Energy System Modelling
Summer Semester 2019, Lecture 10

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14th June 2019

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Cost recovery in optimised system

Cost recovery in an optimised system

In this part of the lecture we will demonstrate that all players in the power network (generators and network operators) recover their costs, at least in theory with perfect markets in equilibrium.

We will discuss at the end why this does not work in practice.

Single node with optimised capacities and dispatch

Suppose we have generators labelled by s at a single node with **marginal costs** o_s arising from each unit of production $g_{s,t}$ and **capital costs** c_s that arise from fixed costs regardless of the rate of production (such as the investment in building capacity G_s). For a variety of demand values d_t in representative situation t we optimise the total system costs

$$\min_{\{g_{s,t}\},\{G_s\}} \left[\sum_s c_s G_s + \sum_{s,t} o_s g_{s,t} \right]$$

such that

$$\begin{aligned} \sum_s g_{s,t} = d_t \qquad & \leftrightarrow \qquad \lambda_t \\ -g_{s,t} \leq 0 \qquad & \leftrightarrow \qquad \underline{\mu}_{s,t} \\ g_{s,t} - G_s \leq 0 \qquad & \leftrightarrow \qquad \bar{\mu}_{s,t} \end{aligned}$$

We will now show using KKT that every generator exactly recovers their costs if the market price is set by λ_t^* ('no profit rule').

Single node with optimised capacities and dispatch

Take the costs of generator s at the optimal point:

$$c_s G_s^* + \sum_t o_s g_{s,t}^*$$

Use stationarity for $g_{s,t}^*$

$$0 = \frac{\partial \mathcal{L}}{\partial g_{s,t}} = o_s - \lambda_t^* - \bar{\mu}_{s,t}^* + \underline{\mu}_{s,t}^*$$

to substitute for o_s in the costs:

$$c_s G_s^* + o_s \sum_t g_{s,t}^* = c_s G_s^* + \sum_t (\lambda_t^* + \bar{\mu}_{s,t}^* - \underline{\mu}_{s,t}^*) g_{s,t}^*$$

Single node with optimised capacities and dispatch

Next use complementarity

$$\bar{\mu}^*_{s,t}(g^*_{s,t} - G^*_s) = 0$$
$$\underline{\mu}^*_{s,t} g^*_{s,t} = 0$$

to substitute for the terms $\mu^* g^*_{s,t}$

$$\begin{aligned} c_s G^*_s + o_s \sum_t g^*_{s,t} &= c_s G^*_s + \sum_t (\lambda^*_t + \bar{\mu}^*_{s,t} - \underline{\mu}^*_{s,t}) g^*_{s,t} \\ &= c_s G^*_s + \sum_t \lambda^*_t g^*_{s,t} + \sum_t \bar{\mu}^*_{s,t} G^*_s \end{aligned}$$

Finally use stationarity for the capacity G^*_s

$$0 = \frac{\partial \mathcal{L}}{\partial G_s} = c_s + \sum_t \bar{\mu}^*_{s,t}$$

to get full cost recovery from the market price:

$$c_s G^*_s + o_s \sum_t g^*_{s,t} = \sum_t \lambda^*_t g^*_{s,t}$$

Network of nodes with optimised capacities and dispatch

Suppose now we have a network of nodes i connected by lines ℓ.

Our investment problem is now:

$$\min_{\{g_{i,s,t}\},\{G_{i,s}\},f_{\ell,t},F_\ell} \left[\sum_{i,s} c_s G_{i,s} + \sum_{i,s,t} o_s g_{i,s,t} + \sum_{\ell} c_\ell F_\ell\right]$$

such that

$$\begin{aligned}
\sum_s g_{i,s,t} - \sum_\ell K_{i\ell} f_{\ell,t} = d_{i,t} \quad &\leftrightarrow \quad \lambda_{i,t} \\
-g_{i,s,t} \leq 0 \quad &\leftrightarrow \quad \underline{\mu}_{i,s,t} \\
g_{i,s,t} - G_{i,s} \leq 0 \quad &\leftrightarrow \quad \bar{\mu}_{i,s,t} \\
f_{\ell,t} - F_\ell \leq 0 \quad &\leftrightarrow \quad \bar{\mu}_{\ell,t} \\
-f_{\ell,t} - F_\ell \leq 0 \quad &\leftrightarrow \quad \underline{\mu}_{\ell,t}
\end{aligned}$$

Network of nodes with optimised capacities and dispatch

The cost recovery of the generators follows through exactly as before.

