A two-stages Day-Ahead Market design to decouple electricity prices from soaring natural gas prices

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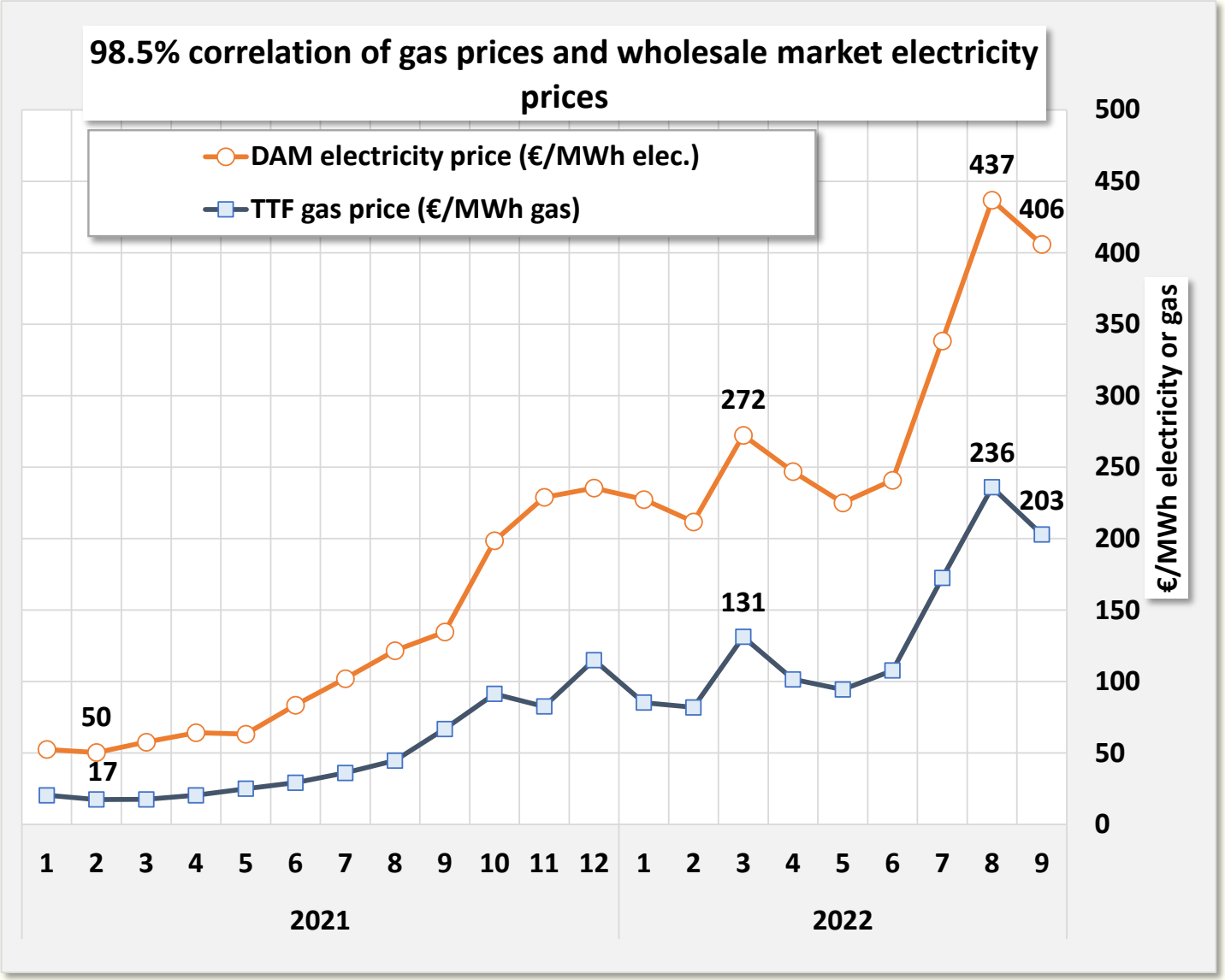


