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Electricity markets with a predominant share of renewable generation ***Can competition survive?***

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Two roads diverged... *(Robert Frost 1875)*

1996

Directive 96/92/EC of the European Parliament:

1. **enable competitive electricity markets (2)**

2010

EPEXSPOT EN | FR
EUROPEAN POWER EXCHANGE
TOWARDS THE PAN-EUROPEAN POWER MARKET

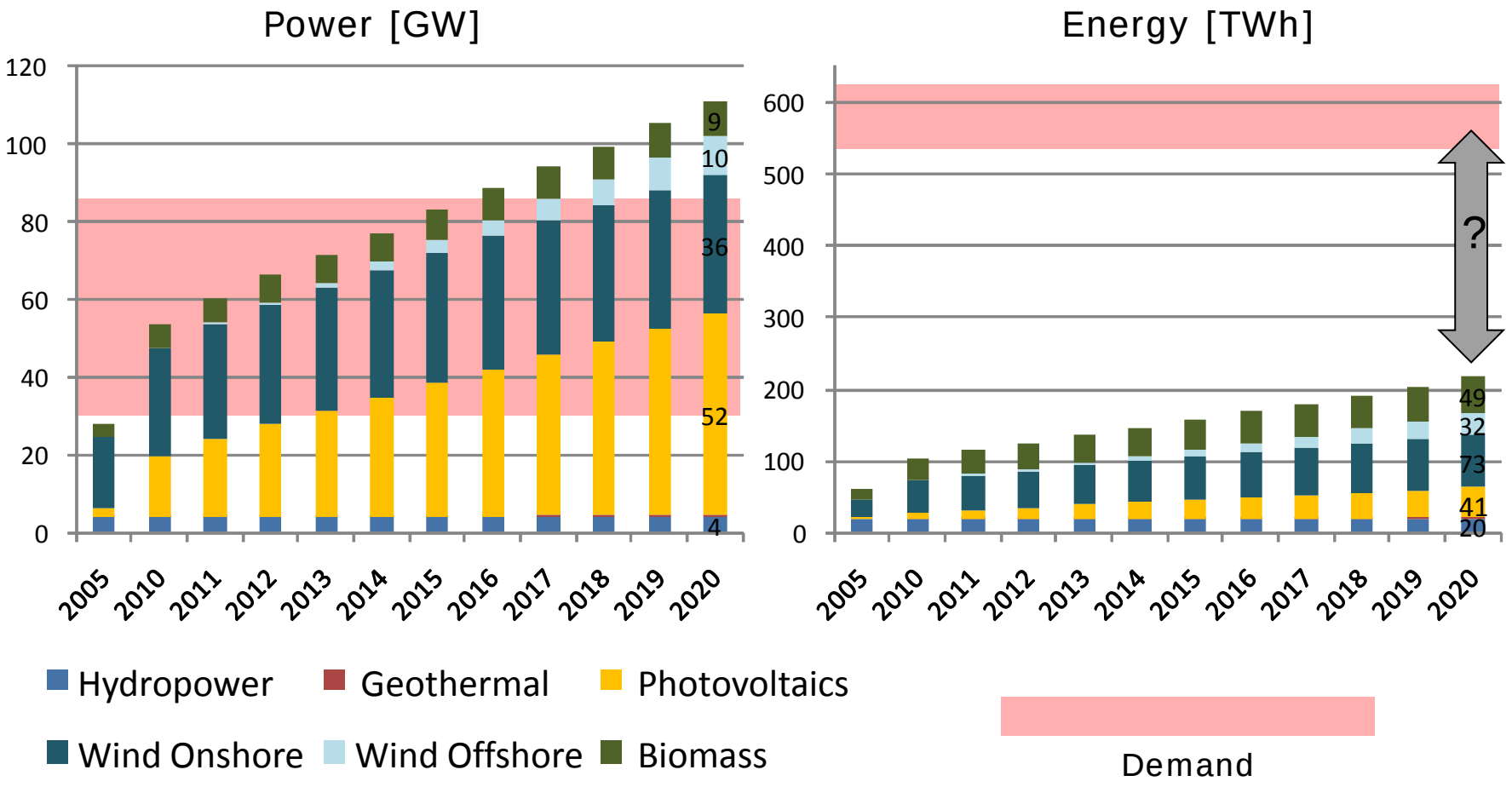
www.epexspot.com

2. **priority may be given to the production of electricity from renewable sources (28)**

