

IFN Working Paper No. 1387, 2021

# **Strategic Reserves versus Market-wide Capacity Mechanisms**

Pär Holmberg and Thomas Tangerås

# Strategic Reserves versus Market-wide Capacity Mechanisms<sup>a</sup>

Pär Holmberg<sup>b</sup> and Thomas Tangerås<sup>c</sup>

April 2, 2021

## Abstract

Many electricity markets use capacity mechanisms to support generation owners. Capacity payments can mitigate imperfections associated with “missing money” in the spot market and solve transitory capacity shortages caused by investment cycles, regulatory changes, or technology shifts. We discuss capacity mechanisms used in different electricity markets around the world. We argue that strategic reserves, if correctly designed, are likely to be more efficient than market-wide capacity mechanisms. This is especially so in electricity markets that rely on substantial amounts of intermittent generation, hydro power, and energy storage whose available capacity varies with circumstances and is difficult to estimate.

**JEL codes:** D25, D47, Q40, Q48

**Keywords:** Capacity mechanism, market design, reliability, resource efficiency

---

<sup>a</sup> This work has been financially supported by the Swedish Energy Agency and Svenskt Näringsliv. We are grateful for comments at meetings with Svenskt Näringsliv, Svenska Kraftnät, Energiforsk, and the reference group of the project 46227-1 of the Swedish Energy Agency. In particular, we would like to thank Zarah Andersson, Peter Cramton, Björn Hagman, Lina Håkansdotter, Marie Knutsen-Öy, Malgorzata Sadowska, and an anonymous referee for help and comments on our work. Finally, we want to thank Glenn Nielsen, who assisted us when writing this paper.

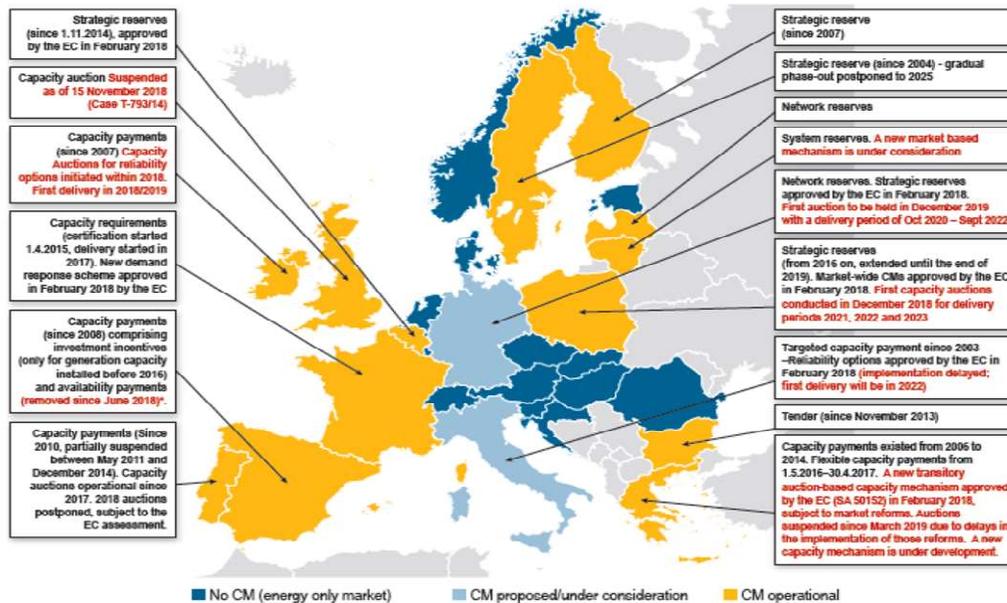
<sup>b</sup> Research Institute of Industrial Economics (IFN), Stockholm. Associate Researcher of the Energy Policy Research Group (EPRG), University of Cambridge. Affiliated with the Program on Energy and Sustainable Development (PESD), Stanford University.

<sup>c</sup> Research Institute of Industrial Economics (IFN), Stockholm. Associate Researcher of the Energy Policy Research Group (EPRG), University of Cambridge. Affiliated with the Program on Energy and Sustainable Development (PESD), Stanford University.

# 1 Introduction

Deregulated wholesale electricity markets have a spot market in which consumers pay producers for the electricity they deliver. In *energy-only* markets, such as Denmark, the Netherlands, Norway and Texas, this is the only payment producers earn in the wholesale market. In many other markets, producers receive an additional upfront payment for making capacity available to the market. In Belgium, Finland, Germany and Sweden, such *capacity payments* are limited to generation units within a selected *strategic reserve*. But in the UK and in most deregulated electricity markets in the US, all generation units receive capacity payments. We refer to such a market-wide capacity mechanism as a *capacity market*. One can roughly divide capacity markets into volume-based and price-based mechanisms. In a volume-based capacity market, as in the UK, the total volume of generation capacity is predetermined, and the capacity price is determined in an auction for the demanded volume. In a price-based capacity market, it is instead the price that is predetermined, and the procured volume is determined by the supply of capacity. Figure 1 gives an overview of the capacity-market designs that are used in the EU.

Figure 1. Electricity markets in the EU



Source: Acer (2019).

According to economic theory, capacity mechanisms are redundant in a competitive and well-functioning energy-only market. If an energy-only market fails to provide sufficient investment, one can simply increase the price cap up to the level at which consumers would rather prefer to be curtailed. This price is known as the Value of Lost Load (VOLL). The energy-only design therefore is the natural first choice for a deregulated electricity market. If further investment incentives are needed, Wolak (2021) recommends that it should be

obligatory for retailers to buy forecasted demand in the forward market, which would also mitigate market power. But a high price cap and/or regulated forward trading is not always politically acceptable. The missing money problem that arises because of insufficient price caps, may require capacity mechanisms to ensure sufficient investment incentives (Cramton et al. 2013; Léautier, 2019). Other reasons why authorities may introduce capacity mechanisms are long times in building capacity, so that temporary capacity shortages can occur due to investment cycles, new regulations, and technology shifts. Hence, the government may have an interest in controlling the production capacity in the market. According to Wolak (2004), capacity markets also have a historical explanation. Prior to deregulation in US, similar payments were used to compensate generation owners for their fixed costs.

Holmberg and Ritz (2020) note that well-designed strategic reserves and capacity markets are as efficient as an energy-only market in a simplified market where ramping costs, intermittency, elastic demand, imperfect competition, and imperfect information are negligible. However, modern markets with non-thermal technologies, such as energy storage, demand response and renewables with intermittent output are more complicated. Many capacity mechanisms struggle with technologies for which it is hard to estimate firm capacity; a generation unit's reliable output, and to give them correct price signals. As an example, a capacity market does not give the right incentives to wind power owners, when they choose plant location, plant design and how to maintain the plan and prepare it for extreme weather conditions. The latter has turned out to be of particular importance in the US, where capacity tends to become unavailable when it is most needed, during extreme weather conditions. Another problem is how to give correct price signals to energy storage (including hydro power), so that they save optimally for critical days, if prices are capped at a level below VOLL. We argue that a well-designed strategic reserve is likely to be more efficient than a capacity market, especially when a substantial amount of power is produced by renewables and/or hydro power. In addition, for a well-designed strategic reserve, the procurement of capacity would be more competitive than for a capacity market, which procures a much larger volume.

Holmberg and Ritz (2020) outline how a strategic reserve should be designed. A well-designed strategic reserve is isolated from the rest of the market, which can then rely on the energy-only principle, which gives the right price signals. One advantage with this design is that it is only necessary to define firm capacity for the units within the reserve. This is often straightforward because the reserve would mostly consist of thermal peak-load units with high variable costs. The advantages of a strategic reserve are particularly large for Sweden and other countries where hydro power plays a big role. We discuss the market design of the Swedish strategic reserve in detail, which has several similarities with reserves in Belgium, Finland and Germany. The procurement and activation of the Swedish reserve is mostly well-designed, but we also discuss some remaining issues.

One problem with strategic reserves is how to manage demand response. In Sweden, the most straightforward solution to this problem would probably be to stop procuring demand response for the strategic reserve and instead to allocate this capacity to ancillary services. Demand response is often fast but with limited endurance, which should make it more

suitable for ancillary services than the strategic reserve. In Sweden, demand response within the strategic reserve is already activated in one of the ancillary-service markets (Reglerkraftmarknaden), so our tentative suggestion should not be a big step.

Another problem with strategic reserves is that markets tend to have unnecessarily restrictive rules for plants in the reserve. For example, in Belgium and Germany a plant that has entered the reserve can never return to the market. Moreover, in Germany the plant must close after some years in the reserve. We favor an isolated reserve, but we think that Belgium and Germany have exaggerated this issue. Sweden has stricter environmental rules for plants in the reserve than for plants outside the reserve. Such restrictive rules are inefficient from a resource adequacy perspective and they probably also worsen competition in the procurement of the reserve.

In the paper, we also discuss aspects of capacity procurement considering the experience from Europe, the US and South America. Marginal pricing would normally be the first choice, but has not worked particularly well in capacity procurement, where prices sometimes become very high. In that case, alternative designs such as pay-as-bid should be better for consumers and for efficiency. Other questions to consider are: (i) who will be responsible for procuring the capacity; (ii) how much information should bidders receive during the procurement process; (iii) how far in advance should capacity be procured? For instance, competition is often better if capacity is procured well in advance before the capacity is needed because entry barriers are lower when firms can expand capacity after the auction. However, more information is available, for example regarding the availability of plants, if the procurement is done close to delivery. This can be an advantage for technologies where available capacity is difficult to estimate long in advance, such as energy storage and demand response. This is a reason why the procurement of capacity to ancillary services, where such technologies are particularly useful, should preferably be done close to delivery.

This paper focuses on resource adequacy, i.e., how capacity mechanisms can be used to support the wholesale market. Some targeted capacity mechanisms, such as targeted capacity payments or tenders for new capacity, are useful when solving specific problems, such as supporting renewables, facilitating the closure of coal plants, and strengthening ancillary services.<sup>1</sup>

The paper is outlined as follows. Section 2 gives a quick introduction to electricity markets in the EU and the US.<sup>2</sup> In Sections 3 and 4, we briefly discuss investments by a central planner and reiterate well-known results for investments in a competitive energy-only market. In Section 5 we go through capacity markets in detail and how capacity can be procured. In Section 6, we discuss strategic reserves, with a particular focus on the Swedish strategic reserve. We conclude in Section 7.

