




Market Designs for High Levels of Variable Generation

Preprint

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***Abstract*—Variable renewable generation is increasing in penetration in modern power systems, leading to higher variability in the supply and price of electricity as well as lower average spot prices. This raises new challenges, particularly in ensuring sufficient capacity and flexibility from conventional technologies. Because the fixed costs and lifetimes of electricity generation investments are significant, designing markets and regulations that ensure the efficient integration of renewable generation is a significant challenge. This panel presentation reviews the state of play with regard to these issues in the United States and Europe and considers new developments in both regions.**

***Index Terms*—wind energy, power markets, adequacy, capacity**

I. Introduction

Power systems have changed considerably in recent years. The liberalization of electricity markets has taken place on many systems, particularly in the United States and Europe. Concerns about climate change and energy security have led to a policy shift from fossil-fueled generation toward variable renewable generation (VG), particularly wind and photovoltaics. These generation sources differ from conventional generation in terms of the variability and limited predictability of their output, their high capital costs and negligible operating costs, and the impact of geographic location on their output. Thus, market mechanisms that were designed to ensure efficient investments and operations of conventional generation may not prove efficient in integrating renewable generation. Difficulties include ensuring revenue adequacy for all market participants in markets with depressed spot prices; market scheduling, particularly between interconnected markets; and ensuring efficient transmission investments and operations. The low operating costs of renewable generation—along with nuclear, hydro, and combined heat and power generation—depressed spot prices, and energy-only markets are unlikely to provide sufficient investment incentives. These challenges have seen varied responses from system operators and regulators through both market and regulatory mechanisms. This panel presentation examines the implications of these challenges in current modern power systems. Responses from regulators and policy makers are examined, with a focus on late-breaking work in both the United States and Europe.

II. Market Challenges from VG

Increased variable and limited predictable renewable generation places new requirements on power system operations and electricity markets. Variability and uncertainty means that more flexibility will be needed. Also, increased amounts of VG displace fossil-fueled generation and lead to less operating hours for conventional generation—as well as decreased electricity prices during hours of high renewable generation.

A. Requirements for Flexibility

Renewable VG leads to higher variability in residual demand, which is given by demand minus renewable generation. This residual demand must be met by conventional generation units. At moderate VG penetration levels, mid-merit power plants will operate in a more flexible way. At high penetration levels, baseload operation will also be impacted.

There is significant interest in developing methods for assessing the flexibility needs and characteristics of the power system [1]; however, installing sufficient flexibility in the power system is not a sufficient condition for making that flexibility available when needed. Appropriate mechanisms that allow system operators to obtain those services when necessary are also required to maintain system balance. Existing market regulations and designs may not incorporate sufficient incentives and rewards for flexibility that will be required to ensure both efficient system operation and renewable integration.

Obtaining deployable flexibility has two components: (1) the economically efficient level of investment in flexible technologies must take place, and (2) once installed, price signals or regulatory requirements must incentivize generators to make these flexible capabilities available to system operators. As variable renewable penetration increases, flexible units may be operated in a manner that reduces their capacity factors and their online durations relative to those of baseload units, which in turn have reduced revenues.

Therefore, an energy-only market—in which remuneration is awarded for only energy provision and not performance—may penalize flexible units. Further, flexible units are more likely to serve as marginal units, so they cannot gain inframarginal rent during the hours that they set the market price. Regulatory measures designed to limit scarcity pricing, such as price caps, can exacerbate this problem. Reduced spot prices from technologies with low marginal costs reduce returns for conventional generators even further. Thus, there is cause for concern that traditional energy-only markets may lead to revenue inadequacy for conventional units and will also penalize flexible units. An energy-only market with only short-period trading can be found in Australia. (It is a 5-min real-time market with a very high price cap.) This design was presented in [2] and mitigates some of the above-mentioned challenges.