www.n-pv.de

German National Renewable Energy Action Plan - Electricity

Explicit promotion of specific technologies by means of feed-in tariffs

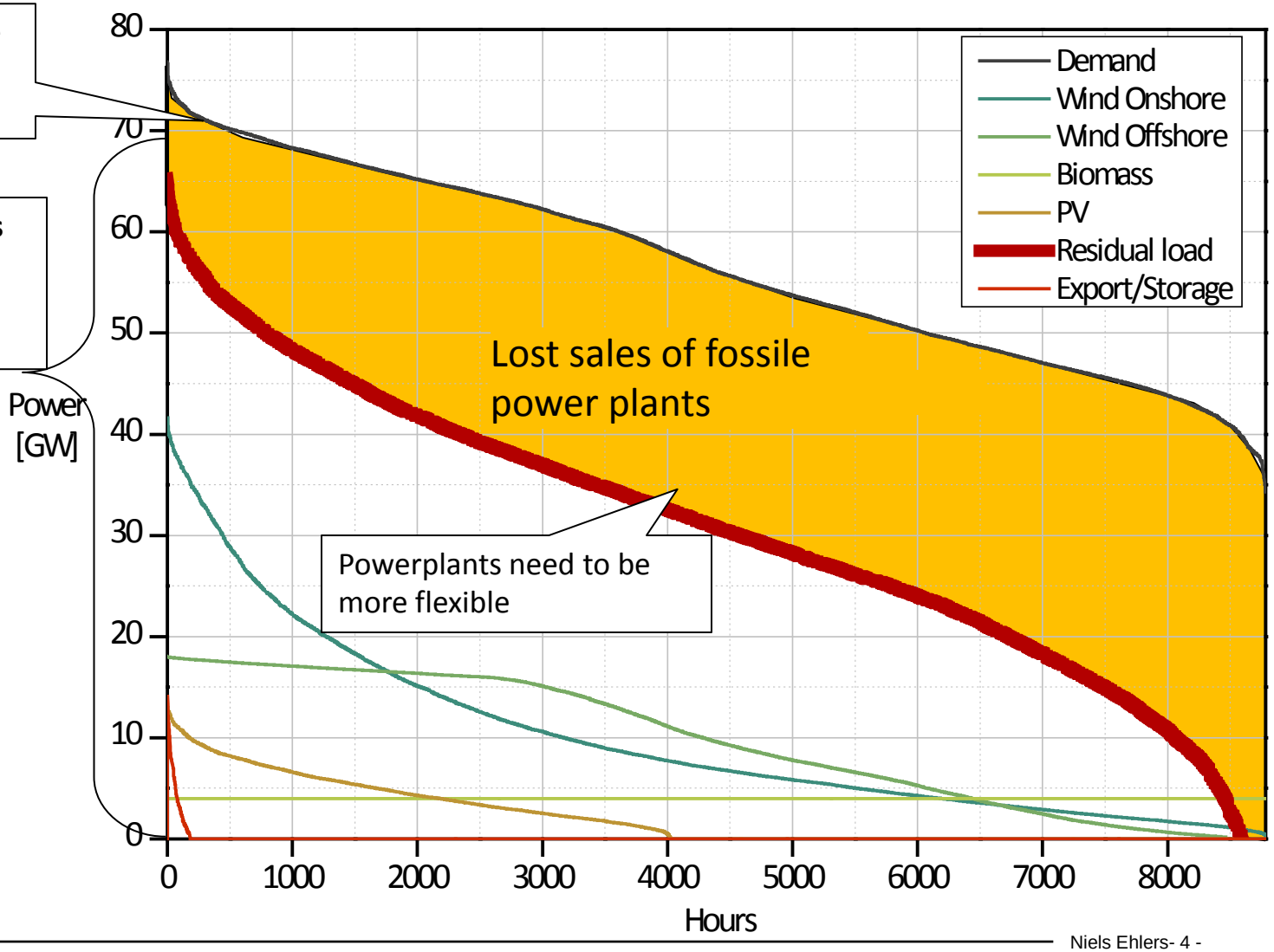


Source: Nationaler Aktionsplan für erneuerbare Energie gemäß der Richtlinie 2009/28/EG zur Förderung der Nutzung von Energie aus erneuerbaren Quellen