Unprecedented energy price crisis

- Compared to prices at the beginning of 2021:
  - Natural gas x 10
  - Wholesale electricity prices x 8
  - Retail electricity prices, depending on the share of fixed price contracts
- Wholesale electricity prices strongly dependent on natural gas prices
  - Natural gas, needed to balance other sources, is systematically the wholesale market price setter
  - But less than 1/3 of electricity comes from natural gas

Alternative ways of decoupling DAM electricity prices from natural gas prices

Options for immediate state intervention

- No state intervention, but only subsidies to vulnerable consumers
- Price cap on natural gas used in power generation (as in the Iberian case)
- Price cap on the DAM market clearing price and apply a pay-as-bid rule for more expensive power generation (so-called shock absorber mechanism)
- Revenue cap in the settlement of the DAM, and collection of the windfall profits (as in Greece and the European Commission's proposal) to return to the customers

Options for a permanent design

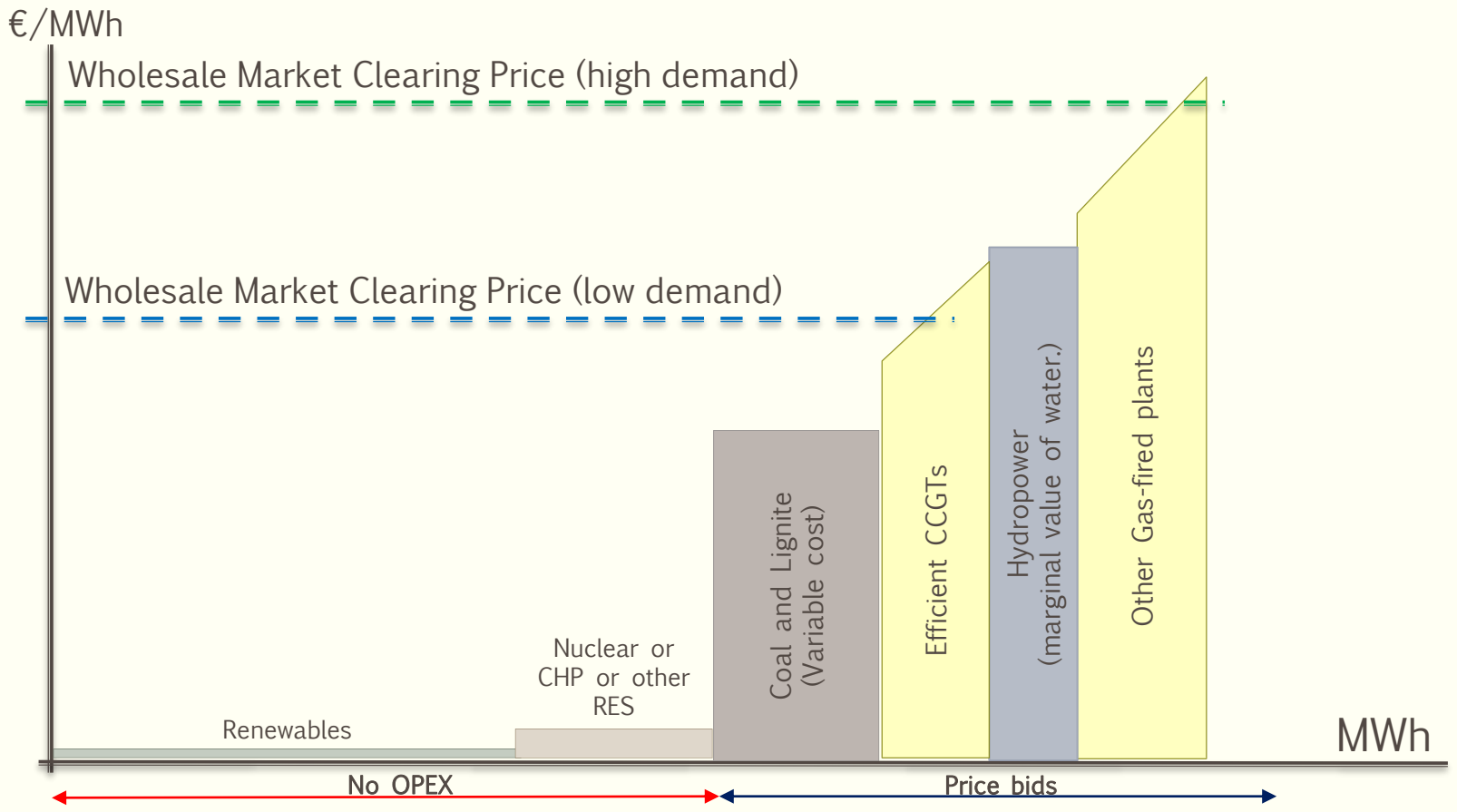
- No change
- Two-stages DAM, first the "As Available" and then the "On demand" generation resources
- Two-stages DAM with a mandatory pool for Renewables
- Split of the DAM in two markets, CAPEX and OPEX, with buyers addressing distinct demand to the two markets
- No split of the DAM, more incentives or even regulatory obligations for bilateral contracts