B. *Revenue and Price Impacts of Wind Penetration*

Various studies have been conducted regarding the impacts of renewable generation on both electricity prices and the revenue that all types of generators can expect to earn. Renewable electricity is understood to reduce prices through the merit order effect, whereby renewable electricity is regarded as that from low, short-term, marginal-cost generators. Thus, the supply curve is shifted to the right and intersects the demand curve, which is fixed, at a lower point, leading to lower prices. In the longer term, as old generation is retired and consumption may increase, the price curves will again cross at a higher level, on average, but with increased volatility. In Europe, several ex-post analyses have found that wind penetration leads to lower wholesale prices, with the reduction in prices greater than the subsidy mechanisms awarded to renewable generation [3]-[6]. In [7], it is found that the impact of increased wind generation on system balancing costs is much lower than estimated wind integration costs.

In the United States, there has been concern regarding revenue adequacy even without significant VG. For example, New York (NYISO), which has a relatively small amount of wind energy, experienced prices below the cost of new entry in 2011 and 2012, according to a recent market report [8]. Market prices are coupled with both the dispatch stack and transmission constraints. In the United States, there have been cases of curtailment of wind power that were done outside of the market construct, resulting in uneconomic outcomes [9]. These generally occur during periods of low demand, high wind output, and with other generation constrained at minimum output. Several market areas in the United States now do some form of economic dispatch on wind plants so that the impact on low/negative market prices is mitigated [10]. In European countries with high wind penetration, negative market price signals are used to incentivize the downward dispatch of low-marginal cost units. The use of new forms of demand is also incentivized this way, e.g., heat boilers in the district heating system. When neighboring markets do not have synchronized price floors, a phenomenon can be observed in which bids are cut in one market while energy is imported into the same market, resulting in negative prices on both sides of the border [9].

III. OVERVIEW OF CURRENT MARKET STRUCTURES

Market designs in Europe and the United States vary considerably, both between the two continents and among different markets and systems within each continent. The European Directive 2009/72/EC [11] requires member states to adapt their national laws, making countries move toward a common internal energy market (IEM) to be finalized by 2014. Objectives of the IEM include requiring increased market coupling via interconnectors between different regions. Markets in the United States must comply with regulatory orders set by the Federal Energy Regulation Commission. When considering renewable integration, of particular interest are day-ahead and intraday markets, capacity payment mechanisms, and locational versus zonal marginal pricing.

A. *Day-Ahead and Intra-Day Markets*

Future very-high penetration levels of low, short-term, marginal-cost units can profoundly change energy-only markets. For example, the Nordic market, which is hydro dominated, needs conventional generation to set prices as well as to optimize the use of water. Adding VG to this system will push conventional generation out, with only biomass-fueled combined heat and power remaining.

Many current power market structures have a day-ahead market closing approximately 12 to 36 hours before the real-time operation. The day-ahead market creates the first committed schedule. As the hour of operation gets closer, forecasts improve, and intraday markets can then be used to provide updated market positions. For example, the Nordic power system has a continuous intraday market that closes one hour before the operating hour, whereas the Spanish market has six intraday market sessions. The former results in a shorter gate closure, whereas the latter creates more liquidity. Finally, the transmission system operator manages the power system in real time with the help of ancillary service markets and reserves.

The proposed IEM requires harmonized trade over interconnectors, which should lead to a zonal market structure. All balancing area's market participants are required to combine price and quantity pairs and submit these pairings to a power exchange that will in turn determine efficient interconnector flows on that basis. Further intraday trading then takes place within the market zones, with implicit trading between market zones. Each system has room for discretion to arrive at its price-quantity pairs, whether through bilateral trading, centralized dispatch, or some combination of the two.