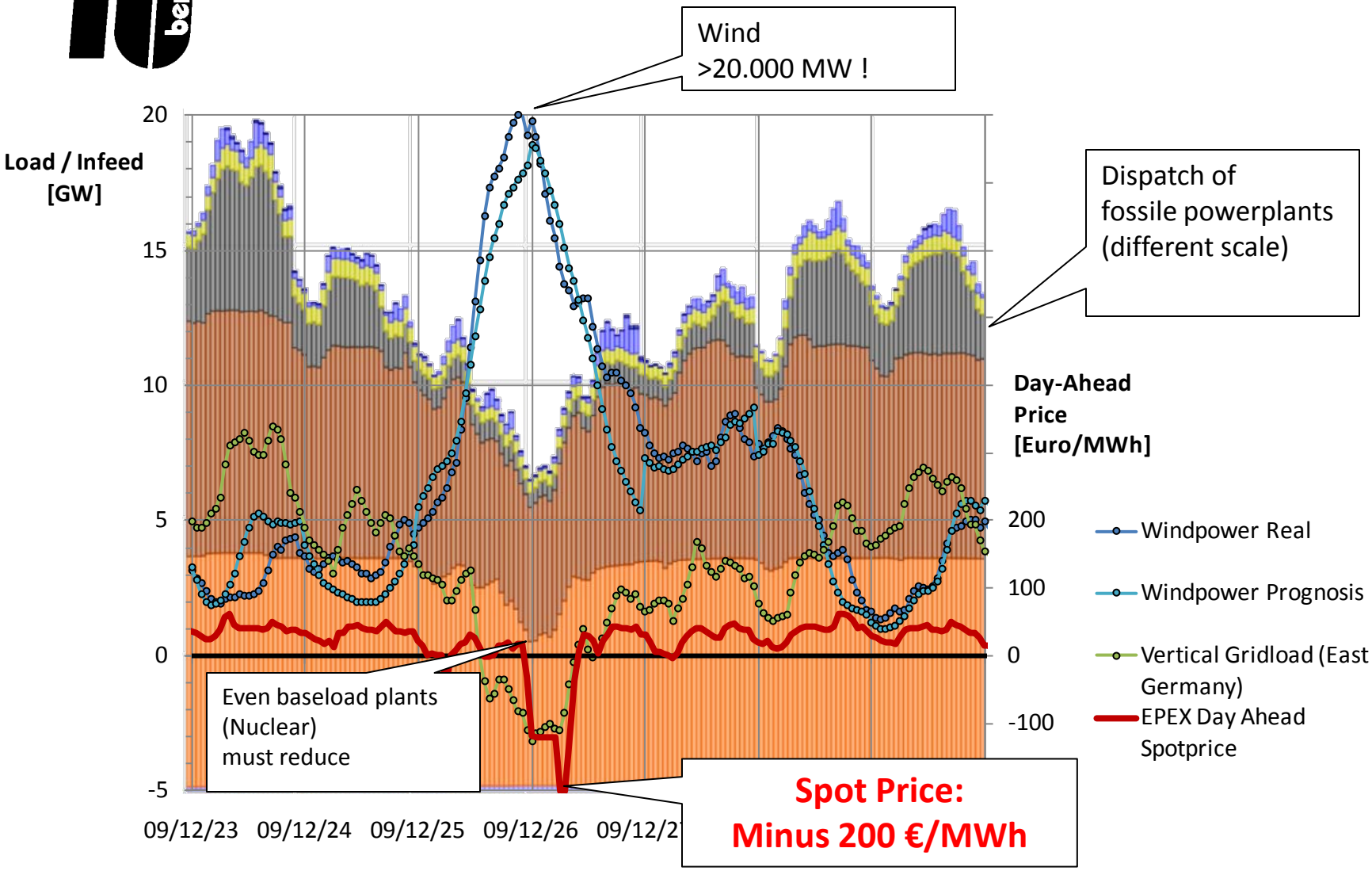
Scenario 2030 - Residual load with growing shares of renewable generation

Little change in peak demand!

How can this capacity be financed?



The result: Grid situation Christmas 2009



Back to the basics: market fundamentals

- All markets are based on the trade of **limited (constrained)** goods or resources.
- Each constrained resource can be assigned a **shadow price** of relaxing this constraint (i.e. expand production) by one unit.
- The price should be made equal to **marginal cost**.
- When average costs are decreasing, marginal costs are less than average costs, the total amount paid for the product will fall short of total costs

See for example: R. H. COASE 1946: The Marginal Cost Controversy

A market perspective on electricity I

Specifics of the electricity market:

- Different technologies with highly varying cost factors
- Short –run marginal costs (SRMC):
  - consumption of primary energy (coal, gas, U_3O_8) or use of emission certificates
  - opportunity costs of (pumped-)storage power plants
  - near zero for most renewable generation units
  - negative for fossil units with binding technical constraints (must-run)
- Long –run marginal costs:
  - capacity expansion (capital costs) / building new power plants
  - capacity maintenance and repair / maintaining existing power plants

A market perspective on electricity II

Theory:

- A cost-minimal and CO_2-constrained system has a definite set of shadow-prices for electricity and CO_2 that leads to full cost-recovery of all market participants. (Holds only for the case of a linear cost function)
- Additional min/max capacity constraints for certain technologies raise the total costs of the system and lead to shortfalls or windfall profits.

