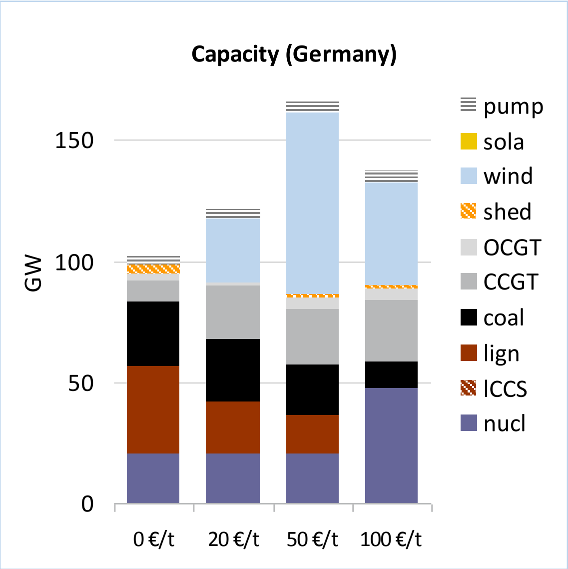


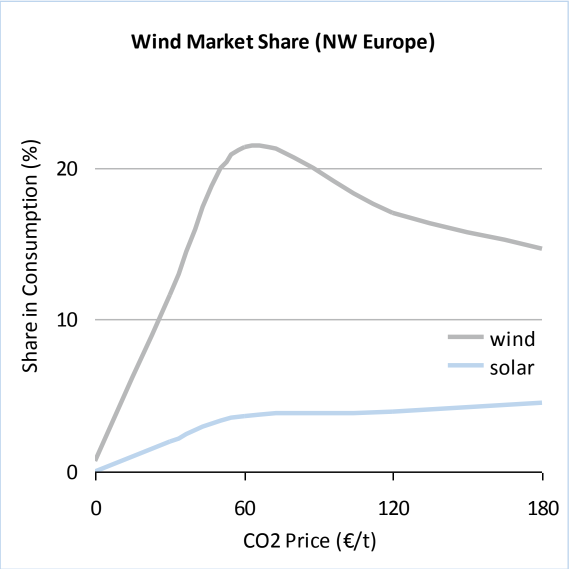


- with the real 2010 wind profile, the optimal market share of German wind power rises to 10%
- if winds were constant, the optimal share was 20%
- → variability reduces optimal deployment by half
- vice versa in France: cheap base load capacity limits the value of additional base load capacity, but real wind profiles are well correlated with demand

