

Resource Adequacy with Increasing Shares of Wind and Solar Power: A Comparison of European and U.S. Electricity Market Designs

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Abstract

We raise the question if improvements to current energy-only markets are sufficient to maintain resource adequacy in electricity markets or whether the rapid increase in wind and solar power gives stronger arguments for additional capacity mechanisms. A comparative analysis between Europe and the United States reveals some fundamental differences, but also many similarities in electricity market design on the two continents. We provide a list of general and specific recommendations for improved electricity markets and argue that lessons can and should be learned in both directions. The key to achieve a market-compatible integration of renewable energy is to focus on correct price formation in the short-term. Increased demand-side participation, improved pricing during scarcity conditions, and a transition from technology-specific subsidies of renewables towards adequate pricing of carbon emissions are important measures towards this end. In contrast, an increasing reliance on administrative capacity mechanisms would bring the industry back towards the centralized integrated resource planning that prevailed at the outset of electricity restructuring more than 25 years ago.

Keywords: Electricity Market Design, Resource Adequacy, Renewable Electricity Generation, Europe, United States, Price Formation, Energy-Only Markets, Capacity Mechanisms.

1 Introduction

At present, in many regions of the world electricity markets are confronted with major challenges. Among others, there is the important question of how to best maintain long-term resource adequacy in electricity generation and transmission systems with high shares of renewable electricity generation. The rapid growth in wind and solar generation, oftentimes supported by financial support schemes, tend to put downward pressure on wholesale electricity market prices thereby reducing incentives for new investments in generation assets. However, there have been a variety of additional drivers for the reduction in wholesale electricity prices in recent years, including decreasing natural gas prices, low electricity demand triggered by the financial crises in 2008, and low or missing carbon prices. Figure 1 and Figure 2 compare historical electricity and natural gas prices in Europe and the United States, respectively. In Europe, natural gas and most electricity market prices were generally increasing in the early 2000s. However, the relationship between prices for natural gas and electricity show less correlation after 2010, after which most of the growth in wind and solar resources occurred. Whereas electricity market prices have shown a downward trend since the peak in 2008, the price of natural gas has only shown a steep decrease in the last 3-4 years. The impact of natural gas prices on wholesale electricity markets in the United States appears more consistent (Figure 2), with a distinct reduction in both natural gas and electricity prices after 2008. The reduction in natural gas prices has been identified as the primary driver for low electricity prices in the United States in recent years (U.S. DOE 2017). We discuss the impacts of renewable energy on electricity prices in more detail in Section 2.2.

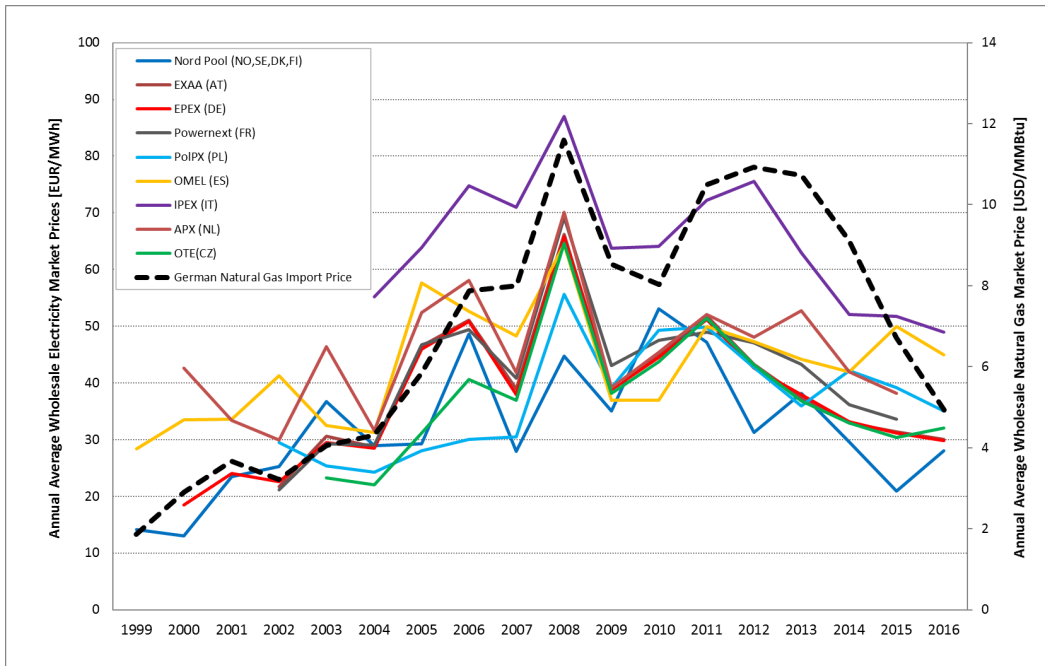


Figure 1 Comparison of annual average wholesale electricity market prices in Europe and wholesale natural gas price in Germany, 1999-2016. Sources: EEG-EEMD (2017) and BAFA (2017).

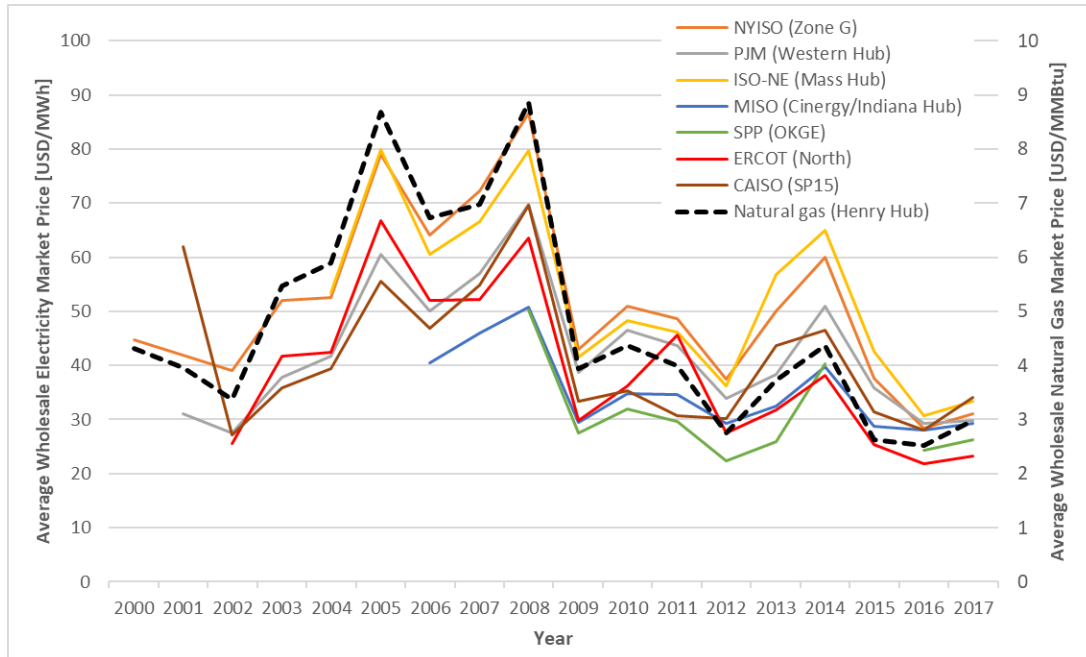


Figure 2 Comparison of average annual wholesale electricity market prices and natural gas market price in the United States, 2000-2017. Data Source: ABB Velocity Suite and U.S. EIA.

Prolonged low wholesale electricity market prices have resulted in increasingly visible profitability problems for electricity generators. Moreover, forecast errors of variable renewable electricity generation have increased the need for flexibility in the power grid, but the limited ability or willingness to dispatch down traditional base load generation technologies like nuclear and coal-fired power plants has imposed additional price and profitability risks on these resources. Because of these challenges, a comprehensive resource adequacy discussion has emerged in recent years both in Europe and the United States. The resource adequacy challenge is not a new problem, and many different policy options have been proposed and implemented to maintain resource adequacy in European and U.S. electricity markets. However, the rapid growth in renewable energy adds urgency to identifying robust market design solutions that provide revenue sufficiency for the portfolio of resources that are required to maintain system reliability. The overall objective of this paper, therefore, is to draw a comparative analysis between European and U.S. electricity markets with special consideration of resource adequacy incentives, while recognizing some fundamental differences but also many similarities in electricity market design on the two continents. In particular, the question is raised if improvements to current energy-only markets are sufficient to maintain resource adequacy as the shares of renewable electricity generation continues to grow or whether this change in generation portfolio gives stronger arguments for additional capacity mechanisms. In either case, a guiding principle is that the level of direct market interference should be kept to a minimum.