Price components:

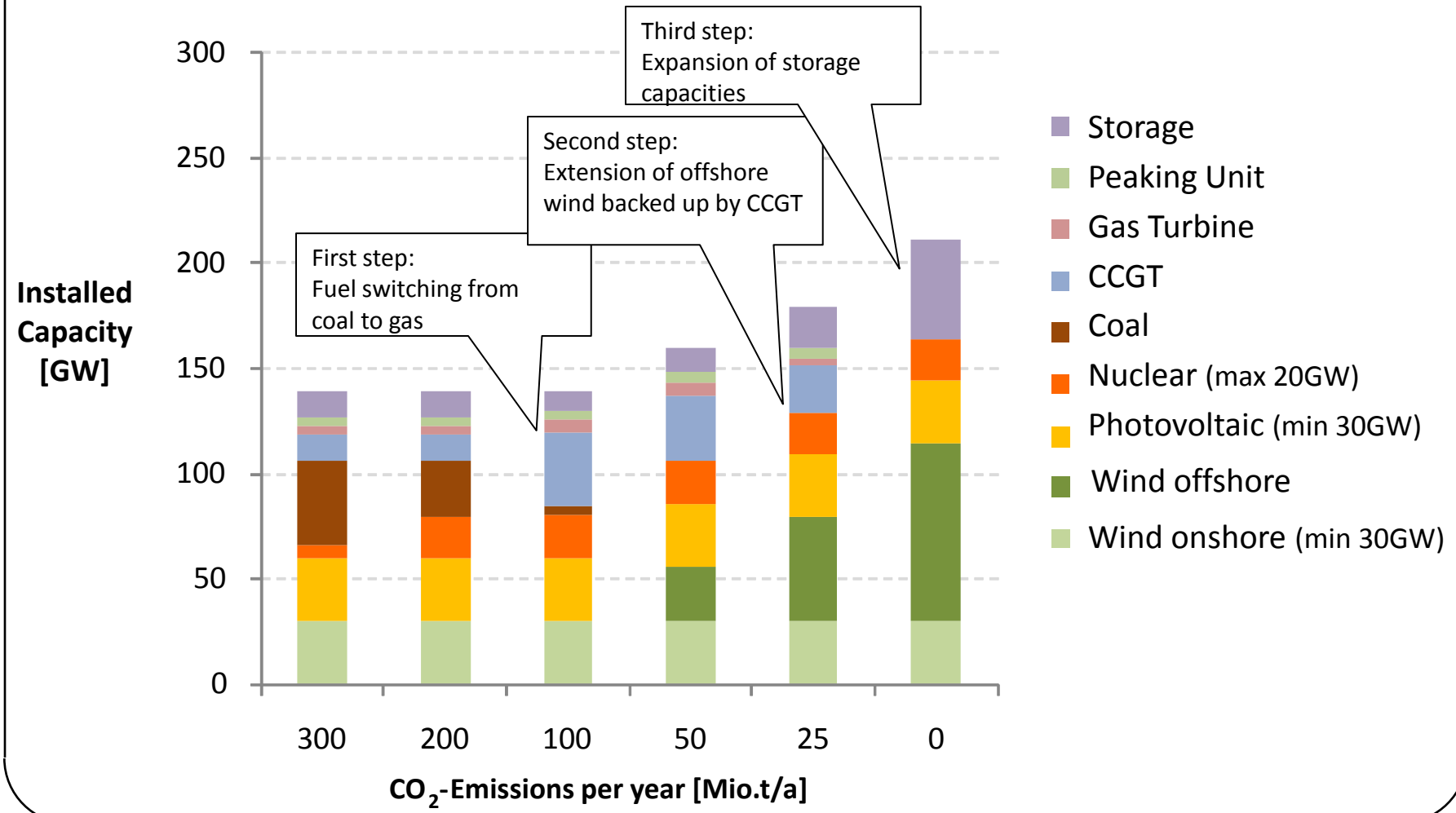
- Case 1 (Germany): No capacity markets:
  - One price for short-run marginal costs
  - Long-term costs can only be recovered while the system is either
    - not cost-minimal (expansion restrictions for nuclear power plants, lack of new market entrants) or
    - in the event of scarcity (Value of Lost Load Pricing)
- Case 2 (PJM): Capacity payments:
  - Long-term costs are recovered on the capacity market