A typical supply function based on price bids in the Day Ahead Market

- Marginal cost pricing rule for the wholesale market
  - Pay as bid is not applicable
- Natural gas is the price setter more often than its share in the generation mix
- Poor demand response and low storage
- Large proportion of resources with total cost (CAPEX+fixed+variable) significantly below market clearing prices

- Assume that all suppliers buy from the DAM at marginal system costs (market clearing price)
- If the natural gas price is high, then
  - Costs of supply =
    Market Price x Consumption

    >> (higher than)
  - Total true costs =
    Sum over all plants of
    - Capital costs
    - Fixed costs
    - Fuel and emission costs



Public intervention: Revenue caps per technology

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  - Pay as bid is not applicable
- Natural gas is the price setter more often than its share in the generation mix
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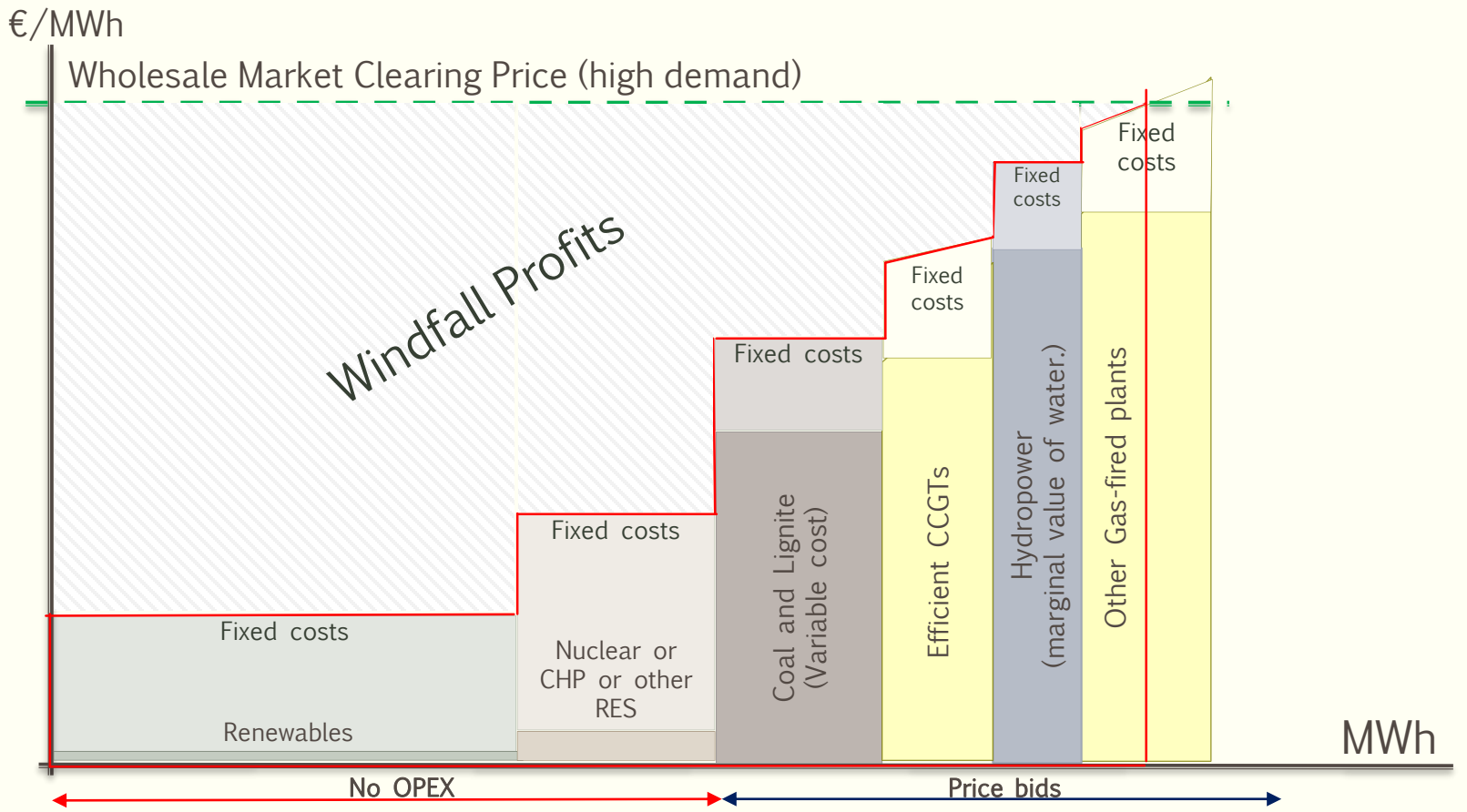
- If the natural gas price is high, then
  - **Costs of supply =**
    Market Price x Consumption
    >> (higher than)
  - **Total true costs (red polygon)=**
    Sum over all plants of
    - Capital costs
    - Fixed costs
    - Fuel and emission costs