Although the literature is relatively limited, some studies compare electricity market design in Europe and the United States in general terms and look at different market elements in particular. For instance, Green (2008) addresses several important market design elements and outlines that the U.S. design is likely to give better results than the European models in a future with increasing shares of renewable generation in the systems. Haas et al (2008) compare the lessons learned from Europe, U.S. and Japan in terms of renewable support scheme design, with special consideration of triggering effects into new renewable generation capacities, and come to the conclusion that a stable regulatory framework is more important than the design details of the individual instruments. Imran and Kockar (2014) point out the overwhelming differences between European and U.S. electricity markets when comparing, besides general aspects, generation scheduling, transmission arrangement, as well as bid submission and processing in the wholesale market. In a recent paper, Pollitt and Anaya (2016) raise the question of whether current electricity markets can cope with high shares of renewables. Based on case studies of the electricity markets in Germany, the UK and the U.S. state of New York, they conclude that a new

round of electricity market experiments can be expected coping with large shares of renewables, but that it seems unlikely in the short run to lead to convergence in different approaches. Conejo and Sioshansi (2018) argue that it is necessary to re-think electricity market design due to the changing resource mix. Drawing on experiences primarily from the United States and Europe, they suggest important principles for future reforms of electricity market designs. The focus is primarily on short-term operations with limited attention to the longer-term resource adequacy challenge.

Our paper contributes to the existing literature by providing an updated review of incentive schemes for renewable energy and how these resources impact European and U.S. electricity markets. Moreover, we compare market design elements with particular relevance to resource adequacy, factoring in rules for short-term market operations and pricing as well as long-term capacity mechanisms and incentive schemes. Finally, based on our review of current markets, we discuss lessons to be learned across the two continents and provide recommendations for how to achieve more market-compatible integration of renewable energy into the respective electricity markets.

The rest of the paper is organized as follows: Section 2 compares the policies supporting renewable electricity generation in the Europe and the United States, as well as the impact of renewable generation on observed electricity market prices. Section 3 addresses and compares short-term electricity market operations in the two continents, whereas Section 4 elaborates on electricity market design for resource adequacy in the long-term. Sections 5 presents recommendations for improved electricity market design, split into common and regional specific areas of improvements. Section 6 concludes the paper.

2 Renewable Electricity Generation in European and U.S. Electricity Markets

The installed capacity of renewable energy technologies, in particular wind and solar PV, has increased rapidly in Europe and the United States in the last decade. At the end of 2015, the fraction of renewable energy generation in Europe, at 28.8%, was about twice as high as the one in the United States (Table 1). The vast majority of wind and solar energy was built after 2005 in both regions. However, hydropower was still the largest renewable generation resource in both places in 2015. Large-scale hydropower is an established generation technology, and most hydropower plants are fully dispatchable resources that do not impose the same short-term uncertainty and variability on the system as wind and solar resources, although there is long-term uncertainty in hydro resource availability.

Table 1 Renewable generation as percent of total electricity generation in United States and Europe (EU-28), 2005 and 2015. Sources: U.S. DOE (2016) and Eurostat (2017).

Technology	United States		Europe (EU-28)	
	2005	2015	2005	2015
Hydro	6.7	6.1	10.7	10.9
Wind	0.4	4.6	2.1	8.9
Solar	0	1.1	0.0	3.4
Biomass	1.3	1.6	1.4	2.8
Other	0.4	0.4	1.0	2.9
Total [%]	8.8	13.8	15.2	28.8
Total [TWh]	358.2	567.3	490.5	972.2

A large effort has been made in recent years to reduce technology costs and to establish electricity market designs supporting the integration of variable renewable electricity (VRE) resources, such as wind and solar energy, into the power grid. Already in an early stage of renewable technology development it was recognized that technology learning and innovation, technology cost reductions and thus accelerated market integration of these technologies can be supported by different financial and policy instruments, see e.g. Sawin (2004), Kobos et al (2006), Held et al (2006)). Recent publications (e.g. Held et al (2017)) support the argument that without these different instruments this rapid development of renewable energy technologies would not have been possible, notably in the last decade.

Recent studies indicate that wind power and solar photovoltaics (PV) recently almost reached cost competitiveness with traditional generation resources (e.g. Wiser and Bolinger 2017 (Wind), Fraunhofer-ISE 2017 and Jäger-Waldau 2016 (PV)). However, Held et al (2017) argue that it is too early to completely phase out financial support of the wind and PV technologies and cede them to the market forces only. Oftentimes, there are additional motivating factors beyond technology innovation behind support schemes for renewables. For instance, such schemes to some extent correct for externalities of carbon emissions, currently not appropriately priced in most electricity markets. The creation of local jobs is oftentimes also an important goal for supporting growth in sustainable renewable energy technologies. In this section, we briefly review the main incentives and support schemes that have contributed to the rapid growth in renewable energy in Europe and the United States.

2.1 Incentives for Integration of Renewable Electricity Generation

2.1.1 Direct Subsidy Schemes and Environmental Policies

In general, direct financial support schemes for renewable electricity generation can be divided into two main categories. *Price/cost-driven instruments* are usually technology-specific, either providing increased remuneration of electricity generation (e.g. feed-in tariffs) or compensating parts of the technology costs (investment grants, tax credits, etc.). *Quantity-driven instruments* usually define a quota where one or more renewable electricity generation technologies compete to meet the target (e.g. green certificates, renewable portfolio standards). The main instruments applied in Europe and United States are briefly described below.

Europe:

- **Green Certificates:** Renewable electricity generators receive certificates for their 'green' electricity produced, which they may sell to market participants (e.g. supply companies) obliged to fulfil a predefined renewable electricity quota. Selling certificates provides an additional income on top of the market price of the electricity sold. The main advantages of quota obligations with tradeable green certificates are the high compatibility with market principles and competitive price determination. However, high risk premiums arising for investors in renewable energy from the uncertainty in both electricity and certificate prices typically increase policy costs.
- **Feed-in Tariffs:** In a Feed-in Tariff (FIT) system, renewable electricity generators receive a fixed payment for each unit of electricity generated, independently from the wholesale electricity market price. Investors in renewable energy receive a stable remuneration from the FIT, which may be determined administratively or from an auction mechanism (see below). In practice, the basis for the calculation has mostly been the overall cost of a technology in terms of its Levelized Cost of Electricity (LCOE). FITs are usually technology-specific instruments.
- **Feed-in Premium:** In a Feed-in Premium (FIP) system, renewable electricity generators are obliged to sell the electricity generated directly to the wholesale electricity market. However, renewable generators receive an additional payment on top of the electricity market price, either as a fixed payment or adapted to changing electricity market prices (e.g. to reach the same total compensation rate as under a FIT). The FIP scheme limits both price risks for renewable electricity generators and the risk of providing them with windfall profits.
- **Tender/Auction Schemes:** Competitive bidding procedure used to allocate financial support to different renewables technologies and to determine the support level of direct support schemes, such as FITs. There are different ways to design an auction, e.g. with mitigation measures to ensure that winning bidders effectively implement their project (e.g. pre-qualification, penalties, etc.).

United States:

- **Renewable Portfolio Standards:** A Renewable Portfolio Standard (RPS) is basically the same instrument as green certificates. In the United States, a RPS is typically imposed by a state on its local utilities, which are then required to meet a certain fraction of their electricity demand from renewable resources. A market for Renewable Energy Credits (RECs) is usually created, where renewable energy producers can sell credits to utilities in need of meeting RPS requirements.

- **Renewable Portfolio Goals:** A Renewable Portfolio Goal (RPG) is similar to a RPS, but with the main difference that the RPG is a voluntary target rather than a mandatory requirement. RPGs are also implemented at the state level.
- **Production and Investment Tax Credits:** Tax credits are usually implemented at the federal level to create a financial incentive for investment in renewable energy, and could take the form of production or investment tax credits. For instance, a production tax credit (PTC) has been in place for wind power since the 1990s, which has expired and been extended on multiple occasions.

Figure 3 shows that in Europe price-driven support instruments have been prevailing in most countries, notably FITs and more recently FIPs. From the renewable generators' point-of-view, FITs/FIPs perfectly hedges the market price risk of renewable electricity generation and thus significantly contributed to the deployment of these technologies, notably in countries like Germany and Spain. The figure also reveals the recent trend of moving towards auctions for renewable generation technologies, as a means to achieve renewable targets and compensation levels in a more cost effective manner.

