INTEGRATING LARGER SHARES OF INTERMITTENT RENEWABLES INTO THE ELECTRICITY SYSTEM: COMPETITIVE OR CENTRALLY PLANNED?

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Overview

Electricity generation from intermittent renewable energy sources (RES-E) like wind and photovoltaics (PV) has skyrocketed in recent years in the EU-27 with Germany leading, see Fig. 1. Moreover, they have started to change the usual pattern of electricity markets in Western Europe fundamentally. The fact that these "must run" capacities are offered at Zero or even negative costs over a large time per year has led to the situation that mainly natural gas power plants became economically less attractive because of lower fullload hours per year and to a call for "capacity" markets (CM) in addition to the "energy-only" markets. Currently, also the EC is looking for a new or revised electricity market design (Koch (2012)). In this paper the the future prospects for intermittent renewable resources for electricity generation in Europe are analyzed. The core objective is to investigate the likely effects of a further uptake of intermittent RES-E on the prices in electricity markets and on their integration into the grid. Another objective is to discuss the relevance and the effects of CM and the alternatives.

Method

Our method of approach is based on two basic principles: (i) the principle that crucial is the coverage of residual load with residual load being the difference between absolute load and generation provided by non-flexible electricity generation; in Fig. 2 the difference between the demand curve and the aggregated RES-E generation is the residual load; (ii) the principle that prices equal marginal costs. This principle prevails since the start of liberalization. Because at that time considerable excess capacities existed in Europe the expectation was that prices will (always) reflect short-term marginal costs (STMC). Because of lower fulload hours this principle is now questioned.

Results

One important issue is, how electricity prices will evolve in future if larger amounts of intermittent RES-E are generated. An example is shown in Fig. 2 where a hypothetical scenario with high levels of intermittent RES-E over a week in summer is depicted. The graph shows significant volatilities in electricity market prices with total costs charged for conventional capacities – black solid line – ranging from zero to 14 cents/kWh. In practice, of course, the prices may not just go to zero but also below. Given the price pattern in Fig. 1 we are convinced that it would be attractive for (some but sufficient) power plants operators to stay in the market or even to construct a very efficient new plant! This would lead to a revised energy-only market (EOM). If these temporaily high prices are not accepted capacity markets are needed.

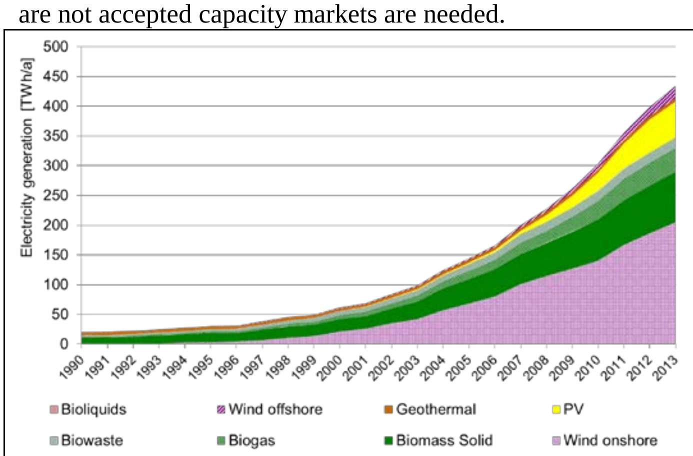


Figure 1. Development of RES-E electricity generation in EU-27 from 1990 to 2013 (Source: EUROSTAT, numbers for 2013 preliminary

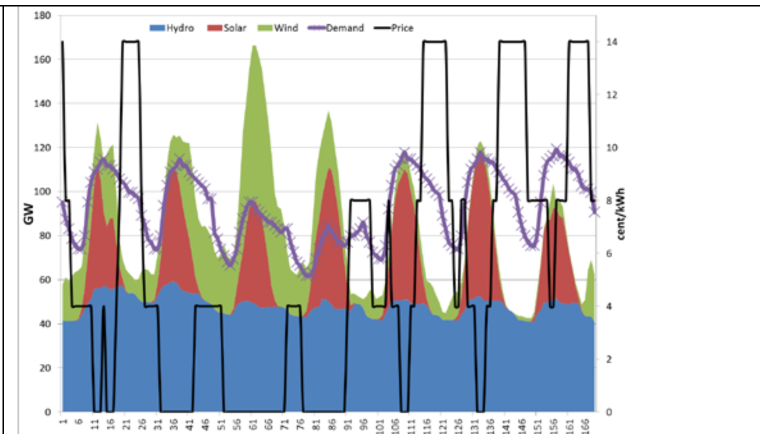
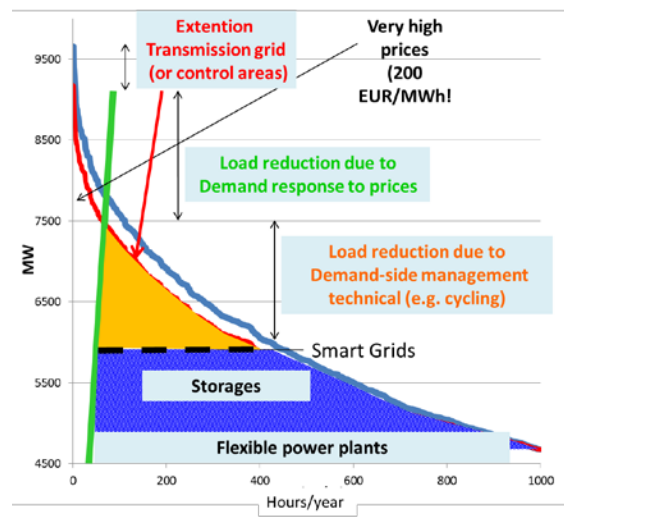