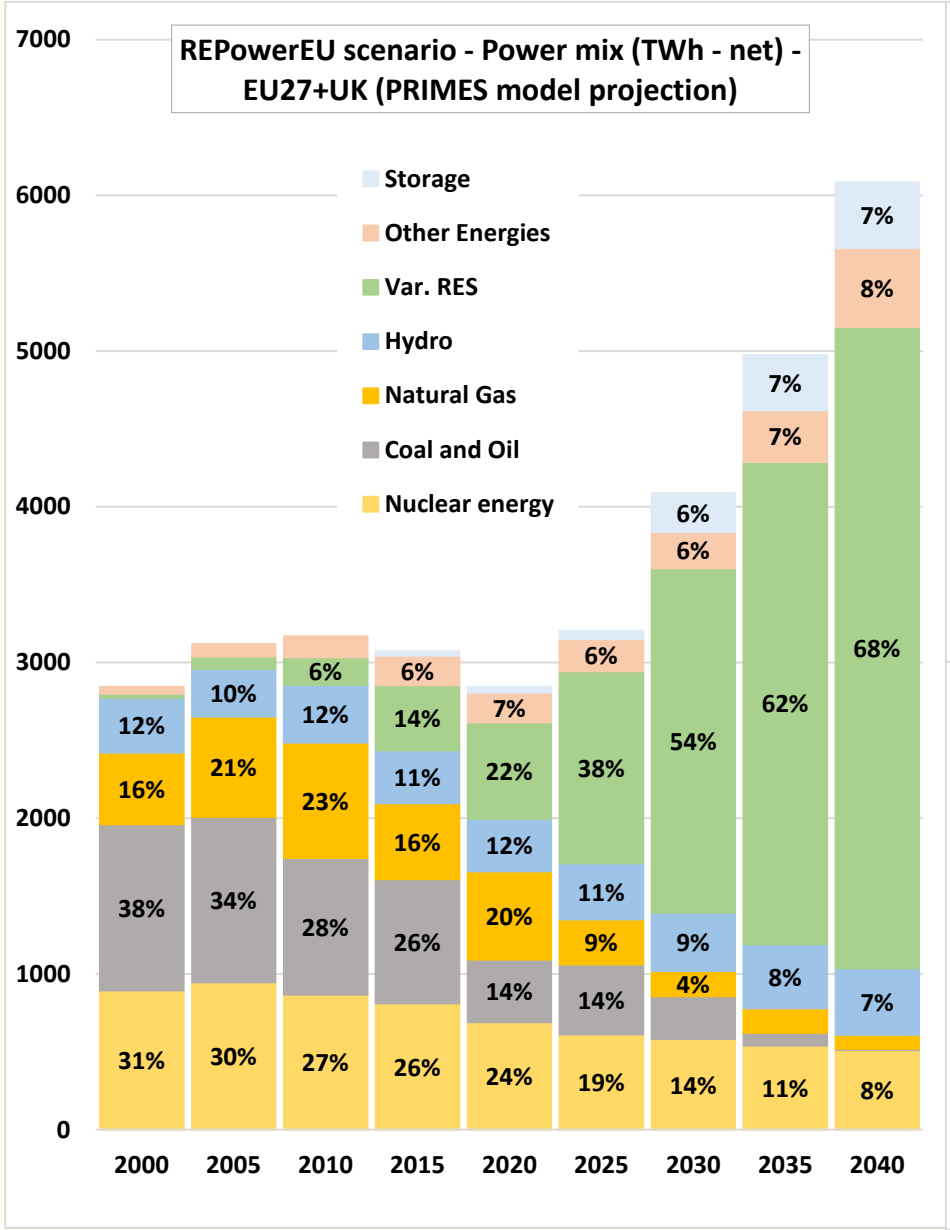
- Revenue caps per technology
  - Recover all costs
  - Avoid the windfall profits