Our market model

- Linear Optimization Model
  - Target Function: Minimize Costs!
    - Construction Costs
    - Fuel Costs
    - Costs for load gradients (to represent startup costs)
  - Subject to constraints:
    - Load-Serving (Renewables allowed to be curtailed)
    - CO_2-Emission Cap
    - Minimum uptime requirements (linear representation)
- Simulation Period 10/2008 – 10/2009
- Input data for Germany
  - Weather data – Wind/Solar/Temperature (very low wind activity during this period – worst case)
  - Real electricity demand data
  - Averaged commodity prices 2008-2010
  - Annualized capital costs for different technologies

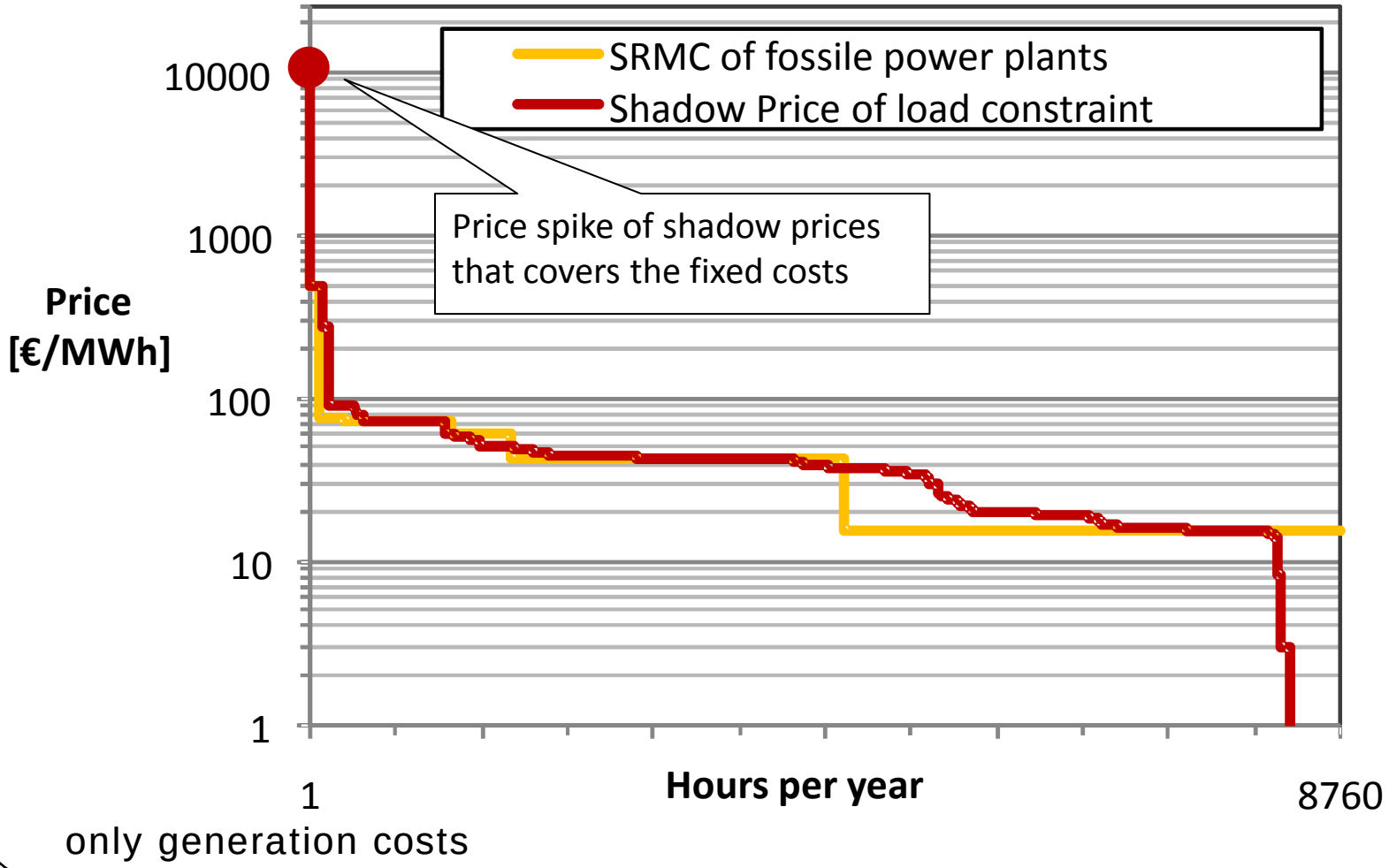
Scenario Results: The way to carbon-free generation