CO_2 pricing

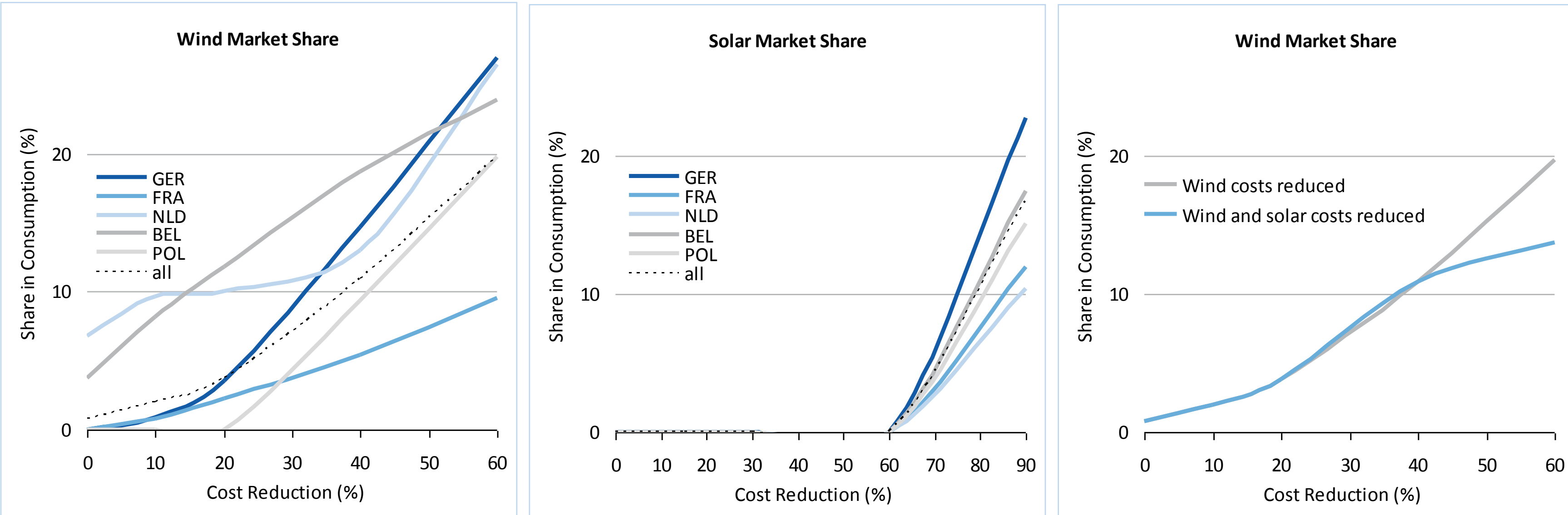






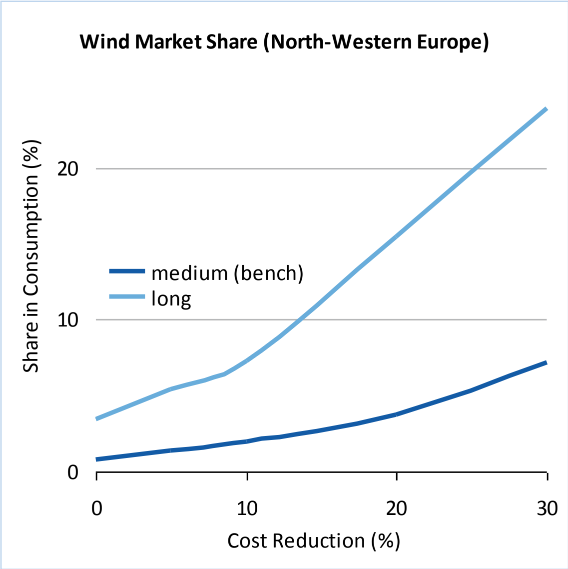
- benchmark CO_2 price: 20 €/t
- lower CO_2 price (0 €/t) induces less wind deployment (cheaper alternatives)
- higher CO_2 price (50 €/t) induces more wind deployment (alternatives more expensive)
- even higher CO_2 price (100 €/t) induces *less* deployment (inflexible low-carbon base load technology nuclear limits the value of wind)

