Utilities Policy xxx (2017) 1–14

Contents lists available at ScienceDirect

Utilities Policy

journal homepage: www.elsevier.com/locate/jup

# Capacity Remuneration Mechanisms in the Integrated European Electricity Market: Effects on Welfare and Distribution through 2023

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A R T I C L E I N F O

*Article history:*
Received 21 November 2014
Received in revised form
29 April 2016
Accepted 20 October 2016
Available online xxx

*JEL classification:*
C63
D47
D61

*Keywords:*
Electricity market
Capacity mechanism
Investment model

A B S T R A C T

A reduced attractiveness of investments in reliable fossil power plants in liberalized markets on the background of a transition towards renewable energies has brought a discussion on capacity policies to Europe. I develop a partial equilibrium model to compare effects of three polar capacity remuneration mechanisms (CRMs) based on the assumption that a CRM is indicated. A strategic reserve (SR) policy with administratively set capacity targets, a capacity market (CM) based on public procurement, and a decentralized reserve market with the obligation of generators to finance reserves in relation to their peak supply (RM). Substantial differences of policies arise across countries and regarding consumers and producers due to power plant structures. By 2023, we find the decentralized RM to induce least pronounced distributional effects and only modest welfare reductions, while SR and CM induce higher losses. In the longer term until 2033, welfare results differ less pronounced, although the RM is most friendly to consumers. A robust policy conclusion has to pay attention to further aspects concerning the environment and technological developments.



## 1. Introduction

A stream of literature investigates efficient pricing in electricity systems, market failure and policy proposals for the achievement of reliable and adequate generation capacity. In order to provide a starting point for the introduction of policy oriented work, I first summarize basic insights from the literature on efficient pricing and give an overview of possible market failures.

Dating back to the era of electricity supply by regulated monopolies, one strand of economic research has been concerned with how to price and incentivize efficient capacity levels. The peak load pricing literature started in the field of electricity with the analysis of cases in a deterministic setting. Boiteux (1960) finds that while off peak consumers should pay only the marginal costs, marginal costs as well as capacity costs have to be borne by peak load consumers. Crew and Kleindorfer who introduce a multiplicity of technologies and uncertainty on the demand side further elaborated these insights. Their numerical results illustrate that as the diversity of technology increases, a higher level of security of supply becomes desirable. They state that the "analysis indicates that a practical evaluation of optimal safety margins is [...] involving a simultaneous assessment of pricing and capacity [...]" (Crew and Kleindorfer (1976)). Chao (1983) extended these findings by also including uncertainty on the supply side. He finds that plant outage probabilities, cost differentials between technologies as well as the length of peak load events are essential for optimal time differentiated pricing. The basic insight of this literature is that efficient prices include a mixture of marginal costs and fixed costs, where periods with more than average consumption, and corresponding high probabilities for a loss of load, contribute over proportionally to fixed costs. Moreover, the optimal mixture of price components depends on time profiles of the uncertainties regarding demand and the availability of technologies.

Real world liberalized electricity markets hardly implement the theoretical ideal of peak load pricing. On one hand, occasional high electricity price peaks are frequently limited by explicit price caps, out of market actions (redispatch) or the inadequate remuneration of ancillary services (Hogan (2013), Newbery (2016)), thereby creating a problem of missing money for investors. On the other hand, it is argued that power plant projects are time consuming so that scarcity prices that correctly signal the demand for capacity may prevail until the new capacities are built, leading to potentially large transfers from consumers to producers (Oren (2003), de Vries and Hakvoort (2004)). Moreover, potentially adequate revenues may not be perceived to be so by generators or their financiers if

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http://dx.doi.org/10.1016/j.jup.2016.10.005

risks are not efficiently manageable, which indicates a problem of missing markets Newbery (2016).

Similarly, de Vries and Hakvoort (2004) summarize a variety of reasons in addi-tion to price caps, which may cause the market to fail to induce efficient investment levels. In particular, they point to the potential problem of imperfect information of investors in regard to stochastic demand and supply developments, as also described by Hobbs et al. (2002). In addition, a potential problem may arise due to regulatory uncertainty for instance with respect to emission policy, nuclear energy policy, and renewable energy policy as has recently been pointed at by Newbery (2016). Such uncertainties have especially pronounced consequences when investors choose a risk averse strategy, which is explained in more detail in Vazquez et al. (2002). These arguments are frequently dubbed market failures and give rise to the literature that provide quantitative and theoretical analysis of alternatives for capacity remuneration mechanisms (CRMs), although the case for the necessity of a CRM remains unclear.