- Scenario including nuclear generation



Scenario Results: Price Duration Curves - BAU

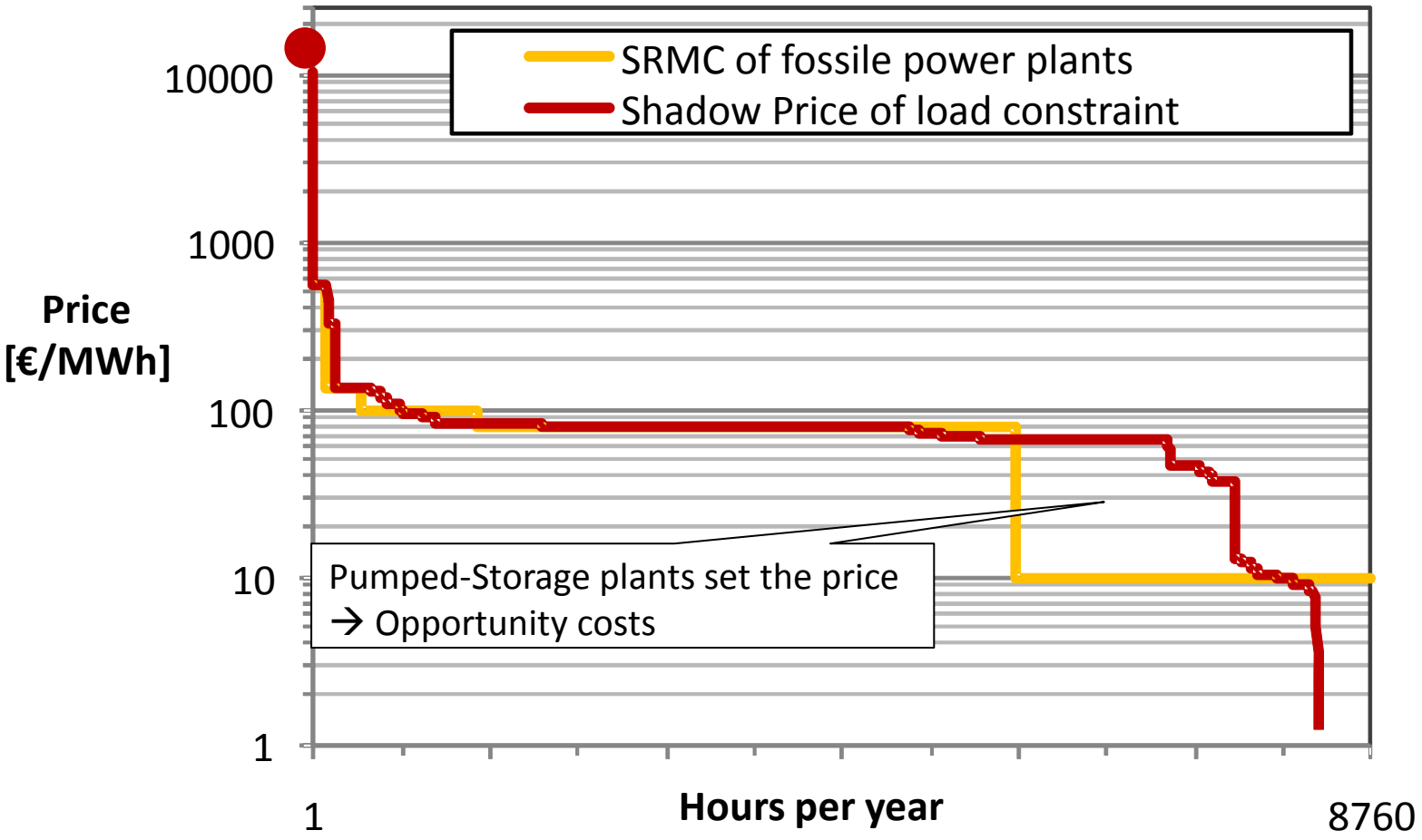
300 Mio.t CO2 (28 billion €/a)