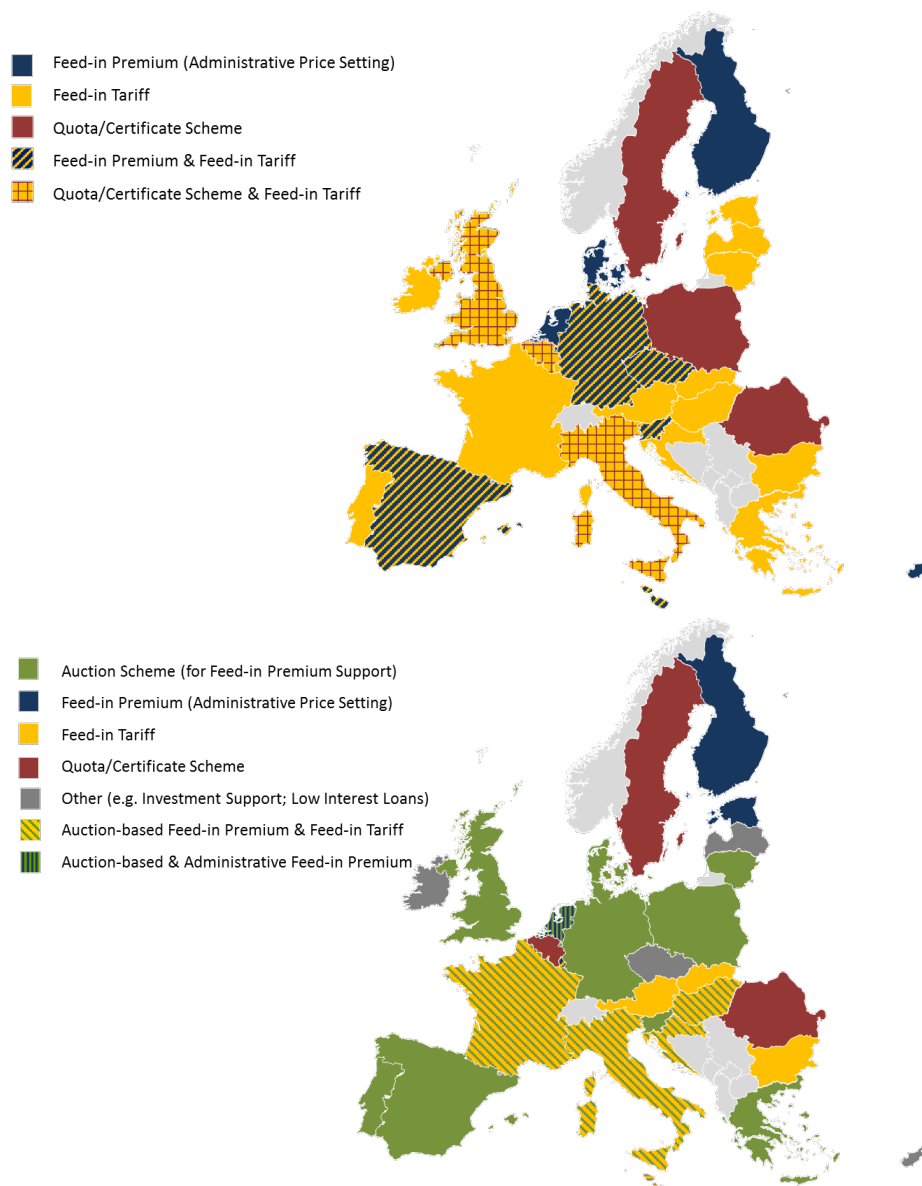


Figure 3 Different financial support instruments for renewable energy in Europe (EU-28) in 2012 (upper) and 2017 (lower). Source: EEG Green-X (2017).

In the United States, a major incentive mechanism for renewable generation technologies has been RPSs at the state level, with as many as 29 states having implemented RPSs and a few additional states relying on RPGs (Figure 4). Many states also have net metering rules, which also indirectly support distributed generation, as discussed in the next section. At the federal level, tax credits have been the major incentive scheme, with a PTC for wind power and an investment tax credit (ITC) for solar PV. However, these incentive schemes are gradually being phased out. The PTC for wind power is schedule to end after 2019. The ITC for solar will also be ramped down after 2019.

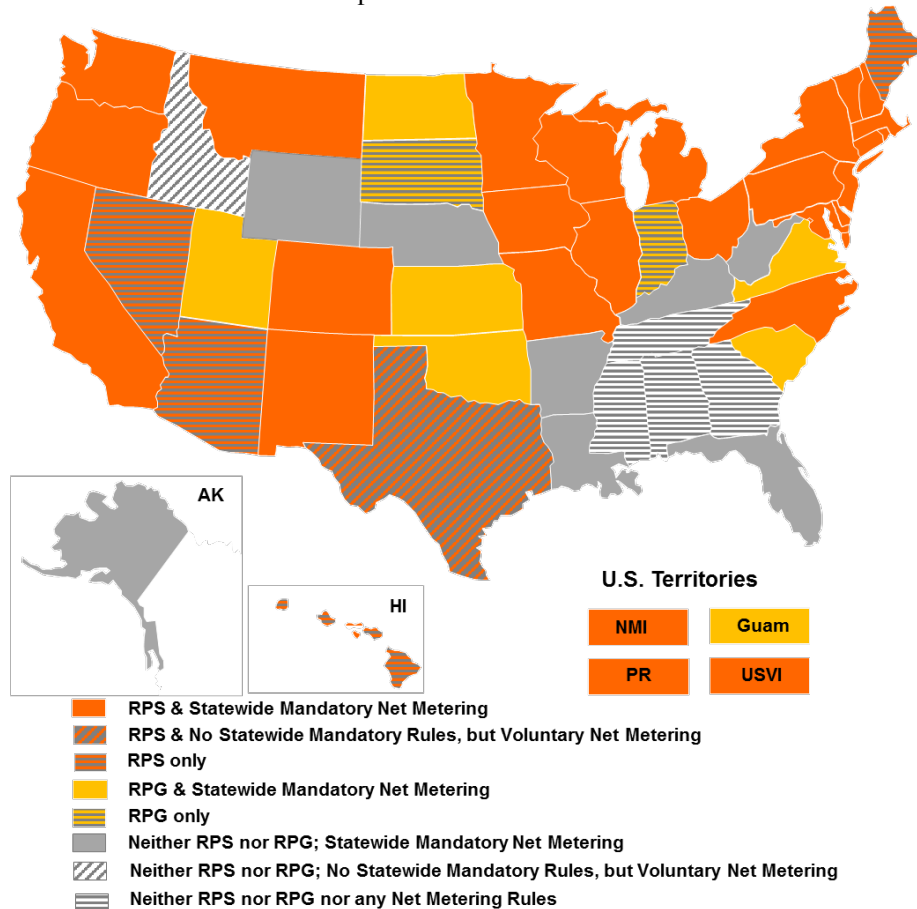


Figure 4 Different financial support instruments for renewable energy in U.S. states. Data source: DSIRE (2017).

Environmental policies are also important support schemes for renewable energy. For instance, climate change policies influence the incentives for investments in renewable energy generation. The European Emissions Trading System (ETS) adds a cost for CO₂ emissions from thermal generators, which favors other generation technologies like renewables without CO₂ emissions. In the United States, in the absence of a federal climate policy, two regional carbon emissions trading schemes have been introduced, i.e. in the Northeast and in California. A common trend for all of the carbon emissions trading schemes has been relatively low prices in recent years (see e.g. EEA (2017), EIA (2017)). Hence, their impacts on investments in renewable energy have likely been limited.

2.1.2 Indirect Enablers

In addition to the direct renewable support instruments and environmental policies discussed above, there are also other enablers of renewable energy investments. For instance, net metering rules are improving the economic viability of distributed generation and particularly solar PV. Under net metering, distributed generation is netted against the owner's consumption. Since electricity tariffs typically relies primarily on volumetric charges, not only to recover energy costs but also distribution,

transmission, and policy costs, net metering provides an indirect incentive to distributed resources that end up receiving a considerably higher compensation per unit of electricity generation than generation resources in front of the meter (MIT, 2016). Net metering can be implemented solely as an accounting procedure requiring no special metering or even any prior arrangement or notification, i.e. by simply measuring a consumer's net electricity consumption per month and bill accordingly. Still, with the large-scale roll-out of smart meters improved incentives could be achieved through more frequent meter reading combined with time varying rates. Net metering is currently used in the majority of U.S. states (Figure 4) and in several European countries.

Another indirect enabler of investments in distributed energy resources is the developing of local energy sharing approaches and microgrid solutions. For instance, in the United States, community solar projects (Coughlin et al. 2012) are gaining increasing interest among local communities (e.g. owners/residents of condominium or apartment buildings) that are looking for alternatives to large-scale conventional electricity generation. Moreover, the establishment of local energy communities is also one of the explicit policy goals within the European Union (EC, 2017) and for some individual countries, most notably in countries with ambitious upcoming renewable targets while also considering combined local energy storage technology implementation. Such energy sharing projects benefit from high retail electricity tariffs and also oftentimes from net metering rules, i.e. high variable shares of the retail tariffs favor onsite/local self-generation. In the upcoming years, we expect that the importance of such concepts for distributed generation and energy sharing at the local level, possibly combined with peer-to-peer trading, will continue to increase in Europe as well as in the United States, thereby contributing to the growth in renewable energy.