---

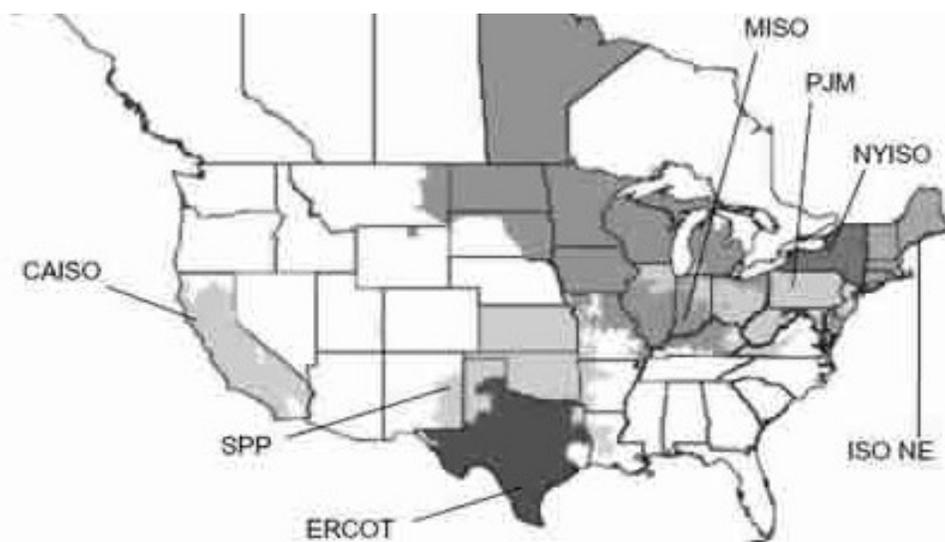
<sup>1</sup> See the survey by Bublitz et al. (2019) and references therein for thorough discussions of targeted capacity payments and tenders for new capacity.

<sup>2</sup> A more detailed comparison of US and European electricity markets can be found in Ahlqvist et al. (2018). That report emphasizes the advantages and disadvantages of centralized electricity markets.

## 2 Electricity markets in the EU and the US

The EU internal electricity market is divided into price zones, mostly one per country. The amount of consumption and production within each zone is cleared on the spot market, accounting for the transmission capacity between zones. Intra-zonal constraints are generally neglected in the spot market.<sup>3</sup> In most EU countries, producers can decide which of its units will produce the contracted amount of electricity within each zone. This is usually called a decentralized or portfolio-oriented spot market. In Europe, the system operator often owns the transmission system. Hence, TSOs (transmission system operators) receive congestion revenues when price differences arise between zones. This means that their revenue depends on the spot market outcome. This is one reason why the spot market often has been managed by a market operator (not by the system operator) in EU countries. In European electricity markets, retail is unbundled from distribution.

Figure 2 Seven deregulated electricity markets in the USA



All states have substantial autonomy over the design of their electricity markets in the US. For example, several states have decided not to deregulate their markets. Figure 2 shows the geographical footprint of the seven deregulated electricity markets particularly relevant to this study: California (CAISO), Midcontinent Independent System Operator (MISO), New England (ISO NE), New York (NYISO), Pennsylvania-New Jersey-Maryland (PJM), Southwest Power Pool (SPP) and Texas (ERCOT). MISO, ISONE, PJM and SPP each span several states. MISO also includes Manitoba in Canada. CAISO, NYISO and ERCOT are within-state markets. ERCOT in Texas is an exception, but currently the other six electricity markets in US have designs inspired by the standard design recommended by the Federal Energy Regulatory Commission (FERC). Capacity markets are part of that standard design.

<sup>3</sup> For the Net-Transfer-Capacity (NTC) approach all intra-zonal congestion is neglected in the spot market, while some critical intra-zonal lines can be considered in the flow-based approach. NTC is still used in the Nordic countries, but most of Europe is moving towards flow-based zonal pricing.

Another aspect of the standard design is a centralized spot market in the sense that the system operator decides how much is to be produced by each unit. These decisions are based on the detailed bids at the unit level submitted by generation owners. In the US markets, the system operator is an Independent System Operator (ISO). The ISO owns no network capacity nor any generation capacity to generate revenue on the spot market. This independence means that it is unproblematic for the system operator to be involved in the procurement of production capacity and the operation of the spot market. In the US, sales and distribution of electricity are often integrated into Load Serving Entities (LSEs). The final customer prices are often regulated.

In this paper, we will also discuss some markets in South America that use capacity markets. Colombia is one particularly interesting example. It should be noted that South American markets often differ from EU and US markets in that they are heavily regulated. For example, South American electricity markets are often cost-based, meaning that producers are not allowed to submit bids to the market (Ahlqvist et al., 2018).

### 3 Investments by a central planner

In an efficient electricity market, electricity is produced at the lowest possible total production and investment cost. Capacity utilization will be very different for different plants because of fluctuating demand across the day and the year. Some plants run almost all the time, and others are rarely used. Therefore, it is usually efficient to invest in a mixture of different technologies, where the choice of technology for a specific plant depends on how often the plant is to be used. Typically, low variable-cost technologies have a high investment cost, and vice versa. For base load units that are active almost all the time, it is efficient to utilize economies of scale in production. These are technologies with low variable costs and high fixed costs, such as nuclear power and hydro power where available. As the utilization rate decreases, it becomes more important that the plant does not cost money when not in use. It will then be more economically profitable to use technologies with higher variable costs and lower fixed costs. Some peak-power plants are used only a few times a year. These have very high variable costs and low fixed costs. To optimize investments, the social planner needs to get both the volume of investments and the right mixture of technologies right.

### 4 Investments in an energy-only market

Investments in electricity markets are often analyzed under ideal assumptions, which we refer to as a simplified electricity market.<sup>4</sup>

**Definition** *A simplified electricity market has perfect competition, free entry, quick entry/exit of capacity, no network congestion, price-insensitive demand, no risk of a total system collapse, risk-neutral investors, fully informed agents, and only flexible and enduring production that is always online.*

---

<sup>4</sup> It is possible to analyze investments under more general assumptions. For example, Joskow and Tirole (2007), Tangerås (2018) and Astier and Lambin (2019) allow elastic demand. Zöttl (2010) considers imperfect competition, and Teirilä and Ritz (2019) simulate strategic investments in the Irish market.

We use the term *enduring* to denote production that does not run out of fuel. Hydro-power and other energy storage is not enduring. In the short term, price-insensitive demand is a reasonable approximation. The main reason is that most customers buy electricity on long-term supply contracts and therefore have little to gain from reducing consumption in resource-constrained situations. But this does not mean that customers would be willing to consume electricity at *any* price. *Value of Lost Load* (VOLL) denotes the theoretical price at which an average customer would rather be disconnected than continue to use electricity. We denote this price by  $p_{VOLL}$ . We let  $\bar{c}$  be the highest variable cost to produce one kilowatt (kW) of electricity on the market and  $k(\bar{c})$  be the fixed cost per kW of capacity for this plant. If demand exceeds the total capacity in the market, there will be a shortage of electricity, and it will be necessary to ration demand to avoid blackout. Investing into an additional (marginal) plant helps to reduce the electricity shortage. The socio-economic value of producing one kW of electricity in this plant when there is shortage is given by the difference  $p_{VOLL} - \bar{c}$ . The probability of power shortage is usually referred to as *Loss of Load Probability* (LOLP). If we state this probability for a year as  $\pi_{LOLP}$ , it is socio-economically profitable to invest in new capacity if the expected value  $\pi_{LOLP}(p_{VOLL} - \bar{c})$  of the most expensive plant exceeds its fixed annualized cost  $k(\bar{c})$ .<sup>5</sup>

**Conclusion** *Investments in a simplified electricity market are efficient if the total production and investment costs are minimized for each plant, taking into account their degree of utilization, and if the highest variable cost on the market meets the relationship  $\pi_{LOLP}(p_{VOLL} - \bar{c}) = k(\bar{c})$ .*

From the conclusion above it is evident that a positive likelihood of curtailment is efficient as long as consumers' willingness to pay to avoid power shortages is bounded. In other words, it is not economically viable to have such extensive investments that the risk of rolling blackouts disappears completely. Optimizing the duration of blackouts is called the adequacy problem (Cramton et al., 2013). The heart of the adequacy problem is resolving the trade-off between more capacity and more blackouts.

For producers operating in a competitive market, it is profitable to cut costs and minimize the total cost of production and investment for each plant, considering its capacity factor. In situations of excess demand, the most expensive plant on the market receives the revenue of  $\bar{p} - \bar{c}$ , where  $\bar{p}$  is the price cap in the spot market. It is profitable to invest in additional peak power if the expected profit  $\pi_{LOLP}(\bar{p} - \bar{c})$  in the spot market exceeds the annualized investment cost  $k(\bar{c})$ . In a market with perfect competition, and free entry, companies will invest until the marginal invested dollar becomes unprofitable. Based on this reasoning and the conclusion above, we can draw the following conclusion:<sup>6</sup>

---

<sup>5</sup> This approach is called *peak-load pricing*, or *screening curve analysis* (Chao, 1983; Crew and Kleindorfer, 1976; Stoft, 2002; Biggar and Hesamzadeh, 2014; Léautier, 2019).

<sup>6</sup> This is a standard result that can be found in for example Stoft (2002), Joskow and Tirole (2007), Léautier (2019) and Willems (2015).

**Conclusion** *The investments will be efficient in a simplified electricity market if the price cap is chosen so that  $\bar{p} = p_{VOLL}$ .*

An energy-only market will thus be efficient and provide the investments the market needs if the system operator rations consumers at the  $p_{VOLL}$  when there is a shortage of electricity. A simplified market with a price cap at  $p_{VOLL}$  does not favor any technology; investments will be optimal for all technologies on the market.

## 5 Capacity markets

### 5.1 Why capacity markets?

A consequence of the results in the previous section is that an energy-only market will fail to deliver efficient investments in a simplified electricity market if the price cap  $\bar{p}$  deviates from  $p_{VOLL}$ . If the price cap is set too low, then electricity shortage will occur too often because there will not be enough investment. There are several reasons why the price cap is sometimes set below  $p_{VOLL}$ . One reason is that it is a way of mitigating market power. Holmberg and Newbery (2010) show that a small price cap pushes down the entire supply curve in markets with imperfect competition. Thus, it is not just that price spikes are cut, but the price decreases during all hours of the day. A lower price cap also reduces price risks in the market. This is a particularly important aspect in countries that lack well-developed financial trade. In well-developed markets on the other hand, producers, electricity traders and consumers should have better opportunities to use financial contracts to hedge prices (Tangerås, 2018).

A third reason is that high electricity prices can become difficult to handle politically. Political pressure reduces the market's confidence that a formally established price cap will prevail in situations of power shortage. Léautier (2019) argues that, from a political perspective, there may be advantages in setting a lower price cap than is socially optimal and ensuring security of supply through capacity payments.

**Conclusion** *Market power, price risk and political considerations can motivate a price cap below  $p_{VOLL}$ . Capacity markets then become a way to maintain resource adequacy.*

Cramton et al. (2013) argue that  $p_{VOLL}$  is so difficult to measure that it will be incorrect to let the price cap drive investments in the market. Instead, they advocate that authorities set a target for reliability measured by the probability  $\pi_{LOLP}$  for power shortages and that they procure the corresponding capacity to ensure that there is sufficient capacity. Calculating reliability is a difficult task, but one that engineers have decades of experience with, since regulated utilities use essentially the same approach to decide how much capacity to build (Cramton et al., 2013). Léautier (2019) is somewhat skeptical to that reasoning, as it is unclear which level of  $\pi_{LOLP}$  is efficient. It will also be a major market intervention to start from  $\pi_{LOLP}$ , as the authorities need to estimate consumer demand, instead of leaving this process to the market.