Several of the aforementioned papers also compare effects of the introduction of possible policies for the remedy of assumed market failures. These studies predominantly use stochastic programming techniques under the assumption of inelastic demand (de Vries and Heijnen (2008), Hobbs et al. (2002), Vazquez et al. (2002)). For instance, based on a numerical electricity market model with growth, de Vries and Hakvoort (2004) emphasize the advantages of a system of capacity obligations due to its effective reduction of risk and lower price volatility compared to a policy of operating reserves, a pure energy only market or an energy only market with mar-ket power. More recently, Meyer and Gore (2015) added a numerical analysis to the discussion and demonstrated the importance of interconnections between electricity markets for the effectiveness of the policy design. They find that the unilateral introduction of CRM policies has negative cross-border effects aggravating the miss-ing money problem in an adjacent market without CRM. However, Meyer and Gore (2015) point out that the results critically depend on the assumptions concerning competition in the markets.

A most comprehensive study on policy proposals for electricity system reliability and adequacy is presented in Joskow and Tirole (2007) who cover many of the afore-mentioned aspects and assume the presence of price caps and demand rationing in an analytical framework. Elaborating on a variety of challenges for market solutions in the electricity system, Joskow and Tirole (2007) develop simple economic rules for second best solutions. They show how price caps reduce reliability and how reliability standards can be introduced to compensate for these deficiencies. However, Joskow stresses the view that price caps are unlikely to be the sole source of the so-called missing money problem (Joskow (2006), (2008)), and proposes a set of measures that can be used to remedy at least part of the suspected problems of liberalized markets. These measures include raising the price caps, require prices to rise to the price caps if the system operator has to take out of market actions (e.g. redispatch), increase real-time demand response, include more operating re-serves products in the market, and review and adjust reliability rules and protocols. Similarly, Lehmann et al. (2015) advocate on the basis of theoretical reasoning and empirical evidence that it is indicated to first strengthen existing structures before resorting to a complete reorganization of markets, particularly since it is difficult to revise such policy.

In summary, the results from the literature are ambiguous, and stress that the case for the introduction of CRMs and merits of their exact form depends on a variety of system characteristics. In addition, potential distributional effects of CRMs appear considerable as is emphasized by Oren (2003), and de Vries and Hakvoort (2004) and are to the best knowledge of the author not sufficiently studied earlier. I therefore investigate three polar CRMs to develop their distributional properties and relative welfare effects. However, I do not attempt to solve the question whether a CRM is indicated or not. Rather, the present work contributes to the understanding of the political economy of CRMs by highlighting their potentially substantial transfers. For that aim, I further develop a model on the basis of EMELIE-ESY (Schröder et al. (2013)).[1]

The set of analyzed policies include a strategic reserve (SR), a centralized capacity market (CM), and a reserve obligation implemented by a certificate scheme (RM). As the simplest form of capacity mechanism, a CM arises from an administratively set binding capacity target and rewards all firm capacity needed to reach the target with a payment. Instead of targeting firm capacity, we also consider mechanisms that more directly incentivize reserve capacity exemplified by the RM and SR policies. Under both regulations, a part of the power plant park operates only under predefined extreme conditions. In case of a SR, a regulator acquires as much capacities not sustained by the energy market, as the fulfillment of a target requires. By contrast, the RM leaves the exact amount of reserves to the market, but prescribes a capacity margin, which obliges suppliers to hold reserve capacities in excess of their expected supply peak. Similar to the operating reserve model proposed by Hogan (2013), the RM establishes a market for reserve capacities, and induces scarcity prices.

## 2. Model

In the following, the models for the simulation of a capacity market (CM), a strategic reserve policy (SR), and a reserve obligation with certificates (RM) are introduced. The representation of these policies is based on a model of an energy only market, which is described in the next subsection.

### 2.1. Basic energy only market model

We first model a basic energy only market with power generation and plant investment of firms acting on a domestic market. The time horizon consists of single periods $y$, each consisting of a number of time steps $t$. Marginal costs are constant in output $q$ in each period and include payments for emission allowances. They write:

$$C_q^{y,n} = \frac{p^{y,n} + \varphi^y e^n}{\eta^n} + oc^n, \tag{1}$$

where $\varphi^y$ denotes the periodic emissions price, and $p^{y,n}$, $e^n$, $\eta^n$ and $oc^n$ denote the periodic fuel price, the specific fuel emission, the degree of efficiency, and the unit operation and maintenance costs of technology $n$ respectively. Fixed costs accrue proportional to investments $k$ with $F^n$ denoting unit fixed costs.