What about the costs $c_\ell F^*_\ell$ of each transmission line?

Use stationarity for the capacity F^*_ℓ:

$$0 = \frac{\partial \mathcal{L}}{\partial F_\ell} = c_\ell + \sum_t \bar{\mu}^*_{\ell,t} + \sum_t \underline{\mu}^*_{\ell,t}$$

to get

$$c_\ell F^*_\ell = F^*_\ell \sum_t \left[\underline{\mu}^*_{\ell,t} + \bar{\mu}^*_{\ell,t} \right]$$

'At the optimal point, fixed costs equal the sum of marginal benefits of expanding the line at each time.'

Next use complementarity for the flows $\bar{\mu}^*_{\ell,t}(f^*_{\ell,t} - F^*_\ell) = 0$ and $\underline{\mu}^*_{\ell,t}(-f^*_{\ell,t} - F^*_\ell) = 0$ to get

$$c_\ell F^*_\ell = \sum_t \left[\bar{\mu}^*_{\ell,t} - \underline{\mu}^*_{\ell,t} \right] f^*_{\ell,t}$$

Network of nodes with optimised capacities and dispatch

Finally use stationarity for each $f^*_{\ell,t}$:

$$0 = \frac{\partial \mathcal{L}}{\partial f_{\ell,t}} = \sum_i \lambda^*_{i,t} K_{i\ell} - \bar{\mu}^*_{\ell,t} + \underline{\mu}^*_{\ell,t}$$

to substitute for the μ^*:

$$\begin{aligned} c_\ell F^*_\ell &= \sum_t \left[\bar{\mu}^*_{\ell,t} - \underline{\mu}^*_{\ell,t}\right] f^*_{\ell,t} \\ &= \sum_t \sum_i \lambda^*_{i,t} K_{i\ell} f^*_{\ell,t} \end{aligned}$$

$\sum_i \lambda^*_{i,t} K_{i\ell} f^*_{\ell,t}$ is nothing other than the **congestion rent** on line ℓ at time t, i.e. the flow $f^*_{\ell,t}$ multiplied by the price difference across the line $\sum_i \lambda^*_{i,t} K_{i\ell}$.

Adding a CO2 constraint for a single node

If we add a constraint on the total CO_2 emissions

$$\sum_{s,t} \frac{\varepsilon_s}{\eta_s} g_{s,t} \leq \mathrm{CAP} \leftrightarrow \mu_{CO2}$$

where ε_s are the specific CO_2 emissions of technology s per fuel thermal energy and η_s is the efficiency of the generator (i.e. the ratio between thermal energy and electrical energy). CAP could correspond to e.g. political targets for CO_2 reduction.

All that changes is stationarity for the generator

$$0 = \frac{\partial \mathcal{L}}{\partial g_{s,t}} = o_s - \lambda_t^* - \underline{\mu}_{s,t}^* + \bar{\mu}_{s,t}^* + \mu_{CO2}^* \frac{\varepsilon_s}{\eta_s}$$

and now for each generator cost recovery becomes

$$c_s G_s^* + o_s \sum_t g_{s,t}^* = \sum_t \lambda_t^* g_{s,t} - \mu_{CO2}^* \sum_t \frac{\varepsilon_s}{\eta_s} g_{s,t}^*$$

This shows nicely the duality for exchanging the CO2 constraint for a CO2 price $o_s \rightarrow o_s + \mu_{CO2}^* \frac{\varepsilon_s}{\eta_s}$.