A risk of energy-only markets is that capacity shortage can occur due to investment cycles, sudden technological change, or sudden changes in regulations (Spess et al., 2013). This means that the market will deviate from its equilibrium in the short term and that the risk of electricity shortages might significantly increase. Arango and Larsen (2011) summarize the literature on boom-bust cycles. Those are mainly a problem in capital-intensive industries with long construction delays and can occur when investors are imperfectly informed and act myopically, i.e. they mainly invest when commodity prices are high. Various papers have identified boom-bust cycles in the mining, oil, pulp, paper, chemical and real-estate industries (Arango and Larsen, 2011). Arango and Larsen (2011) study investment cycles in the three electricity markets with the longest history: Chile, Nord Pool and UK. In UK and Chile, the variations in the reserve margin are pronounced and consistent with boom-bust cycles. The cyclic pattern is less prevalent in the Nordic countries. Arango and Larsen (2011) argue that the reason for this could be that the dominant producers in the Nordic countries are controlled by the government and that these companies have a longer perspective.

Electricity shortages can occur due to sudden changes in regulation. Newell et al. (2012) describe an episode where market participants in ERCOT (Texas) were concerned that new environmental legislation could lead to a substantial amount of plant closures. An example from Sweden was the government's proposal for a new tax on waste incineration, which prompted electricity producers to announce the closure of critical electricity production in Stockholm and other metropolitan areas. Another example was safety directives regarding passive cooling of nuclear power plants, which in combination with the tax on nuclear power and low prices, contributed to the decisions to shut down reactors prematurely in Sweden. Deviations from the market equilibrium and the risk of electricity shortages will be lower if regulatory changes are announced well in advance. Disequilibrium could also occur if the market undergoes a rapid transformation in a short time, for example after a technology shift. Volume-based capacity markets should be particularly suitable for controlling market capacity and counteracting abrupt changes as well as investment cycles.

**Conclusion** *Investment cycles, new regulations and technology shifts can lead to temporary shortage of production capacity in an energy-only market. Capacity markets can counteract abrupt changes and coordinate investments.*

Capacity markets can also increase the margin in the system, and thus provide more scope for short-term deviations from the long-term market equilibrium, without leading to a significant risk of electricity shortages during an energy transition.

Positive external effects on the electricity market can also motivate a capacity market, or to set the price cap above VOLL. When demand is so high that there is a shortage of electricity or a significant risk of shortage of electricity, the margins in the electricity system become small. The risk for an uncontrolled system collapse increases, whereby all or large parts of the market are shut down for several hours (Joskow and Tirole, 2007; Cramton et al., 2013). Consumers and producers have much to lose from such a collapse. The risk of power shortages decreases if the available capacity increases, so that the probability of a system collapse decreases. Security of supply, and more generally, the quality of delivered electricity

in terms of low risk of interruption, stable voltage level and stable frequency is a public good (Abbot, 2001; Amundsen and Bergman, 2007). Hence, each new investment in production capacity has positive external effects that benefit all agents in the electricity system (Fabra, 2018; Llobet and Padilla, 2018). To obtain optimal investments regarding this type of positive external effect, payments to producers need to be increased. A higher price cap can be a way to achieve this objective. A different possibility is to increase capacity payments.

Another argument that is sometimes used to justify capacity markets is that subsidies for renewable electricity production displace thermal electricity production. In part, this type of argument is put forward by producers who have lost revenue from the displacement and who want compensation for this. But displacement can also be a societal problem if one wishes to maintain thermal capacity as a complement to renewable production, as in Portugal and Spain (Roques and Verhaeghe, 2015).

## 5.2 Problems with capacity markets

In practice, procured capacity tends to be too large, perhaps due to excessive risk aversion of political decision makers. Cramton and Stoft (2008) argue that the cost of an overinvestment in production capacity does not have to be particularly large. They estimate that a capacity that is 10 % larger than what is socially optimal increases the cost to consumers by about 2 % and the cost to society by around 1%. However, estimates by the American Public Power Association (APPA) suggest that costs could be higher. They estimate that an average household in PJM's area pays \$120 extra per year to cover capacity payments (APPA, 2017). Nelder (2013) argues that the authorities in Australia have been poor at estimating demand. The problem has been noticeable, for example, in Western Australia, where a capacity market gave rise to large over-investments resulting from an unexpected fall in electricity demand. Nelder (2013) further believes that there are similar problems in the United States. Newbery (1997) shows that the authorities systematically overestimated the risk of electricity shortages in England and Wales in the 1990s. Capacity payments were proportional to  $\pi_{LOLP}$  during that period, so the result was excessively large capacity payments in that region. Newbery and Grubb (2014) argue that the new capacity market in the UK is likely to result in excessive procurement of capacity, mainly because the contribution from interconnectors is neglected.

Availability is another issue with capacity markets. A plant that has received a capacity payment is obliged to provide its firm capacity when called upon by the system operator. But regulations sometimes allow circumstances under which a facility does not have to be available. A potential problem then is that the owner may take advantage of such exemptions. This has been a problem in electricity markets in North and South America, where producers have managed to get capacity payments for facilities that were unavailable. It is therefore important that a capacity market is careful when defining what it means that capacity should be available, and that the regulations leave minimal room for manipulation of availability. In addition, producers should have particularly strong incentives to supply capacity where one can predict in advance that the demand for electricity will be particularly high (Batlle et al., 2015). Unfortunately, performance is often at its worst under extreme conditions when capacity is needed the most. PJM lost more than 20% of its capacity during a cold period in

January 2014 (Rose et al., 2014). A third of the lost capacity in PJM was natural-gas generation with interruptible-gas contracts, which could not get any gas delivered. Texas had similar issues during the electricity crisis in 2021, which was caused by a winter storm. As illustrated during the rolling-black-out events in California in mid-August 2020, extremely high temperatures can also be a problem for natural gas. Production efficiency goes down with the ambient temperature and California lost 1400 MW-2000 MW gas capacity during the heat storm (CAISO, 2020). There was a similar issue with solar power, which also becomes less efficient at high temperatures. Nearly 20% of the solar capacity disappeared which also contributed to the rolling black outs.<sup>7</sup> The extreme weather events have shown that it is important that natural gas plants receiving capacity payments should be required to have non-interruptible gas contracts and/or being able to switch to a back-up fuel (Rose et al., 2014), and PJM has tightened its capacity requirements (Batlle et al., 2015). The downside is that some capacity is excluded from, or disadvantaged in, the capacity market.<sup>8</sup> The consumer side argues that the stricter requirements have led to higher prices in the capacity market (APPA, 2017). Availability requirements, and how deviations from these should be punished, are tricky issues for capacity markets.

*Reliability options* were launched as a possible solution to parts of the availability problem and are for example discussed by Cramton et al. (2013). For this type of capacity market, producers must issue options corresponding to the capacity planned to be available on the market. The options have a strike price corresponding to the highest variable cost on the market. If the spot price exceeds the strike price, producers must pay the difference, so that the consumer price will never exceed the strike price. The producers are paid to issue the options, which is partly a compensation for providing the hedge, but it also constitutes a capacity payment. The undertaking is unproblematic for the producer provided its plants are available. In case of high spot prices, a producer's revenue from the spot market can be used to pay the consumer, in accordance with the option contract. This gives producers incentives to try to keep capacity available, especially when the price is high, and capacity is needed most. Reliability options have for instance been applied in Colombia. A problem there is that the country also introduced a so-called administrative price cap on the option's strike price. The purpose was to keep prices down and to reduce the risk in the market, but an unforeseen side effect was that electricity producers with a dominant position were given stronger incentives to raise the price above the strike price. McRae and Wolak (2019) study this problem empirically and show that the side effect has led to higher electricity prices and reduced availability in Colombia. Colombia's electricity market could be particularly challenging. Shortages of electricity tend to be rare, but persistent once they occur. Still there is a risk that similar problems could arise in Ireland and New England, which use a similar capacity-market design.

---

<sup>7</sup> This was mentioned in the presentation "Evidence from California on Challenges Facing Electricity Supply Industries with a Significant Share of Intermittent Renewables" at the meeting of the Swedish Association of Energy Economists (SEEF) on September 24, 2020.

<sup>8</sup> Capacity payments have led to many controversies in the US, where different owners, for example, have argued that they have been disadvantaged by various rule changes. Regulatory changes in the capacity market are often settled through litigation (Spees et al., 2013; APPA, 2017).

Another question is whether different technologies should be procured in the same auction. Experience from PJM suggests that simultaneous procurement increases competition and auction efficiency. However, different technologies often have different availabilities. A collective procurement therefore presupposes that it is possible to calculate firm capacity for technologies with lower availability. However, this is easier said than done, especially as it is not only the physical availability that matters but also the time when a plant is available. Weather-dependent renewable electricity production, for example, is more valuable if it covaries with demand and delivers as much as possible when the risk of electricity shortage is greatest. The location, design, and maintenance of (including ice removal) a wind power plant can all have a significant impact on how much it can produce when there is an electricity shortage. The problem with derating factors is that they would generally not give the right incentives to wind-power owners for these, and related, decisions. It is also tricky to define a firm capacity for hydro power. How should one give correct price signals to energy storage (including hydro power), so that they save optimally for critical days, if prices are capped at a level below  $p_{VOLL}$ ? Wolak (2019) provides several examples from hydro-power-dominant markets in Latin America where the firm capacity for hydropower was overestimated, so that the procured capacity could not deliver as planned. Wolak (2019) also makes the point that it is rarely the physical capacity that is the problem in hydro power dominated markets. The problem is energy shortages occurring in dry years. Capacity markets are therefore more suitable for markets dominated by thermal production, which is more enduring.

A small price cap reduces consumers' interest in demand response. To a certain extent, this can be compensated if demand response is rewarded with a capacity payment. Even in such cases, it can be difficult to define a firm capacity and to regulate availability. For example, should the consumer be required to always use more than a certain amount of electricity to ensure that there is always enough capacity to reduce consumption? As mentioned above, similar problems exist when defining a firm capacity for energy storage.

**Conclusion** *A problem with capacity markets is the difficulty of defining firm capacity to provide correct price signals for non-thermal technologies such as solar power, wind power, demand response, hydro power and other energy storages.*

The reliability externality (Wolak, 2019 and 2021) is another issue with low price caps. The problem is that consumers of a retailer/LSE that has bought electricity in advance are as likely as consumers of a non-contracted retailer/LSE to be disconnected in case there is an electricity shortage. As contracting does not give priority in such situations, retailers/LSEs will buy too little electricity in the forward market. This effect is particularly noticeable in markets with low price caps, such as in Latin America (Wolak, 2019). If a regulatory intervention is required to fix this problem, then Wolak (2019; 2021) recommends mandatory forward contracting. In some of the countries in Latin America, retailers/LSEs are required to purchase up to 90 % of their clients' planned consumption one or more years in advance.