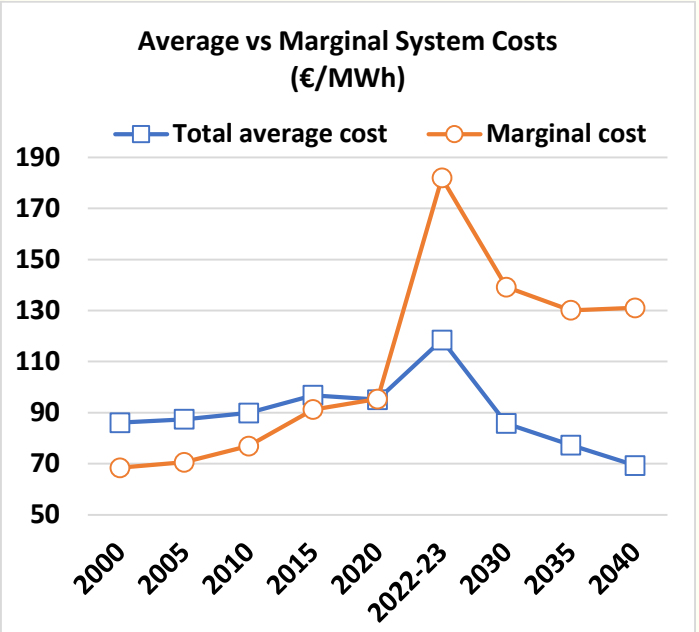


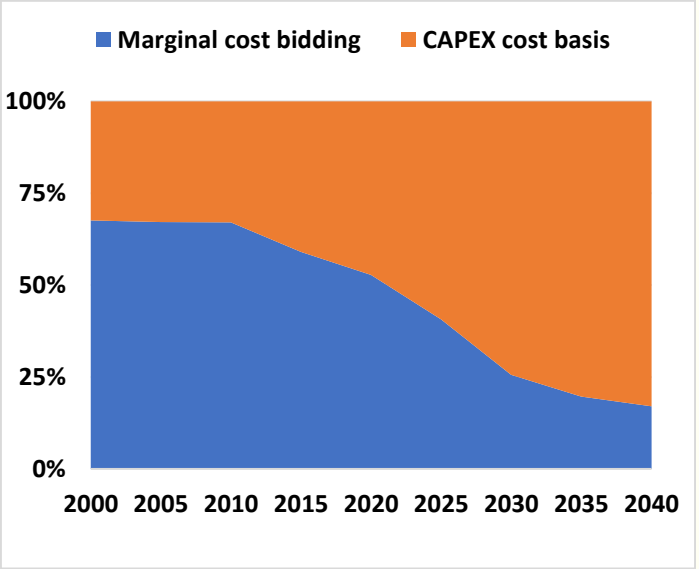
Net-zero carbon transition

(REPowerEU projection)