B. *Capacity Payment Mechanisms*

Capacity payment mechanisms are mechanisms whereby units receive payments on the basis of their capacity and/or availability. Capacity payments are used as a means of responding to the "missing money" problem of revenue inadequacy as outlined in Section II. In general in Europe, two groups of capacity remuneration mechanisms are discussed: volume-based versus price-based mechanisms. Volume-based mechanisms can be targeted (strategic reserve) or market-wide (capacity obligations, capacity auctions, or reliability options). The most important requirement is to serve the purpose of ensuring generation adequacy without causing distortion to the market. An analysis of the challenges with respect to the different mechanisms has been made by the Agency for the Cooperation of Energy Regulators (ACER) [12].

Experience with capacity payments to date is mixed. The single electricity market in Ireland has had a capacity payment mechanism in place since 2007. Ireland currently has capacity that far exceeds peak demand, but because this is in part because of a collapse in demand since 2008, it is difficult to determine whether the structure of the capacity payment mechanism is overly generous. The British market BETTA is currently an energy-only market based on bilateral trading; however, BETTA is introducing a capacity payment mechanism because prices have been below the long-run average cost [13], so new capacity has not been forthcoming and a capacity crunch is foreseen. The Nordic market is energy-only based, but each member country has some mechanism to ensure capacity adequacy, e.g., in Finland, some old units receive capacity reserve payments to keep them from being dismantled. There are strategic reserves in Sweden [14] and different types of transmission system operator capacity responsibilities in Denmark and Norway; however, both Norway and Sweden are heavily dependent on comparatively high MC units in neighboring countries. With discussions on additional low MC units and price-decreasing capacity markets in neighboring countries, there is concern regarding ensuring that prices are high enough to cover the costs of all units.

To date, the implementation of the IEM has been concerned with market coupling and capacity allocation across interconnectors. However, capacity remuneration mechanisms, both existing and proposed, in various European Union markets have led ACER to voice opinions on capacity markets [12], [15]. Although ACER does not explicitly recommend against capacity payments, ACER maintains that removing barriers to trade, such as price caps and concessions granted to renewable generators, may remove the need for capacity payments. Further, ACER insists that market integration is the priority, and capacity payments should not distort incentives or trade nor should they cause discrepancies among systems.

The U.S. market areas that have capacity markets include NYISO, ISONE, and PJM. The basic characteristics of these markets are shown in Table 1 below.

TABLE 1. CHARACTERISTICS OF NYISO, ISONE, AND PJM

Market	**Longest Forward Period**	**Longest Commitment Period**	**Demand Curve**	**Auction Product**
ISO-NE	3 years	5 years	Vertical with descending clock auction	Installed capacity (ICAP)
NYISO	30 days	6 months	Downward sloping	Unforced capacity (UCAP)
PJM	3 years	3 years	Downward sloping	Unforced capacity (UCAP)

There is significant interest in the future role of capacity markets in regions that do not currently have them. One example is the Electric Reliability Council of Texas (ERCOT) [16]. FERC recently held a technical workshop on centralized capacity markets [17] that explored and discussed the emerging impact of VG on prices and the potential need for capacity markets.

C. *Locational Marginal Pricing*

VG is often located in remote areas that have poor access to the transmission network, so as renewable generation penetration increases these geographic issues will have more bearing on generation curtailment and electricity prices. Locational marginal pricing (LMP) provides signals for the price of electricity generation at each node in the network, which also incentivizes the efficient use of transmission assets. LMPs feature in many markets in the United States, including PJM, ERCOT, and NYISO.

The European Target model, in contrast, envisages one price for each zone within the European market [11], [18]. This requirement for one clearing price for each zone all but precludes LMP within zones. This may lead to wrong price signals within a particular zone in which transmission constraints do not translate into a dynamic transmission price and cause the scheduled dispatch to diverge from the "optimal" in the case of no transmission constraints. In the single electricity market in Ireland, for example, constraint payments are made to generators for which real-time output as determined by the system operator differs from their scheduled output according to a market dispatch. Total constraint payments made in the years from 2008 to 2012 have been as high as 7% of total system costs [19]. In the absence of a policy shift at the European level in favor of including a location aspect to electricity pricing, it is unlikely that renewable generation can or will be located in an efficient manner in European systems [20].