Capacity markets need an authority to verify firm capacity, which could be a cumbersome bureaucratic process. There is therefore a risk that capacity markets benefit large owners at the expense of smaller owners, such as households and small industries that have invested in

solar panels, wind power, demand response or energy storage. A market-wide capacity market is probably more suitable for centralized markets such as in the US, where all capacity, including demand response and energy storage, must be verified anyway and approved before it can participate in the spot market (Ahlqvist et al., 2018). In decentralized electricity markets, such as in Europe, retailers can use historical data to estimate demand response, local production and storage of their customers and bid a corresponding demand curve to the spot market. An advantage of a decentralized market is that small-scale production, energy storage and demand flexibility does not need to be approved and verified.

**Conclusion** *A problem with capacity markets is that the firm capacity of all facilities, small and large, must be verified and approved. This bureaucratic process disadvantages small agents and makes the market design administratively costly.*

### **5.3 How do capacity payments and the price cap affect investment?**

The spot price often clears above the variable cost of base-load power. Hence, revenue from the spot market contributes to covering the large, fixed costs of base load. As a consequence, a large fraction of the revenue that base-load receives in excess of its variable cost is independent of the price cap and capacity payments. It is different for peak power. In a competitive market, the spot price covers little else than its variable cost under normal system conditions. However, the electricity price increases to the level of the price cap under a power shortage, during which, peak power receives a scarcity rent that can be used to finance the investment costs. For this reason, peak power is particularly dependent on price caps and capacity payments.

In the short term, all plants benefit from a sudden introduction of or increase in capacity payments, but there will be new investments so that capacity increases. This reduces the risk of electricity shortages, which reduces the revenue for old plants. In a simplified electricity market, the reduced revenue corresponds exactly to the increase in capacity payment (Holmberg and Ritz, 2019). Hence, in the long run nothing happens to the capacity of existing technologies for a simplified market in equilibrium. In the long term, an increase in capacity payments will entirely go to financing investments in new plants, which will have a higher variable cost than the old facilities. The consequence will be the same if the price cap is raised. Conversely, only the capacity of the peak power will decrease in the long term if capacity payments or price caps are lowered.

**Conclusion** *In the long run, only the capacity of the peak power is affected by the level of capacity payments and price caps, at least in a simplified electricity market.*

This is also an argument for why new and old plants should receive the same capacity payment. In addition, there is a risk that the agents will try to take ineffective measures if the capacity market discriminates between new and old capacity. There are several such examples from related markets. In Sweden's market for tradable green certificates, only capacity below a certain age is entitled to compensation. One consequence of this was that wind power was scrapped prematurely (Mauritzen, 2014), and that old hydropower was rebuilt to appear as new. PJM, NYISO and ISO-NE make no distinction between new and old capacity, while

such differences exist in California (Spees et al., 2013) and have been suggested for the German market (Öko-Institut et al., 2012).

**Conclusion** *A capacity payment should not differentiate between new and old capacity.*

## 5.4 How large should the capacity payments be?

Let  $\pi_{LOLP}^*$  be the efficient probability of curtailment, which corresponds to some total market capacity  $q^*$ . Let  $p^*$  be the capacity payment, which is determined by the market, when  $q^*$  is procured. We refer to this solution as the efficient capacity payment. Holmberg and Ritz (2019) argue that for a simplified electricity market, it does not matter whether the operator procures the volume  $q^*$  or sets a predetermined capacity payment  $p^*$ , the outcome will be the same. Holmberg and Ritz (2019) calculate combinations of price caps and market-wide capacity payments that yield efficient investments in a simplified electricity market. The efficient capacity payment in a simplified electricity market equals  $\pi_{LOLP}(p_{VOLL} - \bar{p})$ . With this capacity payment, the sum of the capacity payment and the expected scarcity rent will be independent of the price cap and equal to  $\pi_{LOLP}(p_{VOLL} - \bar{c})$  for the marginal unit, which ensures efficient investment incentives.

**Conclusion** *In a simplified electricity market, the socially optimal market-wide capacity payment is  $\pi_{LOLP}(p_{VOLL} - \bar{p})$ .*

It is difficult to give producers incentives to run plants for which the marginal cost is above the price cap.<sup>9</sup> Hence, a price cap below  $\bar{c}$ , the highest variable cost for which investment is efficient, would most likely lead to inefficiencies. Holmberg and Ritz (2019) estimate that  $\bar{c}$  is roughly 50-75 % of  $p_{VOLL}$ . This rough calculation indicates that the price cap should not be set far below  $p_{VOLL}$  if one wants to avoid inefficient investment.

## 5.5 Intermittent power and ramp rates

Holmberg and Ritz (2019) study what happens in an otherwise simplified electricity market when the share of renewable electricity increases. They find that the risk for electricity shortage stays constant if price caps and capacity payments remain unchanged. However, there will be a switch from thermal base load to thermal peak load as more renewables enter the system. In the short term, such a change can probably cause increased risk of electricity shortage, for example related to non-coordinated plant closures and investments.

**Conclusion** *In the long run, additional renewables do not increase the risk of electricity shortages in a simplified electricity market. However, it changes the optimal technology mix, and this readjustment can lead to temporary capacity shortages.*

If the delivery periods are sufficiently short that fluctuations in electricity prices internalize the system effects of fluctuations in renewable electricity production, then investments would be efficient also in the presence of intermittent generation and ramping costs in an energy-

---

<sup>9</sup> Lambin (2020) claims that it would be possible to achieve this outcome using tailor-made contracts.

only market where the price cap is set at  $p_{VOLL}$ . In that case, capacity markets would not generally yield efficient investment in such technologies, even if capacity payments would follow the relation  $\pi_{LOLP}(p_{VOLL} - \bar{p})$ . The problem is that a lower price cap and a higher capacity payment reduce price fluctuations in the electricity market. This is bad for flexible production with short ramping times and low ramping costs that would benefit from price fluctuations, and it benefits intermittent production that would otherwise have been negatively affected by these price fluctuations.

**Conclusion** *Market-wide capacity markets, in combination with a lower price cap, reduce price fluctuations. This distortion favors intermittent production and disfavors flexible production and energy storage.*

In practice, intermittent output from renewables is a challenge for the system. Holmberg and Ritz (2019) argue that the risk of a stressed situation evolving into a total system collapse increases with more wind power in the system. Hence, the security-of-supply externality will also increase. Newbery (2020) analyses externalities related to wind power in detail and derives an annual charge/subsidy that would correct the externality.

## 5.6 What is the demand for capacity?

For a simplified electricity market, it does not matter if the procurement of capacity is done according to a predetermined price or a predetermined volume if the price and volume ultimately remain the same. In practice however, capacity markets are not so simple, and thus the design of the procurement plays a greater role.

Many capacity markets are neither price- nor volume-based, but something in between where the procurement takes place along a specified demand curve. In Italy, the system operator Terna has designed a value-based demand for capacity that is calculated based on the estimated value of this capacity to consumers. In the US, however, many experts find it as difficult to estimate consumers' valuation of capacity as it is to estimate VOLL. Decision-makers fear that valuation-based demand will give too low reliability. Nevertheless, many markets in the US have chosen to make procured capacity dependent on capacity payments. These demand curves are not based on a valuation of capacity, but have been designed to, among other things, reduce price volatility and to reduce the market participants' opportunities to exercise market power when capacity is being procured.

Price volatility in the capacity market is one of the biggest problems facing suppliers of capacity (Spees et al., 2013). To reduce the risk of investors, it has been suggested that the demand curve for capacity should be convex (Hobbs et al., 2005, 2007; Stoft et al., 2004, 2005). By implication capacity payments would be relatively large even if the supply of capacity is large, and the procured capacity will be relatively large even if the capacity price is high. ISO-NE has a demand curve that is reminiscent of this form, although they allow the procured capacity to be low if the price of capacity is very high. The design of ISO-NE's capacity market stabilizes prices, but it also leads to significant inefficiencies (Spees et al., 2013). In addition, consumers do not necessarily value such price stability. If new capacity is

willing to enter the market even at small capacity payments, then this should have an effect on prices, according to the consumer side (APPA, 2017).

All capacity markets we know of have a reservation price. This means that in practice the demand for capacity is partly concave, at least at high prices. This corresponds to the procurer wanting to protect the consumer side against very high prices.

## **5.7 How should capacity prices be set?**

Capacity markets normally use marginal pricing, pay-as-bid or so-called Vickrey pricing. In a simplified electricity market, the outcome and the costs for consumers will be the same regardless which of these price mechanisms is used. This is approximately the case also in practice for electricity spot markets and treasury auctions, where competition is reasonably well functioning (Holmberg and Newbery, 2010).

But imperfect competition is a major problem for many capacity markets. The underlying problem is that if the procurer wants to buy almost all existing capacity in the market, then a seller can push the price to the price cap by withholding a fraction of its volume from the market. Under these problematic circumstances it matters how the price is set.

Marginal pricing means that the highest accepted bid sets a market price that is paid to all accepted bids. Such a pricing mechanism has several benefits:

- 1) Bids are not that sensitive to uncertainties in the market.
- 2) It simplifies the bidding process for small businesses. For them, it is optimal to simply offer the marginal cost of capacity.
- 3) The market price is well defined.

A well-defined strike price is for example an advantage if there is forward trading in the capacity market. The main problem with marginal pricing when procuring capacity, is exercise of market power. For example, there could be an equilibrium where a dominant firm places a bid at the price cap, and other smaller firms place very low bids. Still, the small firms would sell their entire capacity at a price equal to the price cap. The dominant firm would have to lower its bid substantially to increase sales, which would be unprofitable. The risk that the market ends up in such a high-price equilibrium is particularly large in markets with a dominant firm and when the uncertainty in the market is small, so that it is possible to predict in advance which bid will set the price. The problem was described theoretically by von der Fehr and Harbord (1993) and has also been observed in NYISO's procurement of capacity (Schwenen, 2015). For some scenarios, Teirilä and Ritz (2019) get the high-price equilibrium in their simulations of the Irish capacity market, which has a dominant producer. Corresponding problems arose in Colombia's capacity market both in 2008 and 2011 (Harbord and Pagnozzi, 2014). Consequently, several of these markets have taken measures to reduce the problem. Colombia has tried to make it more difficult to predict in advance which bid will set the price by revealing less information between bidding rounds, although this did not help (Harbord and Pagnozzi, 2014). Harbord and Pagnozzi (2014) have suggested that the demand for capacity should be partly random.