2.1.3 Voluntary Schemes

The general desire of moving towards cleaner electricity supply across different parts of society also manifests itself through mechanisms of a more voluntary nature. Increasingly, 'green' products and services are demanded by different customer groups (households, commercial and industrial sectors) willing to pay more compared to products and services based on electricity from a more traditional generation mix. This kind of customer segmentation is already established in different regions as well as for companies with a global reach. For instance, corporate renewables deals amounted to between 1GW and 3.5GW per year in the United States and Mexico since 2014 (BRC, 2017). This recent trend is led by large companies like Google, which reached its 100% renewables goal in 2017 (Google, 2016). In this context, it is also important to note, that 'green' products and services are increasingly being offered by various retailers (e.g. food retail chains, etc.), apart from the traditional energy sector (power, 2014). Another development at the local level in the United States is that counties and cities in several states have introduced so-called community choice aggregation programs, where local electricity consumers are automatically enrolled into an alternative retail contract that typically provide electricity from cleaner generation resources at a competitive price (Borenstein, 2016).

In sum, the combination of direct subsidies, environmental policies, indirect enablers, and voluntary schemes has provided substantial momentum to the growth in renewable energy capacity (Table 1).

2.2 Price Effects in the Wholesale Electricity Markets in Recent Years

Several factors have influenced the development of electricity prices in recent years, although the importance of various factors are different in the European and U.S. markets, as briefly discussed in section 1. In this section, we discuss the observed impacts of variable renewable electricity generation on short- and long-term wholesale electricity market prices based on empirical observations, focusing on the following two phenomena: (i) the merit-order effect and (ii) negative prices.

The 'merit-order effect' describes the net effect of reduced wholesale electricity market prices triggered by renewable electricity generation due to its low marginal generation cost, which therefore shifts the rest of the supply curve. Empirical evidence based on comprehensive analyses in this respect is available for different electricity market regions worldwide. For instance, Praktiknjo and Erdmann (2016) provide

a summary of different studies for Germany, which estimate the merit order effect to be in the range of 5-13 €/MWh in the last decade. In Stefano et al. (2015), the merit-order effect in Italy was quantified below 5 €/MWh. Welisch et al. (2016) estimate the merit order effect in relative terms, and find a significant effect in most European countries, i.e. a price decline in the 0-1 €/MWh when the renewables share of load increases with one percent. Hirth (2013) also consider the merit order effect, and find that it significantly reduces the market value of renewables with increasing penetration levels in Germany. Wisser et al. (2017) review literature on the merit order effect in the United States, which in various studies is estimated to be from 0 to 9 \$/MWh depending on location and renewables penetration levels. They also perform an empirical analysis of price developments in the California (CAISO) and Texas (ERCOT) electricity markets, and find that the growth in VRE from 2008 and 2016 contributed less than 5% to the overall electricity price decline in the same period for both markets. In contrast, the reduction in natural gas prices contributes as much as 85-90% to the electricity market decline.

Another recent trend in electricity markets is the occurrence of negative prices. There are several drivers for negative prices. For instance, operational constraints and start-up costs may prevent some thermal generators from reducing their output although prices go below their marginal costs. Moreover, subsidies for renewable electricity generation and preferential treatment in the dispatch may also contribute to negative prices. For instance, in the case of PTCs in the United States, it makes economic sense for wind power generators to offer their electricity into the wholesale market with a negative cost equal to the PTC, since they will still make an operating profit as long as the market clearing price is above this level. If there is a surplus of supply in the system, these negative offers may set the market clearing price, thereby exposing other market participants to the same negative prices. Wisser et al. (2017) find that the frequency of negative prices is still low in major U.S. trading hubs. Still, negative price tend to occur more frequently in some areas with increasing renewables penetration, particularly in California. Moreover, specific locations are more exposed to negative prices due to transmission constraints. This is illustrated in Figure 5, which shows historical day-ahead and real-time prices for a selected node in the PJM electricity market, i.e. at a location with a nuclear power plant and substantial wind penetration in the neighboring region. The figure shows that negative prices occur as often as 10 % of the time in the real-time market, and the frequency has increase substantially over the last 10 years. In Europe, FITs are usually combined with priority dispatch for renewable resources. This gives rise to increased variability in net load, which combined with inflexibilities in the rest of the generation portfolio also may lead to negative prices. Figure 6 shows historical data for negative prices in the German electricity market EPEX (DE) for the period 2012-2016.

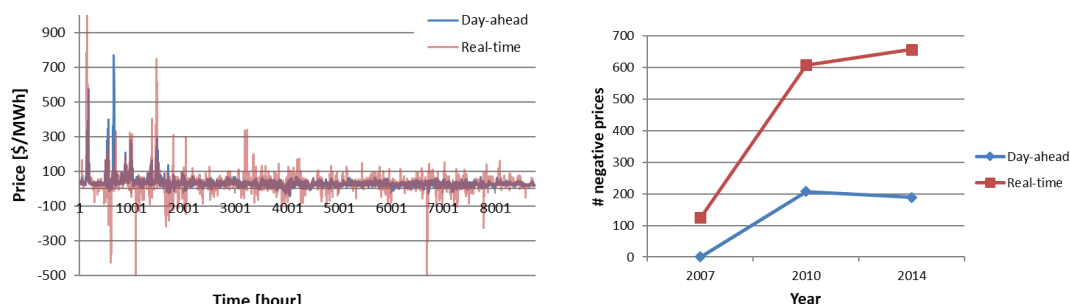


Figure 5 Hourly day-ahead and real-time prices in the PJM pricing node 4 QUAD C18 KV QC-1 for 2014 (left) and frequency of negative prices in three selected years (right). Data source: PJM.

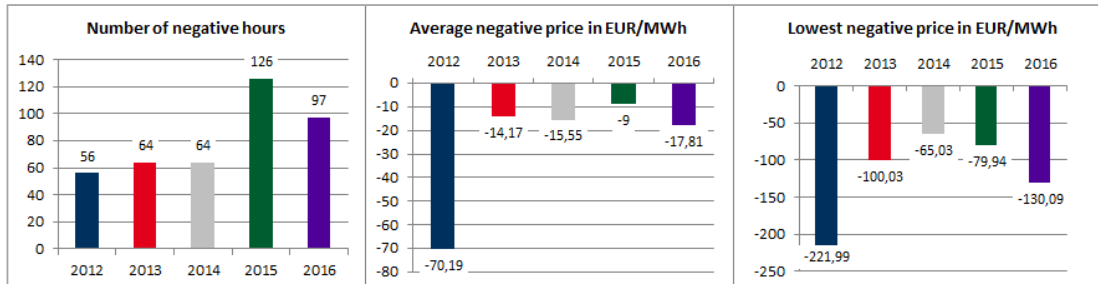


Figure 6 Negative wholesale electricity market prices in Germany in recent years (number of hours, average and lowest negative price): Source: Energy Brainpool (2017)

The recent low price levels observed in European and U.S. wholesale markets may not be sufficient to trigger investments into new generation assets, neither renewable nor other resources, through current market mechanisms. This is not necessarily a problem as long as there is still sufficient capacities in the market. In the longer-term, however, it is important that the electricity market sends out correct scarcity and price signals to trigger corresponding investments in new generation. In the ideal world, this works without any market intervention. For instance, liquid forward and futures markets would indicate adequate market price levels and investment incentives in the longer-term. In recent years, however, long-term prices did not signal any upward trend. Overall, these trends and challenges have given rise to current discussions around the need for capacity remuneration mechanisms and how to best design them. To evaluate these questions, we first briefly compare in the next section short-term electricity market operations in Europe and the United States before discussing electricity market design for resource adequacy in Section 4.

3 Short-term Electricity Market Operations in Europe and the United States

There are many general similarities in terms of short-term electricity market design elements in Europe and the United States. For instance, day ahead and real-time markets are generally operated in both places with similar timelines. However, when looking into the details there are also some important differences, and we highlight some of them in this section.

U.S. electricity markets are more closely linked to the physics of the power system than what is the case in Europe. One reason for this is that when Independent System Operators (ISOs) and electricity markets were introduced they were typically built into existing entities in charge of operating the power grid (e.g. in the PJM system). On the contrary, in Europe new Power Exchanges (PXs) were introduced as separate entities from the existing Transmission System Operators (TSOs), emphasizing wholesale electricity market trade and economics, including trading of long-term forward and futures contracts. Under the European model, the physical anatomy of the electricity system and system operation, which is still conducted by the TSOs, has therefore been more decoupled from market operation. Another difference is that a European TSO typically owns the grid infrastructure as opposed to the U.S. ISOs who are in charge of operating the power grid without owning it. Whereas in the U.S. system the price signals are calculated and sent to the market participants for each node of the transmission system (i.e. locational marginal pricing), in Europe zonal pricing is implemented where one price zone usually covers an entire country.¹ Additional differences between the European and U.S. models for short-term electricity market operations include:

¹ In the period from 2008-2011 the corresponding number of hours with negative prices was: 15, 71, 12 and 15.