Grit in the machine 1/2

Several factors make this theoretical picture quite different in reality:

- Generation investment is **lumpy** i.e. you can often only build power stations in e.g. 500 MW blocks, not in continuous chunks.
- Some older generators have **sunk costs**, i.e. costs which have been incurred once and cannot be recovered, which alters their behaviour (i.e. the f term is not evenly distributed across all hours)
- Returns on scale in building plant are not taken into account (we did everything linear)
- Site-specific concerns ignored (e.g. lignite might need to be near a mine and have limited capacity)
- Variability of production for wind/solar ignored
- There is considerable uncertainty given load/weather conditions during a year, which makes investment risky; economic downturns reduce electricity demand

Grit in the machine 2/2

Several factors make this theoretical picture quite different in reality:

- Fuel cost fluctuations, building delays which cost money
- Risks from third-parties: Changing costs of other generators, political risks (CO_2 taxes, Atomausstieg, subsidies for renewables, price caps)
- Political or administrative constraints on wholesale energy prices may prevent prices from rising high enough for long enough to justify generation investment ("Missing Money Problem")
- Lead-in time for planning and building, behaviour of others, boom-and-bust investment cycles resulting from periods of under- and over-investment in capacity
- Exercise of **market power**

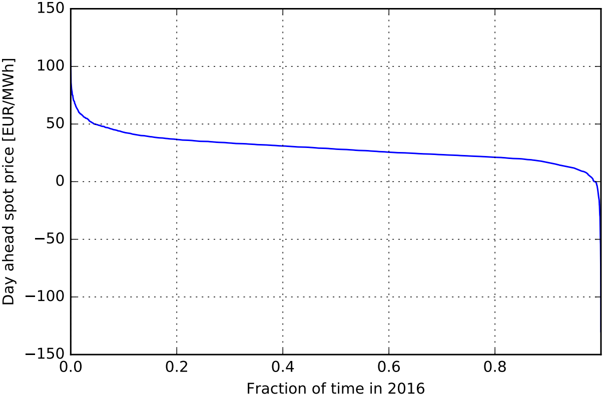
Episodes of High Prices are an Essential Part of an Energy-Only Market

In an energy-only market (in which generators are only compensated for the energy they produce), the wholesale spot price must at times be higher than the variable cost of the highest-variable-cost generating unit in the market. Episodes of high prices and/ or price spikes are not in themselves evidence of market power or evidence of market failure.

However, there may be political or administrative restrictions on prices going to very high levels (i.e. consumer protection, concerns about market abuse).

Today's market does not have episodes of very high prices

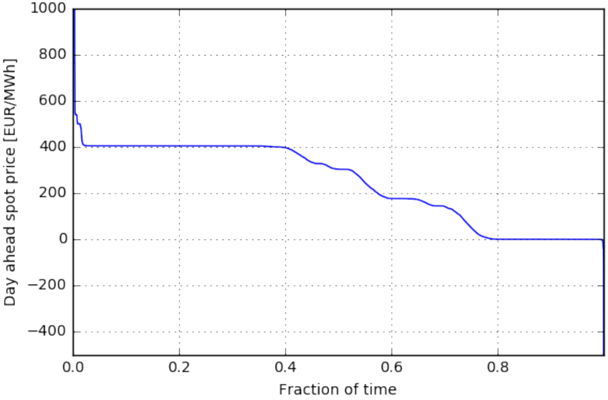
This makes it hard for e.g. gas generators to make back their costs. Day ahead spot market prices in 2016 in Germany-Austria bidding zone:



Gas generators can bid into other markets, such as the intra-day or reserve power markets, or provide redispatch services.

Market prices from FIAS highly renewable simulations

In our simulations for high renewable penetrations, the theory does however work:

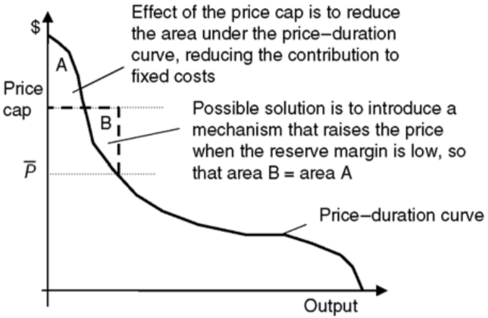


Prices are zero around a quarter of the time, but spike above 10,000 €/MWh in some hours.