**Conclusion** *Marginal pricing has many advantages, but can lead to extremely high prices, especially if there is a dominant agent in the market and uncertainty is low.*

Pay-as-bid means that any accepted bid is paid according to the own bid price. Under this setup all accepted bids set the price for each firm. As many bids are price setting, this reduces the risk of outcomes with very high prices (Fabra et al., 2006; Pycia and Woodward, 2019). A main problem with pay-as-bid is that each firm has an incentive to raise its bid until it is just accepted. Hence, bid prices will be very similar, regardless of whether the bidder has high or low costs. Thus, small errors can have major consequences for the outcome. For example, the allocation may be inefficient, such that an agent with a high cost of offering capacity wins the procurement, while an agent who can offer capacity at a lower cost (but bids too high) may not sell any capacity. Anderson et al. (2013) show that this problem is exacerbated by the fact that bidding can become volatile and unpredictable in a procurement that applies pay-as-bid. Furthermore, the agents are more dependent on accurately forecasting the outcome of the auction, so that they can maximize their profit. This increases the costs of participating in a capacity auction, which disadvantages small firms.

**Conclusion** *Pay-as-bid reduces the risk of high prices, but capacity procurement can be inefficient and disadvantage small firms.*

Power plants often are heterogeneous in terms of ramping rates or their location in the network. If there are significant differences between the plants, it will be inefficient to define a single market price that applies to all procured capacity. It would be theoretically possible to define a market price for each product category, but it may be easier for accepted bids to be paid-as-bid instead. Furthermore, the bidding behavior changes when the generation units are imperfect substitutes, which should reduce the problems of pay-as-bid pricing.

Combining marginal pricing and pay-as-bid probably leads to a more robust design. If, for example, 80 % of the payment is according to the marginal price and 20 % according to bid, then the worst possible outcomes, high prices or inefficient allocation, should be avoided. Another advantage is that it is easy to adjust the shares for the two pricing methods if problems should arise after all. The design has been studied theoretically by Ruddell et al. (2017) and Woodward (2019). New Zealand had for a while plans to introduce the combination in the spot market for electricity, but it has never been tested in practice.

Auctions with a Vickrey–Clarke–Groves (VCG) design are another option (Ausubel and Milgrom, 2006). In this setup, firms are paid the procurer’s opportunity cost. This is the additional amount the procurer would have to pay if the firm did not participate in the auction. Bidding the true marginal cost is a dominating strategy under this mechanism. In theory, there will be no mark-ups on the bids, not even from agents with market power. The allocation of capacity will then be efficient. However, transaction prices will still be above marginal cost, as for other auction designs. A challenge is that there will be different prices for different bidders. This problem also exists with pay-as-bid, but for VCG the price is systematically higher for producers with market power because these firms require higher compensation to make truthful offers. This can be perceived as unfair and in the long run can also encourage smaller producers to merge, which worsens competition in the market. Problems can also

arise if a firm prefers competitors to earn as little as possible from the auction and is able to roughly predict which bids will be accepted. The firm can then strategically choose its own non-accepted bids in such a way that the competitors are paid a low price for their capacity while the bidder itself loses nothing. This problem occurred in European spectrum auctions from 2010 to 2012 (Fanebust and von der Fehr, 2013). The consequence was that different firms had to pay very different prices for similar licenses.

**Conclusion** *VCG auctions can be very effective, but small firms are systematically paid less than firms.*

## **5.8 Who should procure capacity?**

System operators are independent in the US and the UK, and it is therefore unproblematic that they handle the procurement of capacity. This arrangement is often referred to as the central-buyer approach. Things are more complicated in the other European countries because the system operators also own the transmission network and therefore are affected by the prices in the spot market. In these countries, it may be better to let another party handle procurement of production capacity. This is especially true for a market-wide capacity market, where large volumes are procured which will affect spot prices and the system operator's rents.

In some US markets, CAISO and SPP, and in France, retailers purchase capacity on behalf of their customers. This decentralized capacity market is said to be of the *capacity obligation* type. In the EU, the approach is often referred to as de-central obligation. This arrangement could be suitable for countries where the system operator owns the grid. Another potential advantage with decentralization is that retailers might be better at making use of demand response, which reduces the need for capacity (Neuhoff et al., 2016). Yet, synergies of an integrated market may be lost under decentralization: the peak loads of different retailers generally do not coincide perfectly, meaning that the overall peak load is somewhat smaller than the sum of the peak loads of all retailers (Neuhoff et al., 2016). Consequently, the decentralized capacity market could also result in higher overall capacity.

## **5.9 What information should firms receive during/after procurement?**

Investment costs and future electricity prices are uncertain when capacity is procured. These uncertainties are largely common to investors, at least to those that consider investing in similar technologies. In the latter case, both investment costs and spot market revenues of investors can be expected to be strongly positively correlated. All investments of the same type will therefore have approximately the same profitability, although it is uncertain just how profitable they will be. Under these conditions, there are advantages to investors learning from each other. With better information about competitors' bidding, each bidder can make a better estimate of their own investment costs and better estimate the future revenue in the spot market. One way to reveal such information is through short delivery periods for capacity and frequent procurements, so that firms learn from the outcome of each procurement. Another way is that procurement is preceded by trading in financial instruments, where agents are given the opportunity to secure a future capacity price. The price of such a financial product is

based on the information gathered in the market, and it is thus informative for investors. A third way is to arrange a dynamic procurement with several bidding rounds. After each bidding round, information is disclosed to the agents. Usually only aggregate information is revealed. Agents do not receive detailed information about individual competitors' bids. To improve the exchange of information, Cramton and Stoft (2007) recommend that bid data from the previous round should be reported by production technology. Ideally, the increased information will lead to the bids responding better to the agents' net costs and to the most suitable capacity winning the auction. Under favorable conditions, competition is also improved by more information (Milgrom and Weber, 1982; Holmberg and Wolak, 2018).

Harbord and Pagnozzi (2014) are generally skeptical of dynamic auctions in the capacity market. They claim that firms investing in different technologies cannot learn much from each other. Based on interviews with bidders in Colombia's capacity market, they further argue that the bidders' lowest acceptable price was not affected by the information they received during the bidding process. Anyway, there are disadvantages associated with improving the information flow during an auction. When ISO-NE procures capacity, the auction can last for five days with eight bidding rounds per day. This means that the procurement process will be very time-consuming and costly, both for ISO-NE and for the market participants. It becomes particularly complicated for smaller agents to participate in such an auction. In addition, there is larger risk that firms coordinate their bids in a dynamic auction, which in that case leads to higher prices.

**Conclusion** *Frequent procurement of capacity, or procurement in a dynamic auction, makes bidders more informed and can provide more efficient outcomes. However, the procurement process becomes more costly, and the risk of tacit collusion increases.*

## **5.10 How long in advance should capacity be procured?**

Procuring capacity long in advance means that suppliers will have time to build new capacity or upgrade existing capacity, after the auction has ended and before capacity is to be delivered. This means that the supply of capacity is more flexible, and that competition is better (Chao and Wilson, 2004). Another advantage is that it is easier to coordinate the investments if they are procured well in advance. At PJM and ISO-NE, capacity is traded up to three years before delivery (Spees et al., 2013). Cramton (2006) argues that in the ideal case, the procurement should be made so far in advance that all technologies have the chance to build new capacity. In practice, however, it is difficult to procure technologies with different construction times in the same auction (Batlle et al., 2015). In South America, there are often three different auctions with one, three and up to 20 years delay until delivery of capacity, where the latter is targeted at new hydro power (Harbord and Pagnozzi, 2008; Batlle et al., 2015). PJM and ISO-NE have auctions where the procured capacity can be corrected every year (Spees et al., 2013). California, MISO and NYISO have instead made the assessment that it is sufficient that capacity is procured a few months or days before delivery (Spees et al., 2013). Harvey et al. (2013) believe that this has contributed to poor competition in NYISO's procurement of capacity. However, an advantage of purchasing capacity just before delivery is that it becomes easier to estimate the availability of plants.

A related issue is the length of the delivery period, i.e., for how long a plant should commit to be on line. In PJM, ISO-NE and MISO, the delivery period for capacity is one month and the procured capacity is the same for each month. In California, the delivery period is also one month, but the procured capacity changes every month. Delivery periods are much longer in South America. There, the delivery period is often several years and can be up to 30 years (Batlle, 2015). One guess is that the long delivery periods in South America, compared to the US, can be explained by the fact that the technology, e.g., hydro power, is different and that the political uncertainty is higher in South America.

## 6 The strategic reserve

EU countries, such as Belgium, Finland, Sweden and Germany, use a *strategic reserve* instead of market-wide capacity payments. The motives for strategic reserves are roughly the same as for capacity markets; to ensure security of supply while limiting price risk, or to provide robustness to temporary deviations from the long-term market equilibrium.

Holmberg and Ritz (2019) show how an efficient strategic reserve should be designed for a simplified electricity market. Like a capacity market, plants in the strategic reserve should receive a fixed support in proportion to the size of the plant. When procuring capacity, bids should be accepted from those who are willing to offer capacity at the lowest price per MW (irrespective of their marginal cost). For an efficient reserve, the efficient capacity payment is  $p^* = \pi_{LOLP}^*(p_{VOLL} - \bar{p})$ , just as for market-wide capacity payments. Hence, if the price cap  $\bar{p}$  has been set at  $p_{VOLL}$ , then there is no need for a strategic reserve in a simplified electricity market. For a simplified electricity market, it also does not matter whether the capacity price is predetermined to  $p^*$ , or if an amount  $\Delta q = q^* - q^0$  is procured to the reserve, where  $q^0$  is the market capacity that is active outside the reserve and  $q^*$  is the efficient market capacity.

The strategic reserve should only be used when other production is insufficient, and there is a threat of power shortages. In that situation, the spot price should be set at the price cap.<sup>10</sup> Thus, the price for plants outside the reserve is independent of the size of the power reserve. It does not matter for other plants if the reserve is able to meet the rest of the demand or if there is a shortage of electricity. In this way, the rest of the market is isolated from the strategic reserve. For plants outside the reserve, the electricity market essentially works as an energy-only market.

Holmberg and Ritz (2019) advocate that plants in the power reserve should be paid according to a market price for reserve power when they are used. That is, all production in the reserve is paid a price that is set by the running plant in the reserve that has the highest variable cost. Plants outside the reserve do not receive any capacity payment. On the other hand, they

---

<sup>10</sup> Neuhoff et al. (2016) argue that there should be a trigger price, below the price cap, where the strategic reserve should be activated. The motivation is that it is important to avoid price spikes to increase the social acceptance of the electricity market design. We think that it would be inefficient to have such a trigger price below the price cap. If social acceptance of the design is a major problem, it would be better to lower the price cap (when possible), instead of introducing a trigger price.

benefit from a high spot price, at the price cap whenever the power reserve is used. Holmberg and Ritz (2019) show that in market equilibrium of a simplified electricity market, the expected value of this extra income is equal to the capacity payment. This means that the power reserve is equivalent to a capacity market, at least for a simplified electricity market.