² Note that whereas some countries (e.g. Norway, Sweden, Italy) are split into more than one price zone other price zones consist of more than one country (e.g. Austria is part of the Germany price zone, although recently a mechanism was implemented to suspend cross-border trade, if necessary, during critical load flow situations in the electricity system). Moreover, price congestion may still occur frequently within a price zone and the lack of disaggregated pricing results in different measures to manage electricity flows in the meshed transmission grids within a price zone (e.g. to overcome intra-zonal congestion by activating so-called “re-dispatch”). A number of

- Electricity market operators in the United States usually apply a centralized unit commitment model for power plant scheduling, where market participants provide complex bids, including start-up costs and operational constraints. In contrast, European market operation typically relies on simpler bids without accounting for detailed unit commitment constraints, which are left for the individual generation companies to resolve internally.
- In U.S. electricity markets, a reliability unit commitment typically takes place between day-ahead and real-time operation, where the ISO can commit additional units for reliability purposes based on its updated forecasts for load and renewable electricity generation. In contrast, European electricity markets rely more on intraday markets organized by PXs, which enables market-based re-dispatch where market participants can adjust their positions based on their own information.
- The trend in U.S. markets is to implement co-optimization of energy and reserves, i.e. joint energy and reserve market clearing as part of the centralized unit commitment and economic dispatch done by the ISO. In contrast, in Europe energy and reserve markets are typically operated sequentially with separate bidding and market clearing mechanisms, and the markets may also be run by different entities (PXs vs. TSOs).
- U.S. real-time markets are run with high time resolution, i.e. dispatch signals and prices are typically calculated every 5 minutes. European balancing markets are operated with lower time resolution, i.e. typically 15-30 min.
- In Europe, schedule management of Balancing Responsible Parties (BRPs), i.e. entities with the responsibility of balancing a portfolio of resources, enables (and partly incentivizes) trade of imbalances among BRPs directly. This approach of decentralized balancing is not foreseen in U.S. markets where the ISOs conduct imbalance pricing and settlement on aggregated levels only.
- In U.S. electricity markets, the trend has been to consider utility-scale VRE as “dispatchable” resources, i.e. these resources can be dispatched down in constrained situations for economic reasons. In contrast, VRE generation is typically denoted “must-take” by European TSOs with curtailment only occurring for reliability reasons.
- Retail competition is present across Europe. However, fixed/uniform retail tariffs are still prevailing in most countries. Customer choice in the retail market is not based on flexibility products/tariffs, but rather on the absolute uniform price or the ‘green’ product level. Switchover rates of customers are still moderate. In the United States, retail sales of electricity are regulated at the state level, and relatively few states allow retail choice. Texas is the state with highest switchover rate for residential customers.

It is important to recognize that the discussion above only provides a high-level comparison of more general features of electricity markets, and that substantial regional differences exist within Europe as well as the United States. Still, the discussion serves to illustrate that there are some fundamental differences in how electricity markets are operated on the two continents. This influences the short-term prices formation and, in turn, the price and scarcity signals which are essential to maintain resource adequacy and system reliability in the long run. Next, we take a closer look at the capacity adequacy challenge and potential solutions that have been implemented or are being considered in both regions, in response to more VRE in the power system.

4 Electricity Market Design for Resource Adequacy

As a consequence of prolonged low wholesale electricity market prices in both U.S. and European electricity markets the long-standing discussion on how to best incentivize investments in new electricity generation capacity has been re-emerging in recent years. Moreover, different concepts are on the table for market intervention to deliver sufficient electricity generation capacity in order to ensure long-run system reliability. In this section, we first give a brief overview of theoretical underpinnings and arguments behind existing approaches to address resource adequacy, from energy only markets to various capacity mechanisms. We then discuss the current status in terms of policy mechanisms to support long-run resource adequacy in European and U.S. electricity markets.

efforts, including flow-based market coupling, are currently underway by ENTSO-E to better align the different price zones within the European electricity markets (see e.g. https://electricity.network-codes.eu/network_codes)

4.1 The Challenge of Maintaining Resource Adequacy in Electricity Markets

The challenge of how to incentivize sufficient generation investment to meet long-term reliability needs has been a focal point in electricity market design discussions since the early days of industry restructuring. Stoft (2002) points out two so-called demand-side flaws that prevent proper price formation during scarcity conditions in the power grid: (i) limited demand side flexibility and therefore ability for consumers to respond to price, (ii) inability to differentiate between consumers in terms of reliability. These flaws may lead to situations where there is insufficient capacity to meet demand. In economic terms, this means that the supply and demand curves do not cross, and a price has to be determined administratively as opposed to reflect consumer preferences as expressed in a demand curve. The preference of regulators to protect consumers from potential market power abuse and high energy prices tend to give price caps below the value of lost load (VOLL), and therefore reduced generator income during scarcity periods. In turn, this leads to the so-called “missing money” problem, where generators do not receive sufficient income to recover their total capital and operating costs. At the same time, system planners typically need to meet strict reliability requirements (e.g. in the United States, keeping supply shortages to less than 1 day in 10 years is the common planning standard). These traditional reliability requirements may actually be higher than what a strict economic analysis would yield, depending on the assumed VOLL (Brattle Group and Astrape, 2013).

Two main pathways have emerged to address resource adequacy challenges. One direction focuses on improving price formation in short-term markets (e.g. Hogan, 2005), thereby creating more robust price signals for long-term investments. The second direction argues that explicit capacity remuneration mechanisms, such as capacity markets are needed to ensure system reliability in the long run (e.g. Batlle and Pérez-Arriaga (2008), Cramton et al. 2013). However, there is no consensus on what is the best way of achieving long-run resource adequacy at the lowest cost. How to address the associated challenges with more renewable generation in the grid is also an open question.

Figure 7 illustrates how the cost recovery challenge for thermal generators is influenced by increasing shares of renewables in the power system. For the sake of simplicity, the thermal generation system consists of two technologies: nuclear power plants for baseload generation and Combined Cycle Gas Turbines (CCGTs) for mid and peak load coverage. Compared to the CCGT technology, a nuclear power plant is characterized by higher fixed cost and lower operating cost, which explains the shape of the average and marginal cost curves for the two technologies. As the amount of VRE increases in the system, the thermal generators are dispatched less. Hence, the annual generation decreases while the average cost increases, accordingly. This effect is most pronounced for the CCGT, but also influences the nuclear plant (assuming it is flexible and dispatches down during high renewables output). These effects increase the difference between the average and marginal cost for both thermal technologies, exacerbating the cost recovery challenge as the plants have to earn at least its average cost to break even.

In principle, the difference between the average and marginal cost for an individual plant can be recovered in multiple ways. For instance, during scarcity prices in the energy market would rise to levels above the highest marginal cost unit providing scarcity rents to all generators. These scarcity rents will become more important with more renewables due to higher difference between average and marginal costs (Figure 7). Moreover, as renewable levels increase, some thermal generators may decide to exit the market, potentially leading to less competition and higher offer prices, which may also provide additional rents. However, if the energy market fails to provide the required revenues for cost recovery, the difference between average and marginal cost may be interpreted as the missing money that needs to be recovered from explicit capacity mechanisms. Under this interpretation, capacity mechanisms play an increasingly important role with more renewables in the system. A final observation is that the total generation cost of the system moves towards a higher share of fixed cost and a lower share of variable costs with more renewables, particularly considering that wind and solar energy both are basically fixed cost resources. We note that natural monopolies are characterized by economies of scale and high fixed costs. However, in contrast to electricity transmission, we argue that limited sunk costs and relatively low barriers to entry in the generation business will ensure that competitive market still can prevail for generation, also in a high renewables system. Next, we discuss in more detail the two main design paths for competitive electricity markets, i.e. with and without an explicit capacity remuneration mechanism, and how they are impacted by more renewables in the power system.

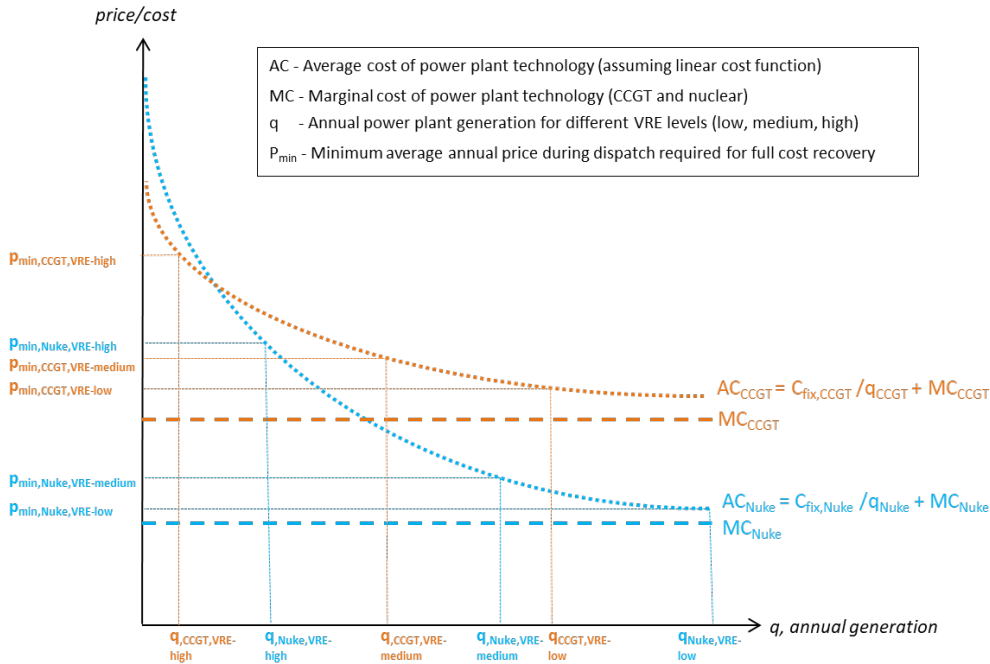


Figure 7 Illustration of average and marginal cost of two representative power generation technologies, combined cycle gas turbine (CCGT) and nuclear power (Nuke), for different levels of VRE generation in the system.