- The power mix drastically restructures away from fossil fuels
- The system's cost structure shifts from OPEX to CAPEX
- The marginal cost bidding resources have a diminishing share, below 25% already by 2030
- The CAPEX-depending resources need long-term contracts to get affordable capital financing
- The gas price crisis brought earlier than expected the situation where marginal system costs are systematically higher than total average costs; this is likely to perpetuate in the future within the green transition.
- (the opposite was occurring in the past)







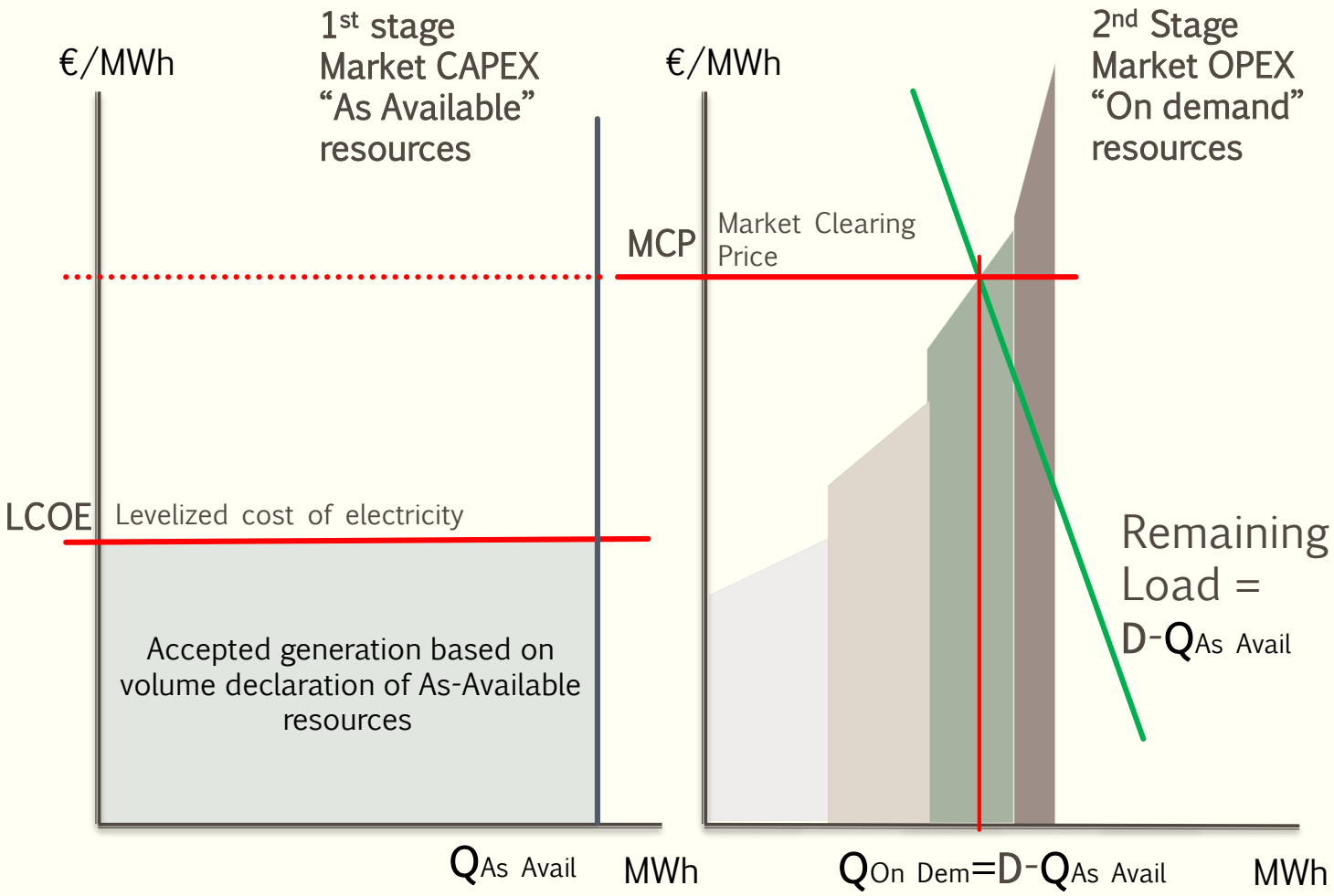
Therefore, we need to redesign the day-ahead market to achieve a decoupling of electricity prices from natural gas prices