Firms are assumed to behave competitively and to have perfect foresight. In particular, firms perfectly assign frequencies $f(\omega)$ to residual demand events denoted $\omega$. Inverse demand is denoted $P^{y,t,\omega}(X^{y,t,\omega})$, where $X$ denotes total consumption.

Now the profit maximization problem with regard to production $q$, and investment $k$ of a representative firm $i$ can be written as

[1] An advantage of the applied MCP format is the flexibility to represent a large range of economic problems including decisions under market power. Moreover, its mathematical description offers basic insights and intuition of the economic trade-offs related to the solution of the problems.

Please cite this article in press as: Traber, T., Capacity Remuneration Mechanisms in the Integrated European Electricity Market: Effects on Welfare and Distribution through 2023, Utilities Policy (2017), http://dx.doi.org/10.1016/j.jup.2016.10.005

$$\max_{q,k} \pi^i = \sum_{y=1}^{Y} \left(\frac{1}{1+\delta}\right)^y \sum_{n=1}^{N} \sum_{t=1}^{T} \sum_{\omega=1}^{\Omega} \Big(f(\omega)\Big(P^{y,t,\omega}\big(X^{y,t,\omega}\big) - C_q^{y,n}\Big)q^{i,y,n,t,\omega} - F^n k^{i,y,n}\Big). \quad (2)$$

The formulation shown in (2) simply says that profits are the sum of frequency weighted discounted differences between revenues and variable costs minus the discounted sum of investment costs.

The choice of the decision variables is bound by the following two restrictions. The first restriction ensures that production does not exceed the maximum of available installed net generation capacity, i.e. the sum of remaining base year capacity, $k_0^{i,y,n}$, and newly installed capacity commissioned until the period under consideration $\sum_{z=1}^{y} k^{i,z,n}$, multiplied by availability $a^n$, and writes:

$$\left(k_0^{i,y,n} + \sum_{z=1}^{y} k^{i,z,n}\right) a^n \geq q^{i,y,n,t,\omega}, \ \forall y \in Y, n \in N, t \in T, \omega \in \Omega. \quad (3)$$

A second restriction ensures that new installation does not exceed geographic or political restrictions for the expansion of certain technologies,[2] $\bar{k}^{i,y,n}$, and is given by:

$$\bar{k}^{i,y,n} \geq k^{i,y,n}, \ \forall y \in Y, n \in N. \quad (4)$$

The restricted optimization problem of firm $i$ can be reformulated as follows:

$$\max_{q,k} L^i = \sum_{y=1}^{Y} \left(\frac{1}{1+\delta}\right)^y \sum_{n=1}^{N} \sum_{t=1}^{T} \sum_{\omega=1}^{\Omega} \Bigg(f(\omega)\Bigg(\Bigg(\Big(P^{y,t,\omega}\big(X^{y,t,\omega}\big) - C_q^{y,n}\Big)q^{i,y,n,t,\omega} + \kappa^{i,y,n,t,\omega}\Bigg(\left(k_0^{i,y,n} + \sum_{z=1}^{y} k^{i,z,n}\right)a^n - q^{i,y,n,t,\omega}\Bigg)\Bigg) + \iota^{i,y,n}\left(\bar{k}^{i,y,n} - k^{i,y,n}\right) - F^n k^{i,y,n}\Bigg), \quad (5)$$

with shadow variables $\kappa^{i,y,n,t,\omega}$ and $\iota^{i,y,n}$ accounting for the restrictions in available capacity and investment feasibility respectively.

The first order conditions of firm $i$ with regard to supply write:

$$\frac{\partial L^i}{\partial q^{i,y,n,t,\omega}} = P^{y,t,\omega}\big(X^{y,t,\omega}\big) - C_q^{y,n} - \kappa^{i,y,n,t,\omega} \leq 0, \ \forall y \in Y, n \in N, t \in T, \omega \in \Omega, \quad (6)$$

and reflect perfectly competitive supply behavior under capacity restrictions, i.e. the shadow values of the capacity restriction $\kappa$ are equal to marginal profits.