**Conclusion** *In a simplified electricity market, the strategic reserve is efficient if the following conditions are met: 1) Plants in the reserve receive the efficient capacity payment  $\pi_{LOLP}^*(p_{VOLL} - \bar{p})$ , 2) the reserve is used only when capacity in the rest of the market is exhausted, 3) the spot price is set to the price cap as soon as the power reserve is used, and 4) energy produced by the reserve is paid the marginal price of reserve power.*

Finally, it may be interesting to compare the strategic reserve with a capacity market in more detail. Consider a strategic reserve and capacity market with the same price cap and the same level of capacity payment per MW. For a simplified electricity market, the total capacity will be the same in both markets, and the technology mix will be the same. For the market with a strategic reserve, part of this capacity will be in the reserve. The total capacity payments are higher for a capacity market because all generation units receive a capacity payment. This is exactly offset by the fact that producers' total revenues in the spot market are higher in a market with a strategic reserve. The spot price is the same in both markets provided there is sufficient capacity outside the reserve or if there is a shortage of electricity. The difference in the spot price arises when the reserve has been activated without a power shortage. In that situation, the spot price for production outside the reserve is set at the price cap, while a market with market-wide capacity payments has a spot price that is equal to the marginal price of the plants in the reserve.

**Conclusion** *In a simplified electricity market with a strategic reserve, producers receive larger revenues from the spot market and smaller capacity revenues compared to a market-wide capacity mechanism that has the same price cap and capacity payment per MW. Producers' total revenues, and consumers' total costs, will be equal in both markets.*

## 6.1 Advantages of a strategic reserve versus a capacity market

Overall a strategic reserve has the same advantages and disadvantages as we mentioned for capacity markets in Section 5, but there are also some notable differences. A major difference between a strategic reserve and a capacity market is that capacity payments are only paid to a fraction of the plants. Only plants with the highest variable costs and lowest utilization rate would want to participate in the reserve, as the reserve is only used when the other capacity is insufficient. This capacity is often thermal peak power with high variable costs. Besides being efficient, another advantage is that it will be straightforward to define firm capacity for a large part of the units that will receive a capacity payment. Demand response is another technology that is often activated at high electricity prices. A potential problem with having demand response in a reserve is that it can be complicated, just as for market-wide capacity mechanisms, to define and verify a firm capacity for demand response.

Normally, renewable electricity production, hydro power and energy storage have a relatively low variable cost, or opportunity cost. Thus, it is rarely interesting for these technologies to

participate in the reserve. An advantage compared to capacity markets, is that there is no need to define a firm capacity for these technologies. They can operate outside the reserve under essentially the same conditions as in an energy-only market.

**Conclusion** *In an electricity market with a strategic reserve, it is relatively easy to define firm capacity for plants that will have a capacity payment, with a possible exception for demand response.*

A consequence of this result is that price signals will be more precise for plants inside and outside the strategic reserve, compared to a capacity market. Moreover, plants outside of the strategic reserve will have economic incentives to be available when capacity is most needed. A potential advantage of procuring a smaller volume is that even if the procurement is primarily targeted at plants with high variable costs, the large supply of other capacity should ensure viable competition in the procurement.

An additional potential advantage with the reserve is that it is isolated from the spot market if the market price is set at the price cap whenever there is a supply shortage in the spot market. The size of a strategic reserve will then have no effect on spot prices in the short or long run. Such minimal market impact is an advantage if transmission system operators (TSOs) are responsible for the procurement of the reserves. The fact that the reserve does not affect prices on the spot market also means that there will be fewer distortions to investments in intermittent generation or production facilities that feature ramping constraints.

**Conclusion** *A strategic reserve yields fewer distortions for intermittent generation, flexible production and energy storage compared to a capacity market that has price caps and capacity payments at the same level.*

Under a strategic reserve, market participants are still responsible for forecasting demand and choosing an appropriate investment portfolio. The reserve provides a margin, reduces the risk of electricity shortages, but in theory it should not affect other investments, at least not in the long run.

Distortions that occur because of special interests, short-termism or excessive risk aversion of political actors can occur in all types of capacity mechanisms. But this problem is likely to be smaller for strategic reserves than in market-wide capacity markets, as a larger volume is procured in the latter case (Neuhoff et al., 2016).

## **6.2 Disadvantages of a strategic reserve versus a capacity market**

A strategic reserve has some potential drawbacks compared to a capacity market. One is that there can be situations where it would have been efficient to use a plant in the reserve before a plant outside the reserve (Bublitz et al., 2019). This cannot occur under the simplified-market assumption in Holmberg and Ritz (2019), but it can happen under more realistic assumptions. For example, if the two plants have different locations and/or different flexibility, it may depend on the market conditions which plant it would be efficient to dispatch first.

For the same price cap, the reserve has a higher spot price (when the reserve is used). This means that, for the same price cap, the power reserve does not have the same mitigating effect on risks and market power. A higher risk means that investments are likely to shift towards low-capital investments with short lead times (Bublitz et al., 2019). If this is a problem for the strategic reserve, it can partly be mitigated by lowering the price cap on the spot market and increasing the capacity payment and procured volume of the reserve.

Many researchers advocate that authorities should set a level of reliability in the system and procure a capacity corresponding to that level. This will also reduce the problem with investment cycles (Bublitz et al., 2019). The authorities do not have the same control over the total capacity in an electricity market with a strategic reserve. The reserve mechanism is an intermediary between an energy-only market and a capacity market.

Ideally, investments outside the reserve will be the same regardless of the size of the strategic reserve. In practice, however, there is long-run uncertainty about the size of the reserve, which adds investment risk.

### **6.3 Strategic reserves in an integrated electricity market**

Analyses of capacity mechanisms usually are conducted under the assumption of a national electricity market. In an integrated multinational electricity market, the level of strategic reserves chosen in one country has effects abroad through the effects on prices and resource constraints. On the one hand, a larger domestic reserve has a positive effect abroad because it increases the overall reserve capacity. On the other hand, the domestic reserve can distort market prices and investments abroad. Tangerås (2018) shows that strategic reserves can be too large or too small in equilibrium depending on which effect dominates. This paper also demonstrates that the international externalities associated with strategic reserves will lead to underinvestment in network reliability even if network investments are coordinated across national borders. Underinvestment is exacerbated if the countries invest in network capacity based on national considerations.

If the EU sets a common price cap for all member states, then the price distortions of the strategic reserves disappear. This leaves only the positive effect associated with capacity reserves being available for uses abroad. By implication, strategic reserves in EU are likely to be too small. EU Regulation 2019:943 states that countries are only allowed to introduce a strategic reserve if can be justified based on a detailed analysis on the risk of power shortages. This supra-national approach to capacity reserves makes sense because of their cross-border effects. The welfare effect of strategic reserves is larger if their utilization is coordinated across borders, compared to the case where they are entirely used for national purposes. Neuhoff et al. (2016) argue that such coordination is both beneficial and feasible.

### **6.4 The strategic reserve in Sweden**

Electricity consumption increased and unprofitable production shut down after the deregulation of the electricity market in Sweden in 1996 (Swedish Government, 2009). The imbalance between consumption and supply was amplified by the government's decision to

close also the second reactor at the Barsebäck nuclear power plant. To cope with the shut-down of nuclear power without increasing the risk of power shortages, the Swedish TSO, Svenska Kraftnät (SvK), was instructed to procure a strategic reserve. At the outset this was a small preliminary reserve of 400-600 MW (SvK, 2013). The reserve became statutory in 2003, after which the size was increased to 2 000 MW. From the beginning, the idea was that the reserve should be a transitional solution until 2008, as the market was expected to catch up in the long run. However, the capacity reserve has been extended on three occasions, most recently until 2025. Between 2011 and 2017, the reserve was withdrawn to 750 MW. Due to the phase-out of additional nuclear-power plants in southern Sweden and domestic network congestion, SvK currently only procures capacity in southern Sweden. The reserve was activated on approximately ten occasions during the years 2009-13. On these occasions, up to 826 MW of the reserve was used (SvK, 2013).<sup>11</sup> Rolling blackouts have not occurred in Sweden since the deregulation of the market.

The government's long-run ambition is to phase out the reserve and leave capacity resolution to the market. According to the Swedish regulator, the Energy Markets Inspectorate (EMI, 2008), a market solution could be achieved with additional price zones and improved market integration. SvK (2013) estimates that the market reform in 2011 when the number of bidding zones in Sweden increased from one to four, increased trade with neighboring countries which indeed reduced the need for a strategic reserve. EMI (2008) also proposed to increase the share of demand response in the strategic reserve. In the short term, this would increase the procurement cost, but the change should have long-term benefits by stimulating demand flexibility (Swedish Government, 2009). According to Government Regulation 2010:2004 on strategic reserves, demand flexibility in the reserve was expected to increase from 25% to 100% during 2017/2018. However, it was impossible to achieve this objective, and in 2014 the regulation was amended so that at least 25% of the reserve would be demand response.

One issue with demand response is that it typically has limited endurance. It can be feasible to reduce electricity consumption for a few hours, but it will often be very costly to shut down industrial production for a prolonged period. An advantage of demand response is that activation is fast (SvK, 2013). For thermal production capacity in the reserve, it is usually the opposite, this capacity is enduring but needs to be notified well in advance (SvK, 2013).

All reserve capacity is required to be available 95% of the time, or else the capacity payment is reduced. For demand response, this means that a consumer must commit to using more than the sold capacity 95 % of the time. For energy-intensive industries, it has proven difficult to make such capacity commitment the required six months in advance. Hence, SvK has moved the procurement of demand response closer to the delivery period to facilitate participation by electricity-intensive industry.

The industry has also found it difficult to meet the availability requirements. These problems have led to changes in how demand response is managed in the reserve. Demand response

---

<sup>11</sup> In some cases, it would have been possible to use power outside the reserve (SvK, 2013). SvK estimates that a reserve of 400 MW would probably have been enough to avoid a power shortage during 2009-13.

active on the day-ahead market need not be available in the reserve. However, if the owners of this capacity declare that a reserve is unavailable for this reason, they will not receive any capacity payment for that delivery period. According to the new EU regulation for strategic reserves, capacity in the reserve is not allowed to participate in the spot market (EMI, 2020). Perhaps one could argue that capacity is outside the reserve when it does not receive any capacity payment. Still, there is a worry that the Swedish management of demand response might violate EU law, and SvK has suspended the procurement of demand response.

The procured capacity is reserved only for the winter period. There is only one bidding round, and the auction is executed approximately six months before the start of the winter period. Each generation unit in the reserve receives a fixed compensation equal to its own bid. Generation units that participate in the reserve procurement auction are heterogeneous, and the bids are therefore ranked according to a scoring rule. The scoring rule admits bids from all types of generation units, but it assigns a low score to units that fail to meet all technical performance and environmental specifications. The scoring rule also penalizes plants that ask for a high variable compensation. In addition, variable compensation is paid upon activation. For production capacity, this is done according to the bids (pay as bid). Energy from demand response is usually accepted via the real-time market and is paid a real-time price.

Under the current design, the spot price is set at the price cap as soon as there is excess demand in the day-ahead market. This means that the spot price is not affected by the size of the reserve, at least not in the short term. This procedure is in line with the design of the strategic reserve that Holmberg and Ritz (2019) advocate.