Price cap

Some markets implement a maximum market price cap (MPC), which may be below the Value of Lost Load (VoLL) (V for the inelastic case).

In the Eastern Australian National Electricity Market (NEM), a MPC of A$13,800/MWh (€ 9,300/MWh) for the 2015-2016 financial year is set, corresponding to the price automatically triggered when AEMO directs network service providers to interrupt customer supply in order to keep supply and demand in the system in balance.

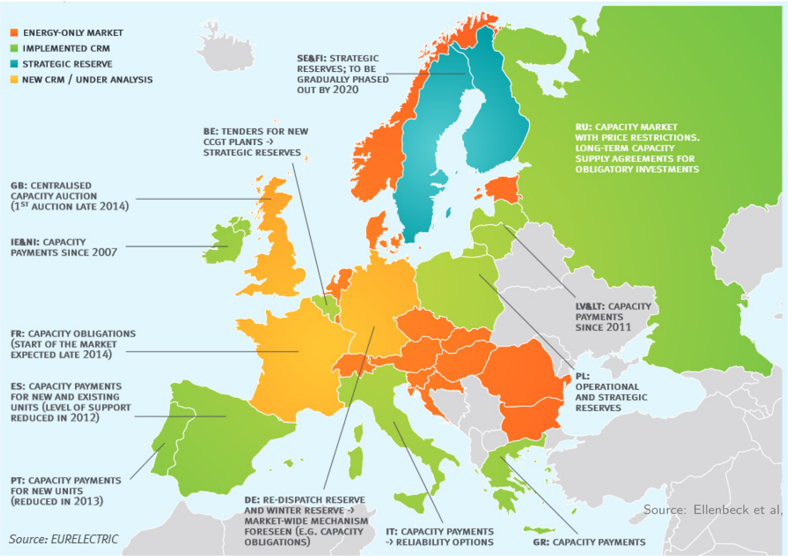


This can introduce distortions which make it difficult for some generators to recover costs.

Source: Biggar and Hesamzadeh, 2014

Europe: Capacity Markets in Some Countries

CRM = Capacity Remuneration Mechanisms (CRM): status June 2014



Source: Ellenbeck et al, 2014

Features of Transmission Investment 1/2

1. **Rationale for transmission**: Load and generation do not coincide in location at all times, so electricity must be transported for some of the time.

2. **Transmission is a natural monopoly**: Like railways or water provision, it is unlikely that a parallel electricity network would be built, given cost and limits on installing infrastructure due to space and public acceptance. Natural monopolies require **regulation**.

3. **Transmission is a capital-intensive business**: Transmitting electric power securely and efficiently over long distances requires large amounts of equipment (lines, transformers, etc.) which dominate costs compared to the operating costs of the grid. Making good investment decisions is thus the most important aspect of running a transmission company.