IV. FUTURE MARKET STRUCTURES

Efficient integration of renewable electricity requires markets that are capable of addressing the specific issues that arise as a result of increased VG. These include the procurement of sufficient flexibility and capacity. Capacity typically involves fixed costs only, so it may be best procured by means of a fixed payment mechanism. Flexibility has both fixed and variable costs, so separate mechanisms are required to procure flexibility both in the short term and the long term.

A. *Short-Term Procurement of Flexibility*

Short-term flexibility could be incentivized through efficient reserve pricing mechanisms. In particular, a reserve pricing mechanism that renders the unit owner indifferent between energy and reserve provision will incentivize the unit to declare its full flexibility in gross pool markets. Inefficient pricing of reserve could lead to generation units either not declaring their full flexibility or entering long-term bilateral contracts with a supply company and limiting the range of their capabilities available to the system operator.

At higher shares of VG, it will become increasingly important to allow VG to participate in reserve provision. VG can provide upward reserve when it is dispatched down. During periods of power surplus, some conventional power plants remain online only to provide reserves. By using surplus VG for reserve provision, conventional units can be shut down, reducing fuel consumption and operational costs. Wind generators can also increase their revenues by acquiring reserve payments as well as energy payments [21].

If VG is allowed to participate in reserve products, it may become beneficial to utilize longer gate closures for reserve products when VG is forecasted to be low and shorter gate closures when VG is forecasted to be high. VG has considerable uncertainty, which decreases with forecast horizon. Moving the gate closure of the reserve products close to real time will decrease energy losses. The trade-off is not to forego cost-effective conventional units by using a gate closure that is too short. One option is to use a combination of longer and shorter gate closures, such as some frequency control reserve that are currently procured in Finland [22].

Uncertainty in demand and generation output levels may lead to a situation in which efficient reserve pricing cannot provide the correct long- and short-term signals [23]. Although stochastic techniques can be used to arrive at an efficient dispatch system, operators have shown a reluctance to rely on these tools without sufficient time to test them. This may lead instead to the specific design of products or payments that reward flexibility [24].

B. Long-Term Procurement of Flexibility

The long-term procurement of flexibility relates to the capabilities of the units. Because both the build times and the lifetimes of generation capacity are significant, there is a premium on certainty, and fixed payments for specific flexible capabilities may be useful. Determining the value of flexible characteristics of generators is a challenge, however, particularly over the long term because the value of the flexibility of a particular unit will depend on the capabilities of all other units on the system. Some possible solutions include procurement of system services by system operators using periodic auctions. This means that the value of flexible capabilities need not be calculated directly. Determining the time frame of such auctions is important. A short time frame may not enable all possible entrants to participate. A longer time frame, however, may lock a system operator into paying for capabilities that would not have been required if the generation portfolio had not evolved as expected.

C. Long-Term Procurement of Capacity

The design of efficient capacity payment mechanisms is nontrivial. Alternatives could include long-term capacity procurement contracts entered into by system operators, in a similar manner to long-term flexibility procurement. However, such long-term agreements can be costly if the underlying assumptions do not play out as expected.

In principle, energy-only markets could provide price signals to invest in capacity, if marginal units are allowed to bid in high prices, taking into account that they need to cover fixed costs with lower operating hours. This would mean that electricity prices would be at times very high and very low. This would incentivize demand-side flexibility, and at least lower the demand for extra capacity payments.

D. Interaction Between Flexibility and Capacity Procurement

A good market design principle is to have a separate product for each requirement in the power system. When a single unit can cater several needs, it follows that the separate products need to be procured simultaneously for optimality. For example, if capacity is acquired with an auction, the auctioneer needs to also consider how much flexibility at different time scales will be required in the future power system and how the auction will reward the flexibility in addition to capacity. This becomes a considerable planning task and may be difficult to implement without distortions. Alternatives at opposite sides of the spectrum include (1) short-term markets only with sufficient rewards for short-term flexibility and (2) monopoly on the asset ownership. The former would require contract markets to enable long-term investments.