4.1.1 Market Design without Explicit Capacity Mechanisms: Energy-Only Markets

In economic theory marginal cost pricing denotes the first best solution in competitive markets. Moreover, in non-distorted markets this approach sends the correct price and resource scarcity signals to the market participants. In electricity, this is the underlying assumption for so-called “energy-only” markets that rely on the short-term market clearing prices for energy (and reserves) to provide incentives for operation and investment. In theory, well-designed energy-only markets should be sufficient to guarantee resource adequacy. It can be shown that in a perfect electricity market in a state of long-term equilibrium, marginal cost pricing would ensure that power plants in the optimal mix of generation resources exactly cover their investment and operating costs, as long as the price is set equal to the true VOLL during short periods of scarcity (e.g. Green, 2000). However, in addition to the challenges of limited demand flexibility, price caps, and strict reliability standards, additional factors may prevent optimal price formation in energy only markets, as briefly discussed below.

The rapid expansion of VRE may exacerbate the missing money problem and therefore the resource adequacy challenge (Ela et al. 2014). Wind and solar resources have high capital costs, but zero (or even negative under certain support schemes) marginal cost, which tend to reduce wholesale electricity prices, at least in the short term, as discussed in Chapter 2.2. At the same time, the high variability in these resources tend to reduce the capacity factors of dispatchable generators, while at the same time giving rise to higher system flexibility needs. Overall, specific support for selected technologies (whether renewables or thermal technologies) jeopardizes non-discriminatory treatment in electricity generation. Another challenge frequently encountered in electricity markets is that the number of market participants on the supply side is typically limited. In this case, there is the potential for exertion of market power or collusion among dominant players. Limited liquidity in long-term forward contracts is also a challenge, as it may prevent adequate long-term hedging opportunities for investors in new generation capacity as well as for consumers who want to reduce their exposure to price spikes and potential price increases in the long run.

Despite these challenges, energy-only markets have several advantages. First, this approach lets the market participants determine investments in new generation capacity, both in terms of technology choice and quantity. One of the primary motivations for the introduction of electricity markets in the

first place was to avoid centralized decisions about generation expansion by letting market participants decide on generation investments, while also facing financial consequences from making imprudent investment decisions. The energy-only market approach leaves generation expansion decisions to market participants, although the price formation is still influenced by regulatory decisions (e.g. about price caps in energy and reserves markets). Moreover, the energy-only market provides strong operational incentives, as generators cannot rely on income from mechanisms other than energy and reserves markets to recover their costs, and they are heavily penalized if not available during scarcity situations when prices and scarcity rents are high.

Proponents of the energy-only approach argue that the advantages of the energy-only market outweighs the risks, also as more renewables are added to the system. To achieve resource adequacy in the long run, the main focus should therefore be to improve price formation in energy and reserve markets. Improved scarcity pricing is a key challenge in this context. This can be achieved by increasing price caps in energy and reserve markets, and also by enabling more demand response. Moreover, in the absence of extensive demand participation, moving from fixed operating reserve requirements to demand curves for operating reserves will also introduce some demand flexibility and improve short-term pricing, particularly during scarcity conditions (Hogan, 2005). Operating reserve demand curves can be dynamically estimated to reflect the amount of uncertainty in forecasts for renewable generation, thereby better reflecting the impacts of renewables in the price formation (Zhou and Botterud, 2014). Simulations of future electricity markets indicate that dispatchable technologies that are part of the optimal generation mix continue to break even in an energy-only market with higher wind penetration levels. Moreover, the operating reserve demand curve approach tend to give a more continues spectrum of energy and reserve prices and therefore less reliance on a few scarcity hours for generators to recover their costs (Levin and Botterud, 2015). Another important direction for improving energy-only market is to create more liquidity in long-term markets so that market participants effectively can hedge their risk exposure to future price fluctuations and spikes (both positive and negative).

4.1.2 Market Design Options **including** Explicit Capacity Mechanisms

Proponents of having explicit capacity mechanisms argue that energy-only markets do not provide sufficient incentives to maintain reliability in the power system, due to the various challenges discussed above. Explicit capacity mechanisms can be classified into quantity-based and price-based instruments (Figure 8). In the following, we briefly discuss the most common capacity mechanisms and their pros and cons.

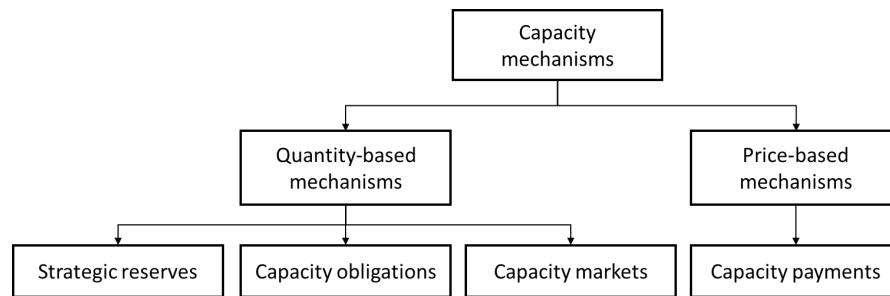


Figure 8 Overview of the main capacity mechanisms.

- **Strategic Reserves:** Most of the generation capacity operate in the competitive “energy-only” market, but some additional regulated peaking capacity operate outside the regular market. These regulated peaking generators constitute the strategic reserve which guarantees prescribed amounts of installed and ready to use peak generation capacity. In practise, the TSO purchases and manages the strategic reserves under predefined rules. Advantages of strategic reserves are the high level of control for the system operator and that that strategic reserve provides generation capacity that is prevented from retirement to meet reliability purposes in the future. However, a major disadvantage of this mechanism is the substantial intervention into the electricity market.
- **Capacity Markets:** Centralized auctions for capacity where load serving entities can purchase capacity to meet their capacity margin requirements, as determined by an independent entity like the system operator or a regulatory authority. The system demand for capacity in the auction is

administratively determined to meet certain reliability targets. The contracts traded in the auction can be forward contracts for capacity or so-called reliability options, i.e. a contract that hedges consumers against short-term prices in the energy market exceeding a certain strike price (Vazquez et al. 2002). In both cases, the capacity market provides an additional revenue stream for generators to make up for the missing money problem in the energy market. One advantage of the capacity market mechanism is that a targeted reliability/capacity level is reached with a high level of confidence. Furthermore, the market intervention is relatively limited. A disadvantage is that generators are confronted with uncertain revenues, since market clearing prices in the capacity auctions are likely to fluctuate. Moreover, the demand for capacity, which is critical for the capacity price formation, is determined by a large and complex set of administratively determined parameters.

- **Capacity Obligations:** This instrument guarantees that a regulated generation adequacy target for the system is determined by assigning capacity obligations to individual load serving entities. However, in this case there is no centralized capacity market, and capacity is rather obtained through self-supply or bilateral contracts with generators. The capacity obligations may also specify requirements for different types of generation capacity to ensure reliability (Ela et al. 2014). Advantages of capacity obligations are that they can be implemented as centralized or decentralized solutions and they can easily consider contributions from demand response and energy storage. Moreover, flexibility requirements can be achieved in addition to capacity. However, a major disadvantage of this approach is the high degree of centralized planning.
- **Capacity Payments:** A capacity payment is a price-based mechanism that provides an extra remuneration to individual generators for guaranteeing generation adequacy. This could discourage retirement of old generation capacity and incentivize investments in new capacity. Moreover, it simultaneously stabilizes volatile revenues of generators on the wholesale electricity market and reduces the wholesale electricity market price level due to extra firm capacity available. However, the mechanism has limited precision, meaning that it may not achieve the desired reliability/capacity levels. Moreover, generators may be financially over- or undercompensated, which can easily lead to an inefficient outcome.

The ultimate question, however, is if any of these capacity remuneration instruments are needed or if amendments in existing electricity market structures and market designs for energy and reserves markets are sufficient to maintain generation (and transmission) adequacy in the long-run. It is important to note, that the requests from generation companies for capacity remuneration mechanisms oftentimes neglect the option to improve existing “energy-only” electricity market structures. One additional complication in the context of capacity remuneration mechanisms is the potential for market distortion in case of different mechanism in neighboring countries, which could undermine free competitive cross-border electricity markets (e.g. EC (2014), Frontier Economics (2014), Meyer et al. (2014)).