Features of Transmission Investment 2/2

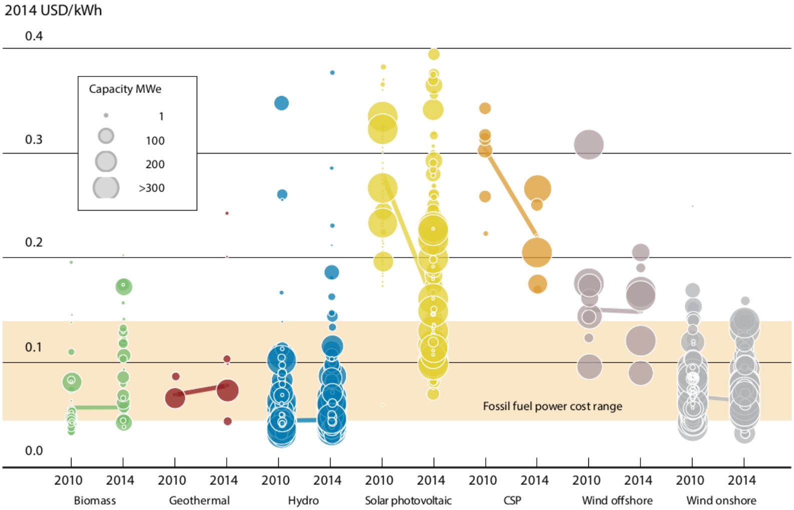
1. **Transmission assets have a long life**: Most transmission equipment is designed for an expected life ranging from 20 to 40 years or even longer (up to 60-80 years). A lot can change over this time, such as load behaviour and generation costs and composition.
2. **Transmission investments are irreversible**: Once a transmission line has been built, it cannot be redeployed in another location where it could be used more profitably.
3. **Transmission investments are lumpy**: Manufacturers sell transmission equipment in only a small number of standardized voltage and MVA ratings. It is therefore often not possible to build a transmission facility whose rating exactly matches the need.
4. **Economies of scale**: Transmission investment more proportional to length (costs of rights of way, terrain, towers, which dominate costs) than to power rating (which depends only on conductoring, which is cheap).

Integrating Renewables in Power Markets

Characteristics of Renewables

- **Variability**: Their production depends on weather (wind speeds for wind, insolation for solar and precipitation for hydroelectricity)
- **No Upwards Controllability**: Variable Renewable Energy (VRE) like wind and solar can only reduce their output; raising is hard
- **No Long-Term Forecastability**: Although short-term forecasting is improving steadily
- **Low Marginal Cost** (no fuel costs)
- **High Capital Cost**
- **No Direct Carbon Dioxide Emissions** (but some indirect ones from manufacturing)
- **Small unit size** (wind turbine is 2-3 MW; coal/nuclear is 1000 MW)
- **Somewhat Decentralised Distribution** for some VRE (e.g. solar panels on household rooves); offshore is however very centralised
- **Provision of system services**: Increasing

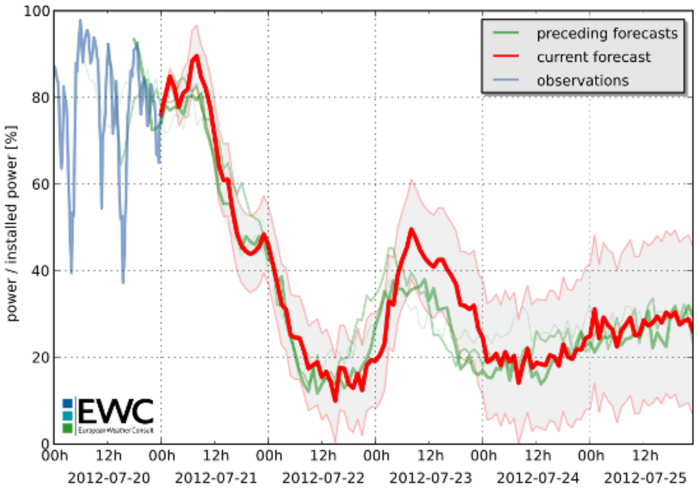
RE Levelised Cost already approaching fossil fuels



Source: IRENA Renewable Generation Costs

RE Forecasting

Just like the weather on which it depends, Variable RE (wind and solar) production can be forecast in advance. (Shaded area is the uncertainty.)