Principles to respect:

- Maintain market competition
- Do not weaken price signals enabling demand response
- Achieve optimal market coupling and cross border flows
- Ensure adequate financing conditions to new investment adapted to the structure of costs to recover
- Encourage long-term bilateral contracting to induce market stability

- "As Available" power resources
  - Have the interest to enter in a schedule for the next day that respects as close as possible their planned generation volumes
  - Have no or insignificant variable costs and do not need to submit marginal cost bidding to be placed in the merit-order
  - Need to recover capital and fixed costs according to a stable long-term program to raise affordable capital financing
  - Examples: stochastic renewables, nuclear energy, mandatory hydropower, biomass, cogeneration of high efficiency serving heat demand, storage associated with specific plants
- "On demand" power resources
  - Typically the dispatchable generation resources, having the technical possibility to increase or decrease power depending on system operation requirements
  - Their marginal cost bidding (or opportunity cost bidding for some of them) induce the optimal merit-order
  - Examples: fossil fuel fired power plants, hydropower with a dam, storage plants, demand response, hydrogen

The Two-Stages Day-Ahead Market idea



- Buyers of electricity pay a weighted average unit cost ($WAUC$)

$$P = WAUC =$$

$$LCOE \cdot \frac{Q_{As\_Avail}}{Q_{As\_Avail} + Q_{On\_Dem}} + MCP \cdot \frac{Q_{As\_Dem}}{Q_{As\_Avail} + Q_{On\_Dem}}$$

- $LCOE$ is a weighted sum of different levelized costs of electricity of the various CAPEX-depending resources
- MCP is the market clearing price
- After the DAM, the market (balancing, reserves, complementary energy etc.) is unified again

How the two-stages Day-Ahead market operates

First stage: the “As Available” market

- The “As Available” resources submit volume declarations for the next day
- Submissions are per bidding zone
- Least-cost optimization over the coupled countries determines
  - The accepted volumes per “As Available” resource
  - The cross-border flows
- Objective to minimize: curtailment costs
- Constraints:
  - Net transfer capacities of interconnectors
  - Load to meet
  - TSOs’ constraints regarding dispatching possibilities

Second stage: the “On demand” market

- The “On Demand” resources submit price-volume bids, as today
- Demand response also submits bids
- Least-cost optimization over the coupled markets (as EUPHEMIA)
- Objective to minimize: social surplus (sum of producer and consumer surplus)
- Constraints:
  - Load to meet: Initial Load minus production by “As Available” resources
  - Net transfer capacities constraint: Initial NTCs minus cross-border flows based on “As Available” resources

Further explanations

Three options for the "As Available" market

- **A. Bilateral contracts** – over the counter and any possible form, e.g., long-term PPAs. The off-takers conclude contracts on a bilateral basis independently of the spot markets, so they know the volumes covered by the PPAs
- **B. Organised market for "As Available" resources:** the resources submit volume and price bids (equal ot above LCOEs) and get revenues at the "As Available" market clearing price. To mitigate market power a price cap on the "As Available" market is necessary.
- **C. Mixed design:** Mainly bilateral contracts as in A, but also a last-resort organized market as in B to accommodate resources lacking bilateral contracts.

"On demand" market

- No changes, the settlement is based on market clearing prices
- Also Intra-Day and Balancing markets remain unchanged
- Market coupling
  - It can be shown that the two-stages market approach leads to the same merit order and same cross-border flows as the single-stage market
  - In a similar way, in the two designs, interconnection congestion implies price divergence in the coupled markets