In 2016, the government decided that SvK should take environmental aspects into account in the procurement of the strategic reserve (Proposition 2015/16:117). The entire reserve must now consist of renewable generation capacity.<sup>12</sup> By implication, most units that previously participated in the reserve must be converted into biofuel plants. According to one study, this would increase variable costs by roughly 30%, and the total costs by 10-20% (Ceije, 2016). A concern has also been that the increased environmental requirements will reduce the supply of reserve capacity. These problems may possibly be a partial explanation for the recent lack of competition in the procurement auction. For example, a supplementary procurement had to be suspended during the winter of 2019/2020 when only one firm submitted a bid. We also note that in recent years, all capacity has been procured from one specific plant, *Karlshamnverket*, since the competing *Mälarenergi* and *Stenungsund* power plants have been closed.

## 6.5 Strategic reserves in other countries

Finland, Belgium and Germany introduced strategic reserves in 2011, 2014 and 2020.<sup>13</sup> The reserves in Belgium and Germany were partly motivated by a phase out of nuclear power. Similar to the Swedish reserve, they are only procured for the winter season, and are only

---

<sup>12</sup> SvK has the possibility to deviate from the environmental requirement if it drastically reduces the cost of procurement. However, the new EU regulation also contains environmental requirements. In the future, production in the power reserve may emit at most 550 g of CO<sub>2</sub> per kWh of electricity produced (EMI, 2020).

<sup>13</sup> In Germany, the procurement of capacity was in 2019, but delivery of capacity started in 2020.

activated if there is a shortage of electricity, i.e., when the spot price reaches the price cap. All the reserves have, or at least allow for, both thermal production and demand response. There are also differences relative to the Swedish design. In both Belgium and Germany, a plant cannot return to the market after it has been included in the reserve. One purpose is to isolate the reserve from the rest of the market. In addition, German plants can only stay in the reserve for a couple of years before they must close. This policy seems overly restrictive, at least from a resource adequacy perspective. The size of the reserve should be predictable, but this does not mean that the plants in the reserve should be fixed. We would argue that restrictions of this type would make it unattractive to enter the reserve. This could reduce market efficiency and worsen competition when capacity is procured.<sup>14</sup>

## **6.6 Can Sweden's strategic reserve be improved?**

In Section 5, we discussed how capacity markets should be designed. Many of the results also apply to strategic reserves. We share the opinion of Wolak (2019) that in an electricity market dominated by hydro power, it is not only capacity that needs to be procured but also energy. In that sense, it is an advantage that Sweden's strategic reserve mainly contains enduring thermal production capacity that can provide energy for a long period of time. On the other hand, this production usually requires a long notification time. Therefore, it is beneficial to have as a complement a smaller proportion of fast demand response. In the procurement auction, it would probably be better to specify performance criteria in terms of capacity, reaction time and reliability instead of specifying technologies in terms of generation and demand response. This generalization could increase the performance of the procurement auction. The change would also be in line with the new EU regulation, which stresses technology neutrality in the procurement of reserve capacity (EMI, 2020).

Competition is improved if demand for reserves is price sensitive. Instead of procuring a fixed amount of capacity, SvK could submit a demand curve, in line with many of US capacity markets. Perhaps it would be beneficial also to have more substitution elasticity between speed (demand response) and endurance (thermal power). The scoring rule applied by SvK already incorporates trade-offs of this nature, but across similar technologies with somewhat different specifications.

Marginal pricing has many advantages. It is normally the first choice of power exchanges and in other similar multi-unit auctions. Uniform capacity payments and marginal pricing are used in the design outlined by Holmberg and Ritz (2020) for a simplified electricity market, but it is likely that other designs such as pay-as-bid would also be efficient for a simplified electricity market. A weakness of marginal pricing is that only one bid sets the market price. Prices can then be very high if competition is poor, and it is possible to predict in advance which bid will set the price. Experience from capacity mechanisms outside Sweden suggests

---

<sup>14</sup> Germany has also introduced two other reserves. One is targeted to retiring coal plants, and the deals with redispatch. Bolton and Claussen (2019) write about the three reserves in Germany and the political process behind them. The reserve in Belgium is briefly discussed by Höschle and de Vos (2016).

that marginal pricing may be inappropriate. Alternative pricing methods could be more suitable for this procurement. Pay-as-bid, as applied by SvK, is one of them. A related problem is that plants have somewhat different properties and locations in the network. Hence, it is probably inefficient to use a single market price for all plants. This suggests that pay-as-bid pricing might be a good choice also for the variable compensation.

In a simplified electricity market, the level of variable compensation should not be considered when the reserve is procured. But this result applies to situations with perfect competition. Under imperfect competition it can probably be a good idea to give priority to bids with a low variable cost, which is the case today in Sweden. Exactly how variable bids should optimally be weighed is left for future research.

The supply of reserve capacity would probably increase if reserves were procured further in advance. It would then give the winners more time to modify their plants. In terms of demand response, the experience seems to be the other way around. The electricity-intensive industry seems to advocate that the time between procurement and delivery of capacity should be shortened. For demand response and other technologies where it is difficult to predict available capacity long in advance, it makes sense to make the procurement of capacity close to delivery when more information is available. Perhaps the most straightforward approach would be to stop procuring demand response to the strategic reserve and instead allocate this capacity to the ancillary services market. In particular, demand response is often fast, which makes it suitable for ancillary services. In Sweden, demand response within the strategic reserve is already activated in one of the ancillary-service markets (Reglerkraftmarknaden), so our tentative suggestion should not be a big step. Also, such a change should reduce the risk that the Swedish design violates EU law.

The strategic reserve is only procured for the winter months. Hence, procured plants compete on the energy-only market during the rest of the year, unless they close for the summer. A problem is that plants that have been in the reserve can distort prices in the energy-only market during the summer months. A tentative solution to this problem would be to require such plants to make bids at the price cap until the start of the next reserve.

All electricity production must bear the full costs of emissions and environmental damage. This objective becomes more difficult to satisfy when environmental requirements are stricter for production within the reserve compared to production outside. From an environmental perspective it would make more sense to have stricter rules for plants used on a regular basis (Neuhoff et al., 2016). In addition, the increased environmental requirements for the strategic reserve seem to have worsened competition since many facilities fail to meet those requirements. Reserves are used so infrequently that the environment would hardly be affected if the government dropped the requirement that 100% of the reserve must be renewable. Relaxing the regulation would increase the supply of capacity and make the procurement more competitive.

As mentioned, the strategic reserve has been used as an instrument to facilitate Sweden's nuclear decommissioning. This seems to be the main reason why Sweden introduced a power reserve and why it will be maintained at least until 2025. The strategic reserve has contributed

to the ability of the electricity system to absorb various unexpected political decisions. There are probably short-term benefits to this flexibility, but energy policy would perhaps have been more predictable if there was no reserve to fall back on. There has generally been a lot of experimenting with the reserve regarding its size and duration, the proportion of demand response and the environmental requirements. This experimentation has led to increased political uncertainty and increased investment costs.

## 7 Conclusions

Energy-only is the most effective electricity market design in theory. In practice, many markets use complementary capacity mechanisms. One reason is that it takes a long time to build new capacity, so temporary capacity shortages can occur due to investment cycles, new regulations, and technology shifts. Investment cycles, simultaneous closure of ageing power plants, combined with stricter environmental regulation were part of the reason why UK decided to introduce a capacity market (Bolton and Clausen, 2019). The strategic reserves in Belgium, Germany and Sweden have been used to facilitate phase-out of nuclear power. Investments in renewable technologies, mainly driven by support policies, have reduced electricity prices. Portugal and Spain have introduced capacity mechanisms to prevent thermal production from being pushed out of the market. A problem with US market designs has been that price caps tend to be low, partly for political reasons. Capacity payments have been used to compensate for the resulting missing money problem. Low price caps reduce price volatility, which is useful in countries where financial markets are less developed, such as South America. Perhaps increased uncertainty related to future energy and climate policies and to rapid technology development will increase the demand for capacity mechanisms.

In this paper, we have focused on two types of capacity mechanisms, capacity markets that feature market-wide capacity payments, and strategic reserves for which capacity payments are targeted to a few selected plants. For an idealized benchmark market, well-designed strategic reserves and capacity markets would be equally efficient. In practice, we argue that a strategic reserve would often be a better choice than a capacity market. Capacity markets are mostly fine for thermal capacity, but it is hard to define firm capacities that give correct price signals for intermittent renewable production, demand response, hydro power and other energy storage. Such issues have caused practical problems in for example the US and in South America, when procured capacity was not available when needed. Another issue with capacity markets is the bureaucratic process of verifying and approving capacity, which is mainly a problem for small plants. Distortions can occur for any capacity mechanism, e.g. due to special interests, short-termism or excessive risk aversion of political actors. But this problem is likely to be smaller for strategic reserves than in market-wide capacity markets, as a larger volume is procured in the latter case.

In a strategic reserve, only plants high up in the merit order, normally thermal plants, would be interested in contributing to a strategic reserve. For such plants it is straightforward to define firm capacity. Moreover, the bureaucratic process of verifying and approving capacity

is reduced to a small number of generation units. If the price cap is set on a federal level in EU, then strategic reserves should not cause any price distortions in neighboring countries.

The paper has discussed the strategic reserve in Sweden in detail. This mechanism seems to be well designed overall. A remaining problem is how to manage demand response in the reserve. A tentative suggestion is to procure demand-response capacity to the ancillary services instead. Demand response is fast, but not enduring, so it should be more suitable for ancillary services. This would also mean that demand response would be procured closer to delivery and have shorter delivery periods. This should make it easier for consumers to predict how much and for how long they can reduce their consumption.

Imperfect competition is a major problem for many capacity mechanisms. In theory, this problem should be smaller for strategic reserves, which only procure a small fraction of the total capacity in the market. But many countries put additional constraints on plants in the reserve, which does not seem efficient from a resource adequacy perspective, and this worsens competition. In Sweden there has been problem with competition when procuring thermal capacity to the Swedish reserve. The problem seems to have become worse since the requirement that all capacity in the reserve must be 100% renewable. We suggest that this rule is relaxed, and that thermal capacity is procured longer in advance to increase the supply.

Capacity markets have advantages. Compared to strategic reserves they are better at mitigating risk and market power. In addition, volume-based capacity markets are better at stabilizing the capacity in the market and to counteract investment cycles. Hence, a volume-based capacity market should be a better design for an electricity market dominated by thermal production which suffers from significant investment cycles.

## References

ACER (2019). Market Monitoring Report 2018 -- Electricity Wholesale Markets Volume. Agency for the Cooperation of Energy Regulators, 11 November 2019.

Ahlqvist, V., P. Holmberg and T. Tangerås (2018). Central-versus self-dispatch in electricity markets. IFN Working Paper 1257.

Amundsen, E.S., and L. Bergman (2007). Provision of operating reserve capacity: Principles and practices on the Nordic Electricity Market. *Competition and Regulation in Network Industries*, 2(1), 73-98.

APPA – American Public Power Association (2017): RTO capacity markets and their impacts on consumers and public power, Issue Brief, July.