Because risks and uncertainties in electricity generation are significant, it may be that there is an incentive on behalf of generators to enter into long-term bilateral contracts with suppliers. This limits the ability of system operators to utilize the full range of flexibility from generators. Thus, a well-designed capacity payment mechanism may reduce uncertainty to generators and increase their incentive to declare short-term flexibility. Alternatively, stochastic optimization of a system may result in efficient price signals that may reduce the need for flexibility payments but will do little to incentivize capacity investment.

A hybrid mechanism that considers unit capability and enables long-term procurement of both flexibility and capacity may prove desirable. However, it is important to note that if such a mechanism can be designed to provide efficient investment signals, then energy and reserve pricing should be limited to ensure that efficient operational signals are provided to avoid double counting and potential market distortion.

There is significant interest in the United States regarding (a) the effectiveness of the existing capacity markets; (b) whether other market areas need capacity markets, given the suppression of prices with high levels of wind/solar energy; and (c) whether long-term capacity markets should include tranches of different flexibility characteristics, whether flexibility and capacity markets should be separate, or whether they should be somehow linked—and, if so, how. In Europe, in principle, the IEM allows different systems to put their own mechanisms in place for the procurement of system services such as flexibility. However, systems that do not include a capacity payment are expected to trade with systems that do, and if the first moves toward an equilibrium whereby price is driven by long-run marginal costs and the latter by short-run marginal costs, this may lead to systematic differentials in price. This may cause inefficient interconnector operation such as that between Finland, which is energy-only for the most part, and Russia, where capacity payments form a large portion of the total generator revenue.

V. Testing Future Market Designs

Testing new market designs is an evolving area of research. As an example, markets in the United States are still changing, as new ancillary service markets are under consideration and as the role of capacity markets is receiving attention from transmission operators and the FERC. Capacity market definitions and structures have changed over the years. For example, in New England the initial capacity market design did not elicit sufficient forward capacity, and redesigns were necessary [14].

In our view, modeling may be a necessary, but not sufficient, condition to ensure that markets will perform as desired. Alternative approaches to help establish market designs include

- production/market simulation
- agent-based market simulation
- analyses of market incentives and potential unintended consequences
- market implementation and evolution

Many production/market models are linearized approximations of reality and thus may not adequately represent the actual operation of markets. This type of market may underestimate the role of agents that wish to maximize profit, and it may also use market characterizations of perfect competition for markets that may more closely resemble monopolistic competition and/or oligopoly. Agent-based simulations can sometimes overcome these limitations, but they may not fully and correctly specify the objective functions of agents. A more abstract analysis of markets and incentives may reveal unintended consequences of market designs. One example is the design of energy markets in much of the United States that ignores the importance of frequency response. These markets provide economic disincentives for generators to provide frequency response because of the structure of the energy markets [24]. Thus, all of the aforementioned approaches, and possibly others, are needed to ensure the proper performance of markets for capacity, flexibility, energy, and ancillary services.

VI. Conclusion

Electricity market evolution is complex and slow moving. In many cases, energy-only markets are being replaced by a combination of energy, ancillary service, and capacity markets, but the interactions among these markets are nontrivial and difficult to predict or model. Capacity markets are attracting interest from the FERC in the United States. In Europe, ACER is openly dubious about the need for capacity remuneration and is concerned about the impact on price signals and trade. Incentivizing capacity without consideration for capability is unlikely to lead to sufficient flexible generation investment, and specific incentives for flexible investment and operation may be required. Although there is certainly a connection between forward capacity markets and flexibility, the specific market mechanisms that will lead to both required long-term capacity and flexibility are as yet unclear.

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