Figure 2. Development of intermittent RES-E over a week in comparison to demand and resulting electricity market prices with total costs charged for conventional capacities

The major CM models currently discussed are (see e.g. Cramton et al 2012): (i) a Comprehensive CM model which treats existing and new capacities jointly; (ii) a Focused CM approach which differs between existing and new capacities. In both of these market models – as in the classic EOM – the price should equal the STMC. The major open questions regarding CM are: (i) Which quantity of capacity should get payments and where? (ii) How to split in existing and new capacity? (iii) How to tune with grid extention?; (iv) Who plans? On national or international level?



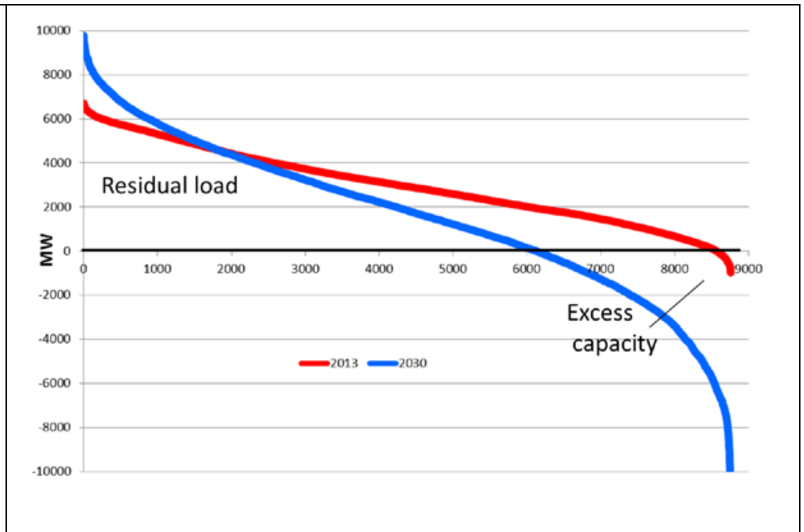


Figure 3. Options for coping with peak residual load in electricity markets	**Figure 4.** Development of residual load in Germany 2013 and in a scenario up to 2030 with high share of intermittent renewables

On contrary to this central planning approach a market-based one would take into account customers WTP and the equilibrium between demand and supply would come about at lower capacities. A market approach will consider also other options on the supply- and demand-side as there are, see Fig. 3:

- DSM (technical): Measures conducted by utilities like cycling, control of demand, e.g. of cooling systems)
- Demand response due to price signals: Response of mainly large customers to price changes
- Transmission grid extention: if the grid is extended there is in principle always more capacity available in the system and the volatility of RES a well as demand evens out;
- Smart grids: They allow variations in frequency (upwards and downwards regulation) and switch of voltage levels and contribute in this context to a load balancing
- Storages: short-term and long-term storages – batteries, hydro storages, or chemical storages like hydrogen or methane – can help to balance significant volatilities of RES generation.

An important aspect in this context is how the price spreads will develop. These price spreads will depend on the development of the duration curve of residual load. In Fig. 4 the development of residual load in Austria 2013 and in a scenario up to 2030 with a much higher share of intermittent renewables is described. The major perception of Fig. 3 is that the duration curve of the residual load profile will become steeper and that the number of hours with excess generation will become higher. This effect will lead straightforward to higher price spreads and will also increase

Hence, a major component of the revised EOM-model described above is to include all options for flexibility, especially demand-side contracts. In this category fits also the idea of Erdmann (2012) who suggests that the balancing groups should be responsible for providing capacities.

Conclusions

The major conclusion of our analysis is that capacity markets are a step back to a planned economy with – all in all – much higher costs for society. The only "negative" aspect of a market without capacity component will be that – at least in the short run – temporarily higher costs than the short-term marginal costs will occur. However, after some time the market will learn to benefit from these higher costs and also from the very low costs at times when RES are abundant. A reasonable price spread will come about that provides incentives for different market participants. Moreover, in addition to pure power generation capacities other elements like Smart grids, technical and economic DSM, short-term storage options will even out a large part of the residual load profile. Yet, the most important – so far neglected – issue for a real electricity *market* is the development of the demand-side.

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