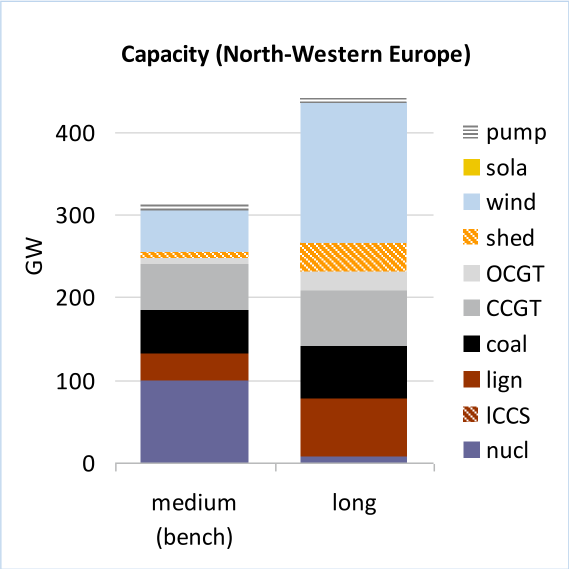
Very high cost reduction



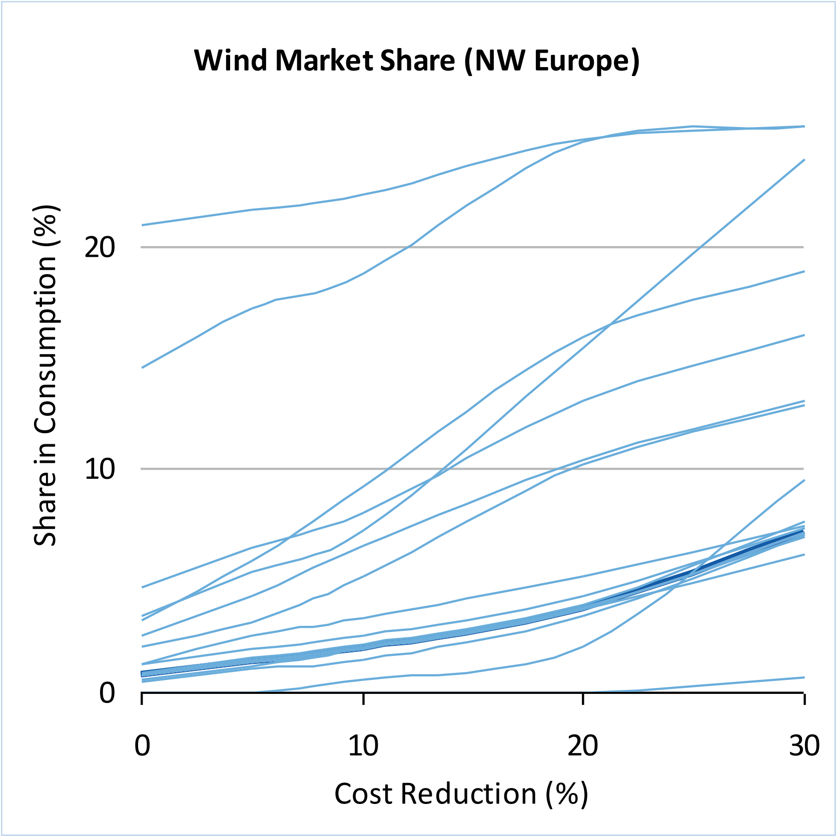
- even with dramatic cost reductions (-60% wind, -90% solar), the optimal wind share remains at 20% and the optimal solar share at 17%
- solar power’s role remains small even if generation costs drop to 20 €/MWh (a third of nuclear’s costs)