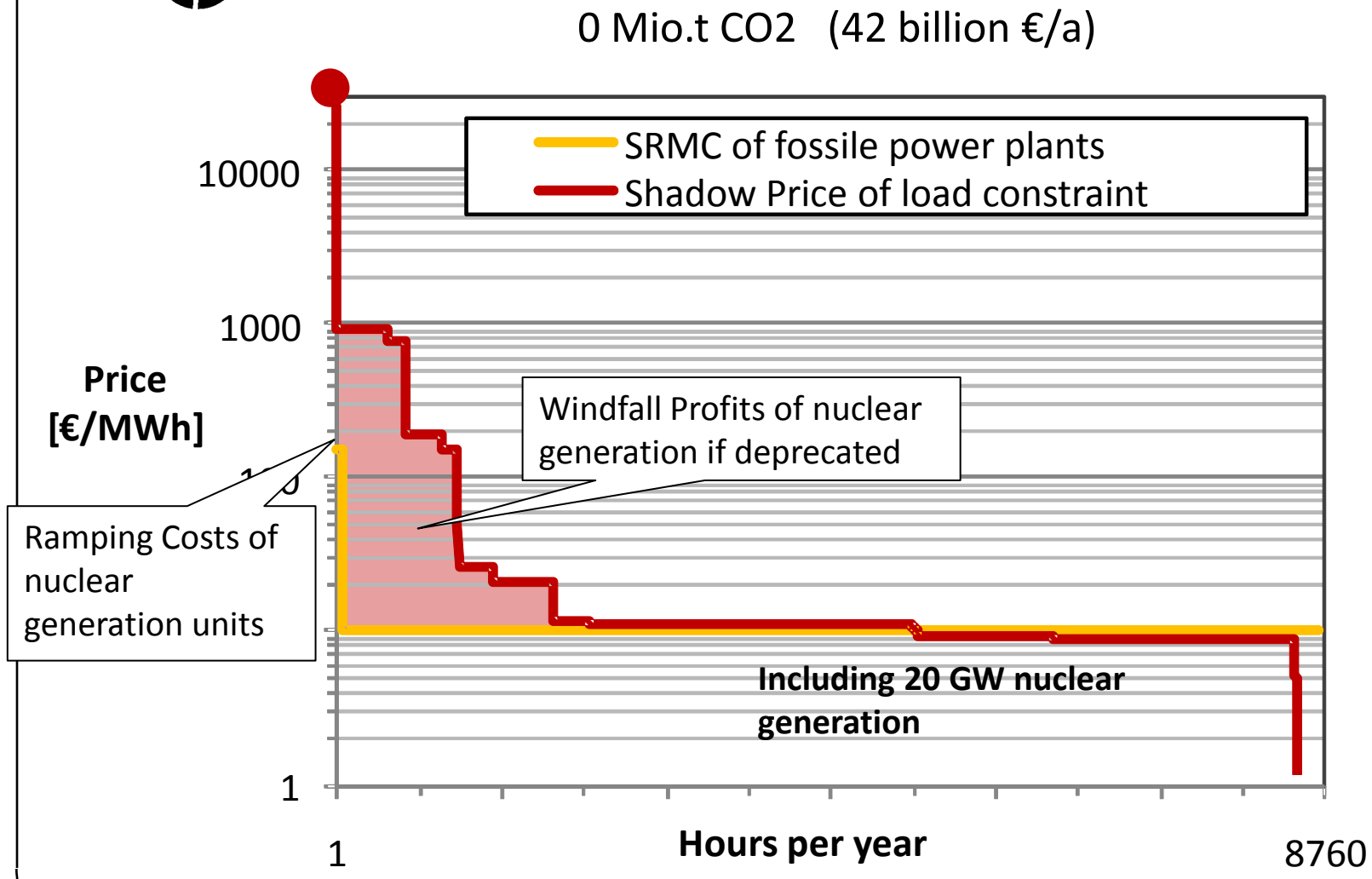
only generation costs

Scenario Results: Low Emission Scenario

25 Mio.t CO2 (34 billion €/a)



Scenario Results: Zero Emission Szenario



Scenario Results: Market results 50 Mio.t CO2/year (including 20 GW nuclear)

[Mio. Euro]	Total Marginal Costs (Shadow prices)	Short-Term Marginal Costs (Spot-Market)	Explanation
Onshore Wind	164,8	160,1	Losses
Offshore Wind	0,0	85,4	Losses
Photvoltaics	1.185,8	1.164,0	Losses
Nuclear Power	-5.089,7	-4.484,6	Profits
CCGT	0,0	1.205,9	Losses
Gas Turbine	0,0	293,0	Losses
Peaking Unit	0,0	49,7	Losses
Pumped-Hydro	0,0	359,8	Losses
CO_2 Market	-3.239,9	-3.239,9	Taxes
Customers	39.130,6	36.616,8	Sale rev ues
Market Results(Dual Solution)	32.151,6	32.210,0	
Costs (Primal Solution)	32.151,6	32.151,6	System c
Difference	0,0	58,4	

Fixed costs covered by price spike: 775 Mio. Euro

No opportunity costs of storage plants considered in spot prices!