RE Forecasting

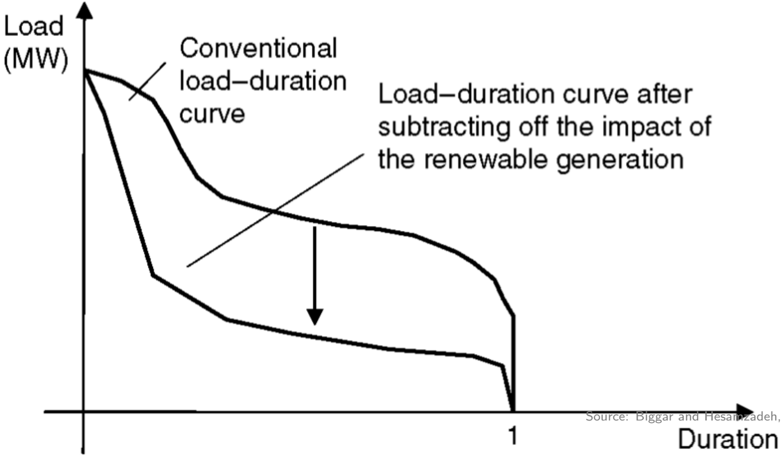
Like the weather, the forecast in the short-term (e.g. day ahead) is fairly reliable, particularly for wind, but for several days ahead it is less useful. In addition, it is subject to more uncertainty than the load. For example, fog and mist is very local, hard to predict, and has a big impact on solar power production.

This makes scheduling more challenging and has led to the introduction of more regular auctions in the intraday market.

Forecasting has also become a big business.

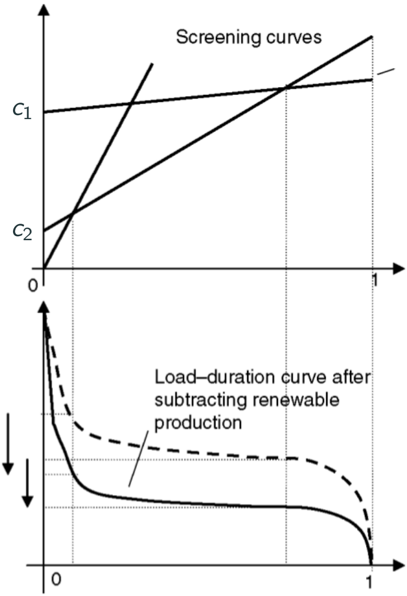
Effect on effective 'residual' load curve

Since RE often have priority feed-in (i.e. network operators are obliged to take their power), we often subtract the RE production from the load to get the **residual load**, plotted here as a demand-duration-curve.



Source: Biggar and Hesamzadeh, 2014

Residual load curve and screening curve



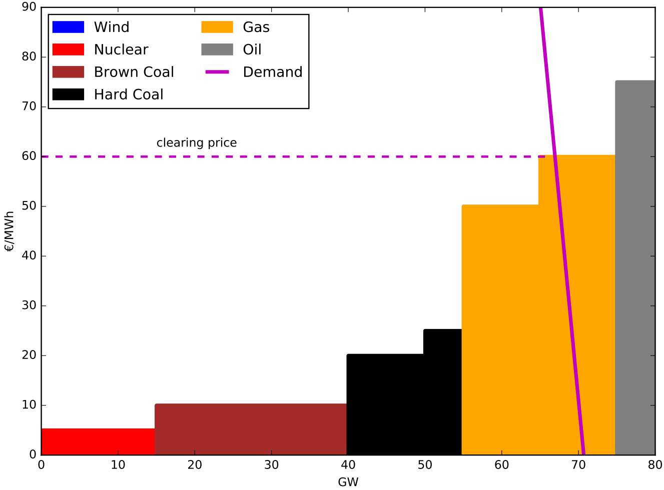
The residual load must be met by conventional generators.

The changed duration curve interacts differently with the screening curve, so that we may require less baseload generation and peaking plant and more load shedding, depending on the shape of the curve.

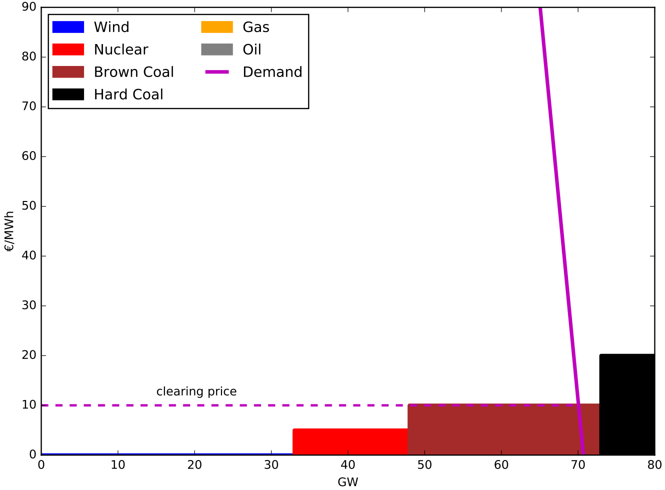
In some markets, there is increased demand for medium-peaking plant.