The following first order conditions relate marginal profits to investment costs

$$\frac{\partial L^i}{\partial k^{i,y,n}} = \sum_{z=y}^{Y} \left(\frac{1}{1+\delta}\right)^z \sum_{t=1}^{T} \sum_{\omega}^{\Omega} \Big(f(\omega)\kappa^{i,z,t,n,\omega} a^n - \iota^{i,y,n}\Big) - F^n \leq 0, \ \forall y \in Y, n \in N. \quad (7)$$

Furthermore, the optimization variables are restricted to be non-negative, and if they are greater than zero, conditions (6) and (7) hold with equality:

$$q \geq 0, k \geq 0, q\frac{\partial L}{\partial q} = 0, k\frac{\partial L}{\partial k} = 0. \quad (8)$$

Similar conditions also apply to the shadow variables and corresponding restrictions:

$$\kappa \geq 0, \iota \geq 0, \frac{\partial L}{\partial \kappa} \geq 0, \kappa\frac{\partial L}{\partial \kappa} = 0, \frac{\partial L}{\partial \iota} \geq 0, \iota\frac{\partial L}{\partial \iota} = 0. \quad (9)$$

Finally, market clearing conditions ensure demand and supply balance, including trade flows and supply of renewable energy $q_{res}^{s,y,t,\omega}$.

For the representation of trade flows, the regional index $s$ is added. The market clearing conditions can now be written as:

$$X^{s,y,t,\omega}\big(P^{s,y,t,\omega}\big) = \sum_{i \in ii(s)} \sum_{n}^{N} q^{i,y,n,t,\omega} - \sum_{ss \neq s} \big(Ex^{s,ss,y,t,\omega} - Ex^{s,ss,y,t,\omega}\big) + q_{res}^{s,y,t,\omega}, \ \forall s \in S, y \in Y, t \in T, \omega \in \Omega, \quad (10)$$

where the LHS of (10) is the direct demand function, $ii(s)$ denotes the group of firms in region $s$, and $Ex^{s,ss,y,t,\omega}$ denotes an export from region $s$ to region $ss$. The market clearing conditions (10) remain unchanged throughout the model refinements presented in the following sections.

International trade is represented by an optimization problem of traders. More precisely, exports of electricity from region $s$ to region $ss$ are implied by the following profit maximization problem of a representative trader:

$$\max_{Ex} \pi = \sum_{y=1}^{Y} \sum_{t=1}^{T} \sum_{\omega=1}^{\Omega} \big(P^{ss,y,t,\omega}\big(X^{ss,y,t,\omega}\big) - P^{s,y,t,\omega}\big(X^{s,y,t,\omega}\big) - \tau^{s,ss,y,t,\omega}\big) f(\omega) Ex^{s,ss,y,t,\omega}, \ \forall ss \in S, \quad (11)$$

where $Ex^{s,ss,y,t,\omega}$ denotes electricity exports from country $s$ to the country of desti-nation $ss$, and $\tau^{s,ss,y,t,\omega}$ is the (scarcity) price of transmission capacity from region $s$ to $ss$, implied by the restricted maximum transmission line capacity $\overline{Ex}^{s,ss,y}$:

$$\overline{Ex}^{s,ss,y} \geq Ex^{s,ss,y,t,\omega}, \quad \forall ss \in S, y \in Y, t \in T, \omega \in \Omega. \quad (12)$$

Taking the derivative of (11) with respect to exports yields the first order optimality with respect to trade:

$$\frac{\partial \pi}{\partial Ex^{s,ss,y,t,\omega}} = P^{ss,y,t,\omega}\big(X^{ss,y,t,\omega}\big) - P^{s,y,t,\omega}\big(X^{s,y,t,\omega}\big) - \tau^{s,ss,y,t,\omega} \leq 0, \quad \forall s, ss \in S, y \in Y, t \in T, \omega \in \Omega. \quad (13)$$

Furthermore, optimality requires

$$\frac{\partial \pi}{\partial \tau} \geq 0, \tau \geq 0, \tau\frac{\partial \pi}{\partial \tau} = 0. \quad (14)$$

In conjunction with (14), (13) says that in case of exports the prices of the import country have to cover the prices of the export country plus the scarcity price of transmission capacity. The optimality conditions for trade, (13) and (14), do not change under the different regulations presented in the following.

### 2.2. Strategic reserve

In a system with strategic reserves the regional regulator fixes a minimum target for reliable capacity in a country, and provides

[2] For instance, the possible expansion of gas fired power plants in Poland could be limited by political objections against a further increase of the dependency on Russian gas.

sufficient payments for reserved capacities that are subsequently not allowed to participate in the energy market under normal conditions. Only under system stress, reserved units may be called into operation.[3] The strategic reserve policy potentially affects the energy market through three channels. First, it may withdraw existing capacities from the energy market under non-extreme situations, thereby raising electricity wholesale prices. Second, it may trigger additional new investment that is used in extreme situations, which dampens the wholesale prices in times of the extreme event. Thirdly, a fee to finance reserve payments is levied from consumers, which tends to reduce electricity demand.