4.2 Current Status in Europe and the United States

4.2.1 Capacity Mechanisms in Europe

Several different capacity remuneration mechanisms are currently implemented in Europe, as illustrated in Figure 9. Moreover, the overall picture is evolving, as some countries have recently introduced or changed capacity remuneration mechanisms, whereas others are considering changes in the near future. Note that all the different mechanisms discussed above currently exist in Europe. Strategic reserves are used in Belgium, Poland, Sweden, and Finland, although the latter two countries plan to phase them out by 2020. Capacity payments exist in Spain, Portugal, Italy, Greece, Ireland, Latvia, and Lithuania. A capacity market was introduced in Great Britain in 2014, whereas France introduced a decentralized version of capacity obligations the same year. Other countries, notably in the North and Southeast of Europe rely on the energy-only market solution. Hence, the overall picture is very heterogeneous.

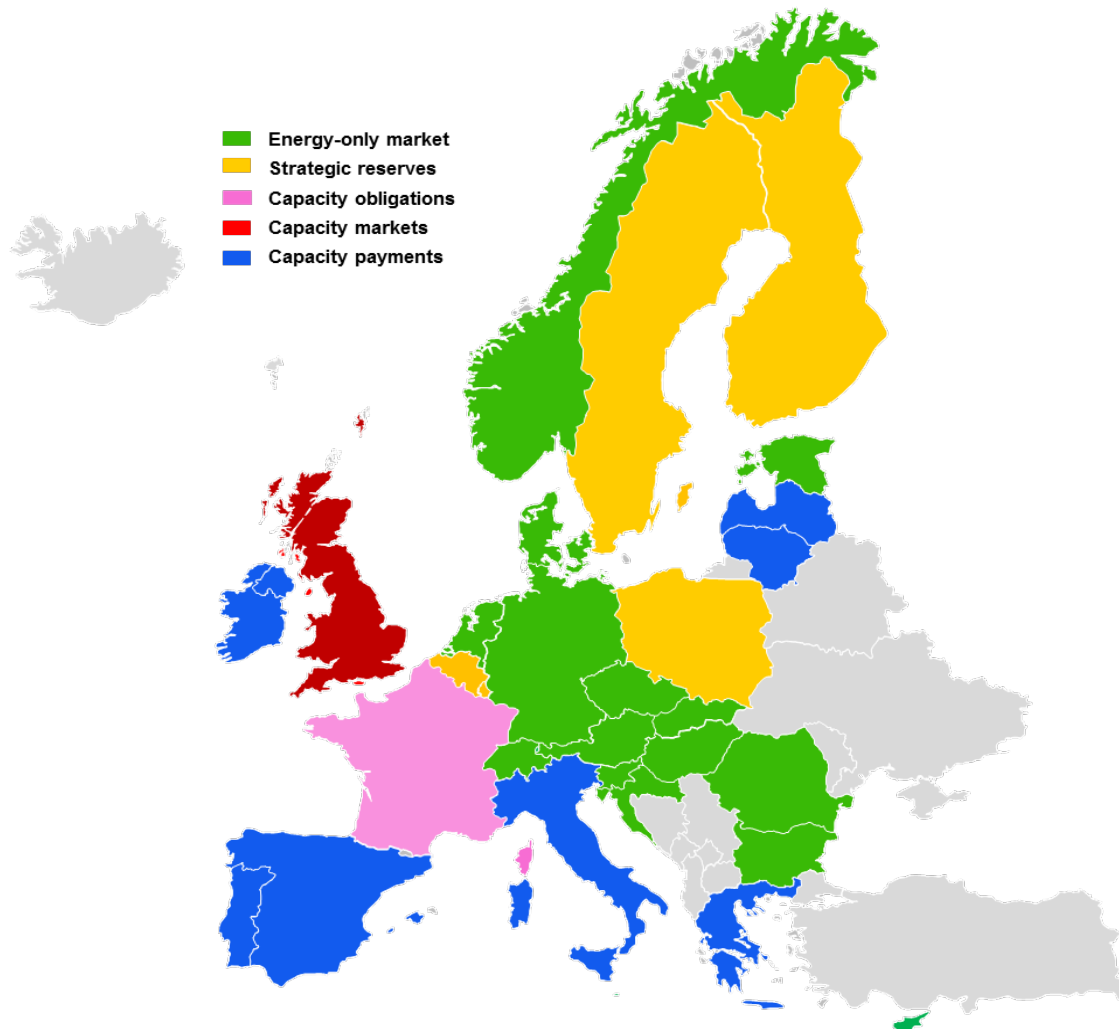


Figure 9 Capacity mechanisms implemented in the European Union, Norway, and Switzerland.
Source: EEG-EEMD (2017).

To some extent, the different capacity remuneration mechanisms reflect different conditions and structural patterns in the respective national power systems. In areas with minor resource adequacy problems “energy-only” markets tend to prevail, not least as a result of sufficient existing (depreciated) generation capacities, oftentimes with significant shares of hydro power in the portfolio, like in Norway and Austria. Other areas have serious resource adequacy problems in the medium term since significant amounts of generation capacities are scheduled to be decommissioned in the upcoming decade. For instance, Germany plans to phase out their nuclear generation by 2022 and in France a large-scale decommissioning of nuclear power plants is expected beyond 2030. In other cases, e.g. Spain, it is rather a profitability problem than a physical scarcity problem of generation capacity. More precisely, this means that low wholesale electricity market prices are not sufficient to depreciate rather new generation capacities. Therefore, generation companies are arguing that capacity mechanism are needed to increase profitability of existing power plants, including relatively new gas-fired generation.

The different examples above indicate that there are different drivers in Europe for adequate remuneration of electricity generation capacities and subsequently for corresponding wholesale electricity market price levels. A certain wholesale electricity market price level is required to avoid short/medium-term profitability challenges and send out the correct price signals for investments into new generation capacities (or repowering of existing ones). At the same, price signals should reflect the conditions in the market and the level of scarcity in the system. Low prices on its own is not necessarily a market failure if it reflects surplus capacity in the system.

4.2.2 Capacity Mechanisms in the United States

There is also a diversity of solutions to address resource adequacy in the United States, as illustrated in Figure 10. In the areas with regional electricity markets, solutions range from capacity markets (ISO-NE, NYISO, PJM, MISO) to capacity obligations (CAISO, SPP) and also one example of an energy only market (ERCOT). The regional markets in the Northeast has a long experience with capacity markets, as early versions were introduced as part of the overall restructuring of the electric power industry in the late 1990s. The individual markets have gone through a number of revisions since then, e.g. by extending the time horizon for capacity auctions, introducing downward sloping demand curves for capacity, and with a recent focus on introducing more stringent performance incentives (Bushnell et al. 2017). The latter was triggered, in part, by the experience with very cold weather (the Polar Vortex) in the winter of 2014 where a substantial part of the generation capacity was unavailable and created scarcity conditions. Among the three markets, ISO-New England is the only one where the capacity product is formulated as a reliability option, as opposed to a forward contract for capacity (Byers et al. 2017). MISO introduced its capacity market more recently, i.e. with the first auction for delivery in 2013. In MISO, the capacity market is voluntary and serves as one of several mechanisms that load serving entities can use to meet their local planning reserve requirements. CA-ISO and SPP basically use a capacity obligation approach without a capacity market, i.e. load serving entities must meet their capacity requirements through self-supply or bilateral contracts. Finally, ERCOT relies on an energy only market and has taken several measures to improve scarcity pricing in their energy and reserves markets, including a high price cap and a demand curve for operating reserves (Hogan, 2013). Improved scarcity pricing is also one of the topics that the Federal Energy Regulatory Commission (FERC) is focusing on as part of their efforts to improve price formation in energy and reserves markets (FERC, 2014). For instance, demand curves for operating reserves are also implemented in ISOs with capacity markets, although in a more simplistic manner than the approach in ERCOT. Finally, a substantial part of the country still operates under traditional rate of return regulation, with vertically integrated utilities doing integrating resource planning. For a more detailed discussion on the status of capacity mechanisms in the United States, we refer to Bushnell et al. (2017).

An important observation in reviewing the different capacity mechanisms in the United States is that investments in new generation capacity has occurred under all the different regulatory structures over the last 15 years (Bushnell et al. 2017). Moreover, current capacity margins and reliability levels remain high in the bulk power system across the country (DOE, 2017). The fact that there has been almost no increase in the national electricity consumption since 2005 has made it an easier task to maintain system reliability. Still, large regional differences exist in terms of the growth in electricity consumption. For instance, the New England region has seen a drop in electricity consumption of almost 10% between 2005 and 2016, while Texas has experienced a growth of more than 15% in the same period. It is therefore hard to see a relationship between the need for new investments in generation capacity and the evolution of capacity mechanisms in this period. A recent expert survey of U.S. capacity markets reveals a wide range of opinions on the functioning of U.S. capacity markets, with the overall conclusion that capacity markets have met their objective with respect to reliability, but in an economically inefficient manner (Bhagwat et al. 2016).