Source: Biggar and Hesamzadeh, 2014

Effect of varying renewables: fixed demand, no wind

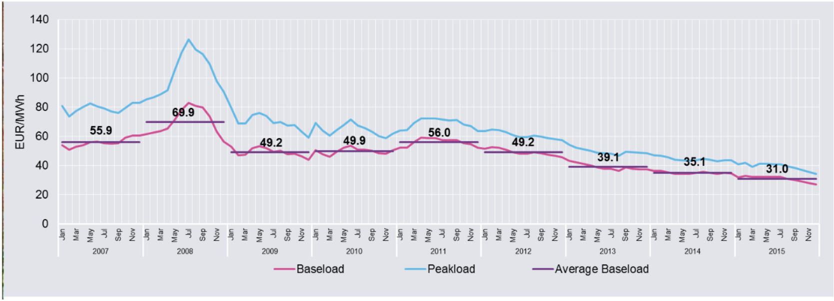


Effect of varying renewables: fixed demand, 35 GW wind



Spot market price development

As a result of so much zero-marginal-cost renewable feed-in, spot market prices steadily decreased until 2016 (but since went up again):



Source: Agora Energiewende

Merit Order Effect

To summarise:

- Renewables have zero marginal cost
- As a result they enter at the bottom of the merit order, reducing the price at which the market clears
- This pushes non-CHP gas and hard coal out of the market
- This is unfortunate, because among the fossil fuels, gas and hard coal are the most flexible and produce the *lowest* CO_2 per MWh
- It also massively reduces the profits that nuclear and brown coal make
- Will there be enough backup power plants for times with no wind/solar?

This has led to lots of political tension...

Market value

VRE have the property that they cannibalise their own market, by pushing down prices when lots of other VRE are producing.

We define the **market value** of a technology by the average market price it receives when it produces, i.e.

$$MV_s = \frac{\sum_t \lambda_t^* g_{s,t}}{\sum_t g_{s,t}}$$

We can compare this to the average market price, defined either as the simple average $\frac{1}{T}\sum_t \lambda_t^*$ or the demand-weighted average $\frac{\sum_t \lambda_t^* d_t}{\sum_t d_t}$.

Historic market values in Germany

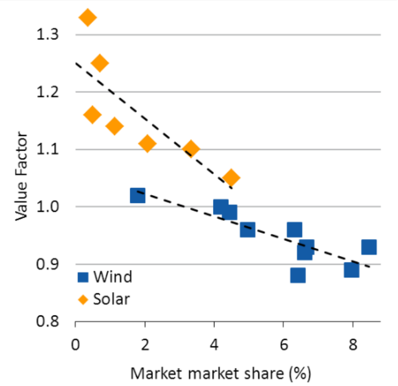


Figure 6. Historical wind and solar value factors in Germany (as reported numerically in Table 3).

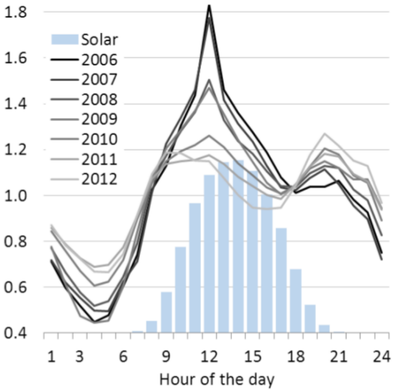
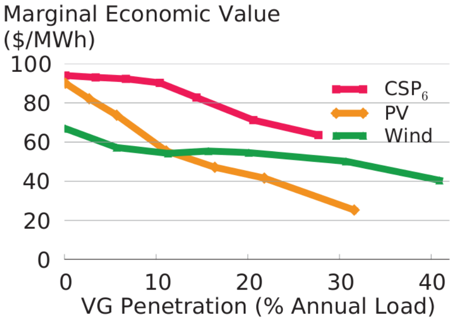


Figure 7. The daily price structure in Germany during summers from 2006 – 2012. The bars display the distribution of solar generation over the day.