In sum, revenues cover the total costs, but while **nuclear power plants generate huge profits**, fossil power plants and especially **renewables cannot recover their total costs with market prices based on SRMC.**

Scenario Results: Market results 50 Mio.t CO2/year (nuclear phase out)

[Mio. Euro]	Total Marginal Costs (Shadow prices)	Short-Term Marginal Costs (Spot-Market)	Explanation
Onshore Wind	**212,7**	**755,0**	**Losses**
Offshore Wind	**0,0**	**2.557,0**	**Losses**
Photvoltaics	**1.045,1**	**1.180,5**	**Losses**
Nuclear Power			
CCGT	**0,0**	**1.121,0**	**Losses**
Gas Turbine	**0,0**	**275,1**	**Losses**
Peaking Unit	**0,0**	**66,8**	**Losses**
Pumped-Hydro	**0,0**	**168,2**	**Losses**
CO_2	**-4.289,5**	**-4.289,5**	**Taxes**
Revenues Load Serving	40.553,1	35.839,7	**Sale revenues**
Sum (Dual)	37.521,4	37.673,8	
Costs (Primal)	-37.521,4	-37.521,4	**System costs**
Difference	0,0	152,3	

Fixed costs covered by price spike: 735 Mio. Euro

In this scenario, the **revenues do not cover the total costs** including CO_2.

Conclusions I

- Many market participants in Germany can incur losses in the future due to two effects:
  - **Change of the merit-order by subsidized market entries**
    - Not a problem of market design!
    - Just similar to changing demand.
    - Danger of sunk costs and stationary higher system costs.
  - **Losses due to pure SRMC-pricing**
    - Inherent to the market design
    - In the range of ~2-5% of the system costs
    - Can be reduced by the use of peak load DSM with low fixed costs
    - An enhanced operating reserves market might cover remaining costs
- Capacity payments might become necessary but less of the fact of wrong market design but more because the pace of installation of renewable resources highly exceeds regular investment cycles of fossil generation.

Thank you for your attention!

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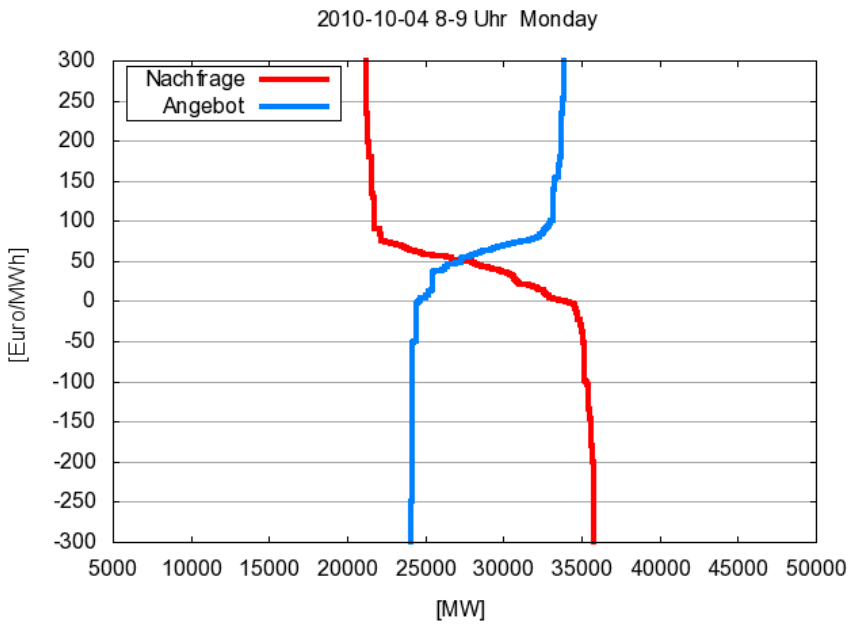
Additional conclusions from the model

- Non-market based deployment of renewable generation raises the system costs:
  - Onshore Wind: 2.000-5.000 €/MW/year
  - Photovoltaics: **50.000-100.000** €/MW/year

  without sunk costs of fossil power plants and costs for grid extension
- Curtailment of renewable resources is often preferable to storage.
- Pumped-storage power plants will become increasingly price-setting and market power mitigation will be more difficult
- To avoid negative external effects, a more coordinated dispatch of storage plants (one that is not only based on price forecasts) might become necessary

Rational Bids of Market Participants

- Rational bids at the day-ahead market:
  - free market: = marginal costs of production
  - feed-in tariff (active) < minus feed-in tariff
  - feed-in tariff (passive) = -infinity, only bounded by market restrictions:
    EPEX: -3000 €/MWh
    Regulator: -350 to -150 €/MWh



Results: Shadow Prices for Load Serving