Anderson, E.J., P. Holmberg and A.B. Philpott (2013): Mixed strategies in discriminatory divisible-good auctions. *RAND Journal of Economics* 44(1), 1-32.

Arango, S., and E. Larsen, (2011). Cycles in deregulated electricity markets: Empirical evidence from two decades. *Energy policy* 39(5), 2457-2466.

- Armstrong, M., S. Cowan and J. Vickers (1994): *Regulatory Reform: Economic Analysis and British Experience*. MIT Press.
- Astier, Nicolas, and Xavier Lambin (2019). Ensuring capacity adequacy in liberalised electricity markets. *The Energy Journal* 40, no. 3.
- Ausubel, L. and P. Milgrom (2006): The lovely but lonely Vickrey auction. Chapter 1 in P. Cramton, Y. Shoham, and R. Steinberg (red.): *Combinatorial Auctions*. MIT Press.
- Battle, C., P. Mastropietro, P. Rodilla and I.J. Pérez-Arriaga (2015). The system adequacy problem: Lessons learned from the American continent. In: L. Hancher, A. de Houtelocque and M. Sadowska (red.). *Capacity Mechanisms in the EU Energy Market: Law, Policy, and Economics*. Oxford University Press.
- Bergman, L. and C. Le Coq (2019): Blowing in the wind. *Energiforsk* 2019:587.
- Biggar, D.R. and M.R. Hesamzadeh (2014): *The Economics of Electricity Markets*. IEEE Press.
- Bolton, R. and T. Clausen (2019): Ambiguous interventions: Capacity remuneration mechanisms and the politics of energy transition in Britain and Germany. *Energy Research & Social Science* 56, 101218.
- Bublitz, A., D. Keles, F. Zimmermann, C. Fraunholz and W. Fichtner (2019): A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms. *Energy Economics* 80, 1059-1078.
- CAISO (2020): Preliminary Root Cause Analysis – Mid-August 2020 Heat Storm. October 6, 2020.
- Ceije, J. (2016): En konsekvensanalys till förordning om effektreserv. Unpublished manuscript, Ministry of Environment and Energy.
- Chao, H.-P. (1983). Peak load pricing and capacity planning with demand and supply uncertainty. *Bell Journal of Economics* 14(1), 179--190.
- Chao, H.-P. and R. Wilson (2004). Resource adequacy and market power mitigation via option contracts. EPRI report, Palo Alto, CA.
- Cramton, P. (2006). New England's forward capacity auction. Unpublished manuscript, University of Maryland.
- Cramton, P. and S. Stoft (2007). Colombia's firm energy market. Unpublished manuscript.
- Cramton, P. and S. Stoft (2008): Forward reliability markets: Less risk, less market power, more efficiency. *Utilities Policy* 16(3), 194-201.
- Cramton, P., A. Ockenfels and S. Stoft (2013): Capacity market fundamentals. *Economics of Energy & Environmental Policy* 2(2), 27-46.

- Crew, M. and P. Kleindorfer (1976). Peak load pricing with a diverse technology. *Bell Journal of Economics* 7(1): 207--231.
- EMI (2008). Effektfrågan – Behövs en centralt upphandlad effektreserv? Rapport 2008:15.
- EMI (2020). Ren energi inom EU – Ett genomförande av fem rättsakter. Rapport R2020:02.
- ENTSO-E (2015). Statistical Factsheet 2015. [www.entsoe.eu/publications/statistics-and-data/#statistical-factsheet](http://www.entsoe.eu/publications/statistics-and-data/#statistical-factsheet)
- Fabra, N. (2018). A primer on capacity mechanisms. *Energy Economics* 75, 323-335.
- Fabra, N., N.H. von der Fehr and D. Harbord (2006). Designing electricity auctions. *RAND Journal of Economics* 37(1), 23-46.
- Fanebust, E. and N-H. von der Fehr (2013). The combinatorial clock auction: A critique. Unpublished manuscript, University of Oslo.
- Fehr, N. H. and D. Harbord (1993). Spot market competition in the UK electricity industry. *Economic Journal* 103(418), pp. 531-546.
- Harbord, D. and M. Pagnozzi (2008). Review of Colombian auctions for firm energy. Report commissioned by the Colombian Comisión de Regulación de Energía y Gas.
- Harbord, D. and M. Pagnozzi (2014). Britain's electricity capacity auctions: lessons from Colombia and New England. *The Electricity Journal* 27(5), 54-62.
- Harvey, S.M., W.W. Hogan and S.L. Pope (2013). Evaluation of the New York Capacity Market. *Cambridge, MA*.
- Hobbs, B.F. (2005). Affidavit of Benjamin F. Hobbs on Behalf of PJM Interconnection, LLC. Filed before the Federal Energy Regulatory Commission. August 5, 2005.
- Hobbs, B.F., M.-C. Hu, J.G. Iñón, S.E. Stoft and M.P. Bhavaraju (2007). A dynamic analysis of a demand curve-based capacity market proposal: The PJM reliability pricing model. *IEEE Transactions on Power Systems* 22(1), 3-14.
- Höschle, H. and K. de Vos (2016): Implementation of a strategic reserve in Belgium: Product design and market results. Report C5-216, Cigré Meeting.
- Holmberg, P. and D. Newbery (2010). The supply function equilibrium and its policy implications for wholesale electricity auctions. *Utilities Policy* 18(4), 209-226.
- Holmberg, P. and R. Ritz (2019): Capacity mechanisms and the technology mix in competitive electricity markets. IFN Working Paper 1292.
- Holmberg, P. and F.A. Wolak (2018): Comparing auction designs where suppliers have uncertain costs and uncertain pivotal status. *RAND Journal of Economics* 49(4), 995-1027.

- Rose, J., S. Muthiah, F. Brock, J. Karp, and T. Sakya (2014): Addendum to polar vortex energy pricing implications— Commercial opportunities and system reliability, White Paper, ICF International, Inc.
- Joskow, P. and J. Tirole (2007): Reliability and competitive electricity markets. *RAND Journal of Economics* 38(1), 60-84.
- Lambin, X. (2020). The integration of demand response in capacity mechanisms, *Utilities Policy*. Forthcoming.
- Llobet, G. and J. Padilla (2018). Conventional power plants in liberalized electricity markets with renewable entry. *The Energy Journal*, 39(3), 69-91
- Léautier, T.O. (2019). *Imperfect Markets and Imperfect Regulation: An Introduction to the Microeconomics and Political Economy of Power Markets*. MIT Press.
- Mauritzen, J. (2014). Scrapping a wind turbine: Policy changes, scrapping incentives and why wind turbines in good locations get scrapped first. *The Energy Journal* 35(2), 157-181.
- McRae, S.D. and F.A. Wolak, (2019). Market power and incentive-based capacity payment mechanisms. Unpublished manuscript, Stanford University.
- Milgrom, P. R. and R. J. Weber (1982). A theory of auctions and competitive bidding. *Econometrica*, 1089-1122.
- Nelder, C. (2013). The perils of electricity capacity markets, September 4, 2013, *Greentechmedia*.
- Neuhoff, K., J. Diekmann, F. Kunz, S. Rüster, W-P. Schill, and S. Schwenen (2016). A coordinated strategic reserve to safeguard the European energy transition. *Utilities Policy* 41, 252-263.
- Newbery, D. (1997). Pool reform and competition in electricity. Unpublished manuscript, University of Cambridge.
- Newbery, D. and Grubb, M. (2014). The Final Hurdle?: Security of supply, the Capacity Mechanism and the role of interconnectors. Cambridge Working Papers in Economics 1433, Faculty of Economics, University of Cambridge.
- Newbery, D. (2020). Club goods and a tragedy of the commons: The Clean Energy Package and wind curtailment. Cambridge Working Papers in Economics, Faculty of Economics, University of Cambridge.
- Newell, S.A., K. Spees, J.P. Pfeifenberger, R.S. Mudge, M. DeLucia, and R. Carlton (2012). ERCOT investment incentives and resource adequacy. Consultancy report by The Brattle Group.
- Öko-Institut, LBD, Raue (2012). Ein neues Marktdesign für den Übergang zu einem neuen Energiesystem. Studie für die Umweltstiftung WWF. Berlin, 8 October 2012.

- Pycia, M., and K. Woodward (2019). Auctions of homogeneous goods: A case for pay-as-bid. Working paper.
- Roques, F. and C. Verhaeghe (2015): Different Approaches for Capacity Mechanisms in Europe: Rationale and Potential for Coordination? I L. Hancher, A. de Houteclocque and M. Sadowska (ed.). *Capacity Mechanisms in the EU Energy Market: Law, Policy, and Economics*. Oxford University Press.
- Ruddell, K., A.B. Philpott and A. Downward (2017). Supply function equilibrium with taxed benefits. *Operations Research*, 65(1), 1-18.
- Schwenen, S. (2015). Strategic bidding in multi-unit auctions with capacity constrained bidders: the New York capacity market. *RAND Journal of Economics*, 730-750.
- Spees, K., S.A. Newell, and J.P. Pfeifenberger (2013). Capacity markets—Lessons learned from the first decade. *Economics of Energy & Environmental Policy* 2(2), 1-26.
- Stoft, S. (2002): *Power System Economics: Designing Markets for Electricity*. IEEE Press.
- Stoft, S.E. (2004): Prepared direct testimony on behalf of ISO New England. Submitted before the FERC.
- Stoft, S.E. (2005): Prepared rebuttal testimony on behalf of ISO New England. Submitted before the FERC.
- Svenska Kraftnät (2013). Effektreserven - En uppföljning och analys av avvecklingen av den svenska effektreserven. Report in Swedish.
- Swedish Government (2009). Effektreserven i framtiden. Proposition 2009/10:113.
- Swedish Government (2015). Effektreserv 2020–2025. Proposition 2015/16:117.
- Tangerås, T. (2018): Equilibrium supply security in a multinational electricity market with renewable generation. *Energy Economics* 72, 416-435.
- Teirilä, J. and R.A. Ritz (2019). Strategic behaviour in a capacity market? The New Irish Electricity Market Design. *The Energy Journal*, forthcoming.
- Willems, B., (2015). The generation mix, price caps and capacity payments. EU energy capacity mechanisms In: L. Hancher, A. de Houteclocque and M. Sadowska (ed.). *Capacity Mechanisms in the EU Energy Market: Law, Policy, and Economics*. Oxford University Press, 140-156.
- Wolak, F.A. (2004). What's wrong with capacity markets? Unpublished manuscript, Stanford University.
- Wolak, F.A. (2019). Wholesale electricity market design. Unpublished manuscript, Stanford University.

Wolak, F.A. (2021). Market Design in an intermittent renewable future – Cost recovery with zero-marginal-cost resources, *IEEE Power & Energy Magazine*, January/February.

Woodward, K. (2019). Hybrid mechanisms for the sale of divisible goods. Mimeo. University of North Carolina at Chapel Hill.

Zöttl, G. (2010). A framework of peak load pricing with strategic firms. *Operations Research* 58(6), 1637-1649.