Source: Lion Hirth, 2013

Market value at higher shares

At low shares of VRE the market value may be higher than the average market price (because for example, PV produces a midday when prices are higher than average), but as VRE share increases the market value goes down.

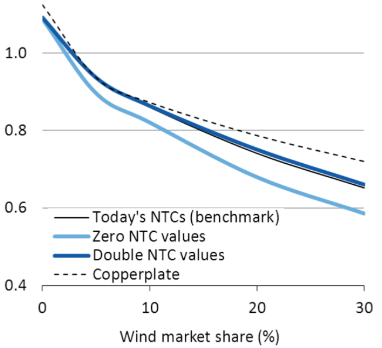


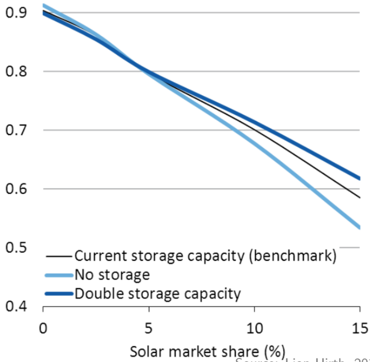
The effect is particularly severe for PV, since the production is highly correlated; for wind smoothing prevents a steeper drop off. The bigger the catchment area, the longer wind preserves its market value.

Source: Mills & Wiser, 2014

Market value mitigation

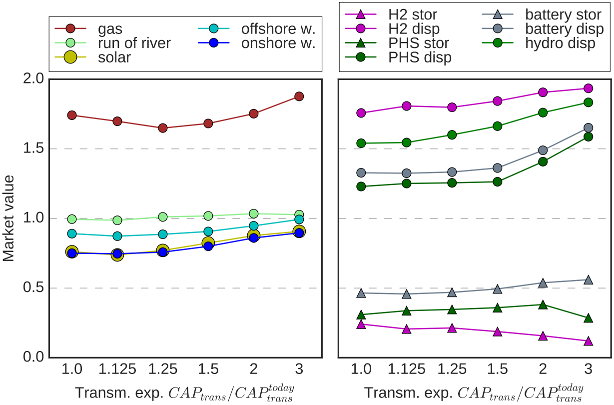
To halt the drop in market value (and hence revenue for wind and solar) we can use networks to do price arbitrage in space, storage to do arbitrage in time, or introduce CO2 prices that push up the prices in times when fossil fuel plants are running.





Source: Lion Hirth, 2013

Market value from our 95% renewable simulations



- Storage charges at low market prices and dispatches at high prices.
- Dispatchable power sources take advantage of high prices.
- Variable renewables get lower prices, but saved by storage, networks and high CO2 price.

Relation of LCOE to market value

From the first section we had for a perfect market in long-term equilibrium that all costs are recovered from market revenue:

$$c_s G_s^* + o_s \sum_t g_{s,t}^* = \sum_t \lambda_t^* g_{s,t}^*$$

If we divide both sides by the total yearly generation $\sum_t g_{s,t}^*$ then we get:

$$\frac{c_s G_s^* + o_s \sum_t g_{s,t}^*}{\sum_t g_{s,t}^*} = \frac{\sum_t \lambda_t^* g_{s,t}^*}{\sum_t g_{s,t}^*}$$

This is none other than the identity between the LCOE and market value:

$$LCOE = MV$$

This *only* holds in a perfect equilibrium. I.e. the equilibrium is found by increasing the penetration until the market value equals the LCOE.

In reality the market is far from equilibrium: subsidies support technologies (with a longer-term view of pushing them down the learning curve), there are sunk costs for existing plants, excess capacity supported outside the energy-only market, etc.