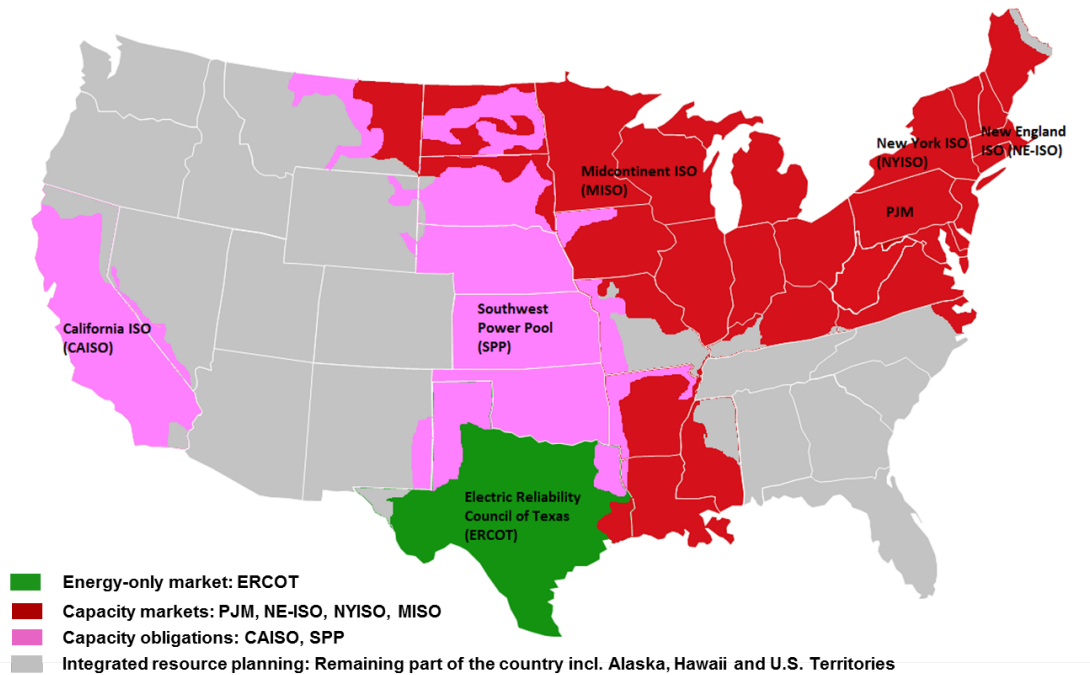


Figure 10 Overview of capacity mechanisms in the United States.

5 Recommendations for Improved Electricity Market Design

The discussion so far illustrates that there are important similarities as well as substantial differences when it comes to electricity markets and the impacts of VRE in Europe and the United States. In this section, we provide some recommendations for improved electricity market design, as market reforms are being considered and implemented on both continents in response to increasing shares of VRE. Our recommendations, as summarized in Table 2, are based on the principle that short-term prices for energy and reserves are the most important instrument for providing adequate incentives for operation as well as investments. In a perfect world, the energy-only market provides sufficient incentives for resource adequacy. However, a range of factors influence the price formation in the short-term markets, and this also influences the long-run market and investment signals. Hence, the first order of priority should be to establish well-functioning short-term markets for energy and reserves.

Our general recommendations for market design improvements therefore focus on removing biases in electricity prices. For instance, pricing of environmental externalities such as carbon emissions is a more market compatible approach to encourage investments in renewable resources than technology specific incentive schemes, which tend to reduce electricity prices. Moreover, a sharper price formation can be obtained through improved scarcity pricing, which in turn provides better incentives for system flexibility from supply, demand, and energy storage resources. With the increase in distributed energy resources, it is also increasingly important that high-resolution price signals reach market participants in the distribution grid. Improved price formation in short-term markets may not fully remove the need for separate capacity mechanisms, but should at least reduce the reliance on such mechanisms to obtain resource adequacy.

Specific improvements for electricity markets in Europe include an improved representation of the transmission network to obtain locational short-term prices that better reflect congestion patterns. A full nodal pricing model, like in the United States, is probably infeasible in the European context, although we note that the recent implementation of flow-based market coupling is a step in that direction. Moving towards shorter time intervals in real-time balancing markets as well as going from sequential markets for energy and reserves to one integrated market co-optimizing both products, as is already done in some U.S. markets, would contribute to further improvements in price signals in European markets. In the United States, we argue that efforts should be made to increase the liquidity and transparency in long-

term markets. In Europe, this is to some extent achieved through trading of long-term contracts on power exchanges. Moreover, intraday markets should be introduced in the United States to enable a more market-based balancing of system deviations between the day-ahead and real-time markets (see also e.g. Herrero et al, 2016). Ongoing efforts towards improved price formation in U.S. markets also include moves towards 5 min settlements in real-time markets, full co-optimization of energy and reserves, and refinements to operating reserve products. A common challenge in both continents is to improve the coordination between system operators in different regions.

Table 2 Summary of suggested market design improvements

<u>General electricity market improvements</u>	
<ul style="list-style-type: none"> • Gradual removal of technology specific subsidy schemes for clean energy • Adequate pricing of carbon and other environmental externalities as a more market compatible incentive scheme for clean energy resources • Improved price formation in energy and reserves markets, particularly during scarcity conditions • Move day-ahead markets closer to the operating day • Improved incentives for provision of system flexibility from supply, demand and energy storage • Enable participation of distributed energy resources and demand response in electricity markets • Reduce reliance on explicit capacity mechanisms to incentivize investments 	
<u>Specific improvements for Europe</u> <ul style="list-style-type: none"> • Improved representation of transmission in market clearing to better reflect congestion in prices • Imbalance netting to avoid opposite activation of frequency reserves in neighboring zones • Shortening timeframes in intraday market • Higher frequency of real-time dispatch and market clearing • Co-optimization of energy and reserves instead of sequential/separate markets • Economic dispatch of renewable resources • Better coordination between TSOs • Further develop retail competition, notably in terms of introducing more flexible and variable pricing/tariff products 	<u>Specific improvements for United States</u> <ul style="list-style-type: none"> • Increased liquidity and transparency in long-term contracts • Implementation of intraday markets for market-based balancing • Higher time resolution of settlements in real-time energy and reserve markets • Further refinements of products in ancillary services markets • Full co-optimization of energy and reserves in all regional U.S. markets • Better coordination between regional capacity, energy, and reserves markets • Open up for retail competition in larger parts of the country, along with innovations in flexible pricing/tariff design

6 Conclusions

The comparison of European and U.S. electricity market design in the presence of increasing shares of VRE generation has shown a more distinct influence of VRE on wholesale electricity market prices in Europe compared to the United States so far. Most notably, our review of literature and data indicates a decoupling from correlation with natural gas prices in several regional markets in Europe in recent years. One of the main drivers for this development in Europe has been the large increase in VRE, driven in part by technology specific, support policies for VRE technologies. Different VRE incentive schemes have triggered significant investments in renewable generation technologies in the United States as well, although the penetration level is about half of what is the case in Europe.

One of the most significant distinctions in terms of electricity market design is that U.S. markets in general are more aligned with the physics of the power system, mainly focusing on daily operation with day-ahead and real-time markets run by the system operator. In contrast, in Europe intra-day, day-ahead and long-term markets are typically operated through separate power exchanges. Under the U.S. market structure the system operator solves a larger part of the ‘optimization’ problem whereas under the European model more ‘optimization’ is left to the market participants. The U.S. approach has advantages in terms of more centralized coordination and control, whereas the European model may be preferable from a pure market’s perspective.

We provide some specific recommendations for future electricity market design in Europe and the United States (Table 2). From a more overarching perspective it is important to note that no single solution exists; each of the two market paradigms have favorable elements and also needs for improvements. Hence, lessons can and should be learned in both directions. Independently of a particular market design, we argue that the most important issue is to achieve a good price formation in the short-term markets. The first objective should therefore be to improve the energy-only markets, thereby fostering a more market-compatible integration of VRE into current electricity markets. Capacity mechanisms should be considered a back-up solution only, i.e. to be implemented only if short-term price formation is not sufficient to provide investment incentives. In that case, it is important that explicit capacity mechanisms cause minimal market distortions. When it comes to support schemes for renewable energy and other incentive mechanisms, it is important that they do not have technology-specific preferences but rather deliver the best technology portfolio. In the long run, pricing of externalities such as carbon emissions is more compatible with the well-functioning of electricity markets than direct support schemes for specific VRE technologies, which have been the dominant incentive scheme to date in both Europe and the United States. Hence, internalization of carbon costs through transparent and non-discriminatory mechanisms (e.g. adequate carbon trading or taxation) remain a challenge in both systems.

Overall, it is important not to lose sight of the overarching challenge of improving electricity markets and developing more market compatible VRE integration schemes. The alternative, increasingly severe market interventions and solutions akin to integrated resource planning will only take us back to where we started with electricity restructuring more than 25 years ago.

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