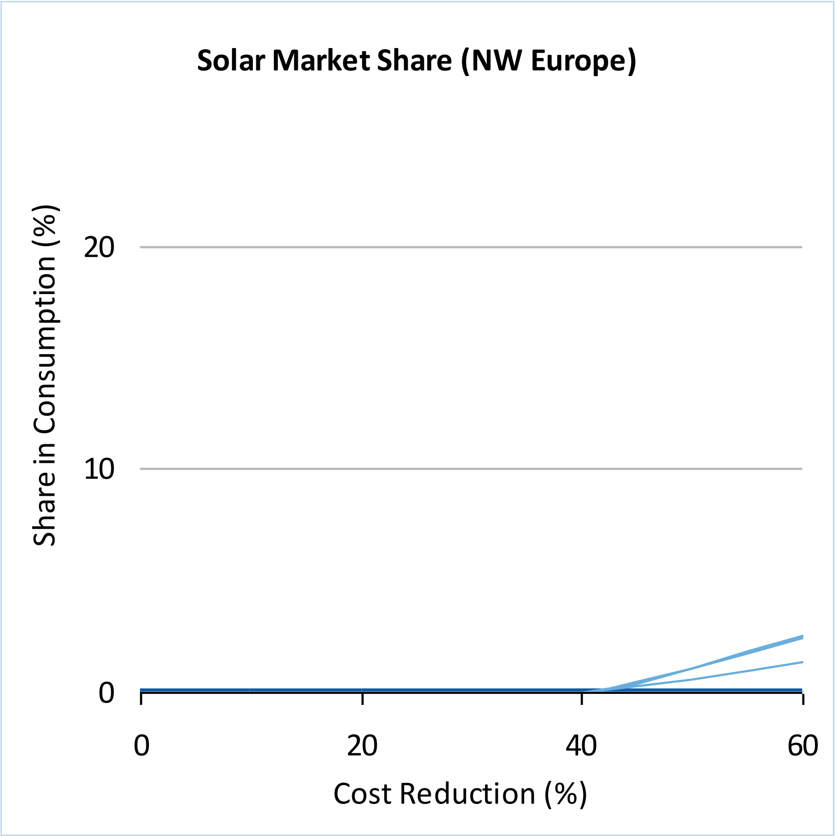
Long-term equilibrium





- so far: existing generation capacity taken as given (mid-term)
- long-term: all capacity is endogenous
- long-term equilibrium results in much higher optimal wind shares (25% at high cost reductions), zero solar deployment (even at 60% cost reduction) and a shift from base to peak load technology


Wind Market Share (NW Europe)
Share in Consumption (%)
0
10
20
0
10
20
30
Cost Reduction (%)


Solar Market Share (NW Europe)
Share in Consumption (%)
0
10
20
0
20
40
60
Cost Reduction (%)

Conclusions

- Variability reduces the value of wind and solar power massively once large amounts are installed (profile costs matter)
- At 30% cost reduction, variability reduces the optimal amount of wind power in Germany by half
- Even at very significant cost reductions, the optimal mid-term wind share in North-Western Europe remains below 10% and the optimal solar share at zero
- Several factors increase the optimal wind share strongly (moderately higher CO_2 prices, nuclear phase-out, hard coal prices) to around 20%, others don't (transmission investments)
- solar power is virtually never deployed in the optimum
- In the long-run equilibrium, wind's market share is 25%, three times the optimal medium-term value
- → A low-carbon peak-technology is needed to supplement vRES in the transition to a low-carbon electricity sector (wind and solar won't do the job alone)

Questions?

Comments?

Ideas?

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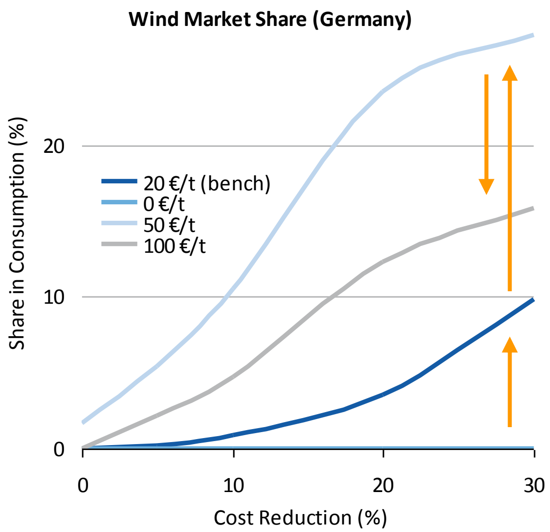
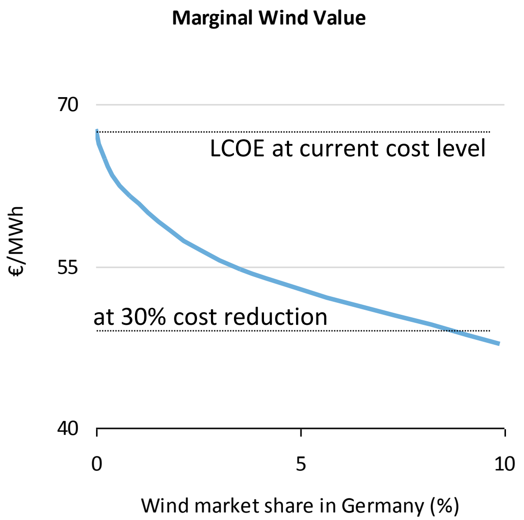
- Is the medium-term optimum or the long-term optimum more relevant for policy making?


Wind Market Share (Germany)
Share in Consumption (%)
20
10
0
20 €/t (bench)
0 €/t
50 €/t
100 €/t
0
10
20
30
Cost Reduction (%)


Marginal Wind Value
€/MWh
70
55
40
LCOE at current cost level
at 30% cost reduction
0
5
10
Wind market share in Germany (%)