The necessary reserve payments can be determined as the shadow values of appropriate restrictions that ensure the fulfillment of the capacity targets. Let the regulatory chosen target level of available capacity be equal to the peak demand, $\overline{Q}_{peak}^{s,y}$, multiplied by the reserve factor $\alpha$, and $\overline{q}_{res}^{s,y}$ denote exogenously supplied reliable capacity of renewable energy. Then the inequality restrictions induced by the capacity target can be written as

$$\sum_{i\in ii(s)}\sum_{n=1}^{N}\left(k_0^{i,y,n}+\sum_{z=1}^{y}k^{i,z,n}\right)a^n+\overline{q}_{res}^{s,y}\geq\overline{Q}_{peak}^{s,y}\alpha,\quad \forall s\in S, y\in Y, \tag{15}$$

where $ii(s)$ assigns a set of firms to each region. (15) establishes reserve payments $\sigma_{sr}^{s,y}$, which are sufficient to keep available capacities to be at least as high as peak demand multiplied by the reserve factor.[4]

Capacities $\overline{q}_{sr}^{i,y,n}$ that receive the reserve payment are only allowed to be used in the energy market in extreme demand event $\omega^*$. In the other demand events, the generation restriction of firm $i$ in period $y$ and technology $n$ of the basic model (3) becomes:

$$\left(k_0^{i,y,n}+\sum_{z=1}^{y}k^{i,z,n}\right)a^n-\overline{q}_{sr}^{i,y,n}-q^{i,y,n,t,\omega}\geq 0,\quad \forall y\in Y, n\in N, \omega\neq\omega^*. \tag{16}$$

The budget for reserve payments is financed by fee $\varsigma_{sr}^{s,y}$:

$$\varsigma_{sr}^{s,y}=\frac{\sum_{i\in ii(s)}\sum_{n=1}^{N}\overline{q}_{sr}^{i,y,n}\sigma_{sr}^{s,y}}{\sum_{t=1}^{T}\sum_{\omega=1}^{\Omega}f(\omega)X^{y,t,\omega}}. \tag{17}$$

The consumer price of electricity therefore becomes $P_{cons}^{s,y,t,\omega}=P^{s,y,t,\omega}+\varsigma_{sr}^{s,y}$, and corresponds with an adjusted inverse demand faced by suppliers.

Karush-Kuhn-Tucker formulation of the problem of firm $i$ requires an assignment of the regional values $\sigma_{sr}^{s,y}$ to the firms established by *loc(i)* and yields

$$\begin{aligned}\max_{q,\overline{q}_{sr},k}L^i=&\sum_{y=1}^{Y}\left(\frac{1}{1+\delta}\right)^y\sum_{n=1}^{N}\sum_{t=1}^{T}\sum_{\omega=1}^{\Omega}\Bigg(f(\omega)\Bigg(\Big(P^{y,t,\omega}(X^{y,t,\omega})\\&-C_q^{y,n}\Big)q^{i,y,n,t,\omega}+\kappa^{i,y,n,t,\omega}\Bigg(\left(k_0^{i,y,n}+\sum_{z=1}^{y}k^{i,z,n}\right)a^n\\&-q^{i,y,n,t,\omega}-\overline{q}_{sr}^{i,y,n}\Bigg)\Bigg)+\sigma_{sr}^{loc(i),y}\overline{q}_{sr}^{i,y,n}+\iota^{i,y,n}\Big(\overline{k}^{i,y,n}\\&-k^{i,y,n}\Big)-F^nk^{i,y,n}\Bigg).\end{aligned}$$

The KKT first order conditions of this problem with regard to supply of the representative firm writes

$$\frac{\partial L^i}{\partial q^{i,y,n,t,\omega}}=P^{y,t,\omega}(X^{y,t,\omega})-C_q^{y,n}-\kappa^{i,y,n,t,\omega}\leq 0,\ \forall y\in Y, n\in N, t\in T, \omega\in\Omega, \tag{18}$$

Investment decisions are guided by the first order condition with respect to in-vestments:

$$\frac{\partial L^i}{\partial q^{i,y,n}}=\sum_{z=y}^{Y}\left(\frac{1}{1+\delta}\right)^z\sum_{t=1}^{T}\sum_{\omega=1}^{\Omega}\left(f(\omega)\kappa^{i,z,t,n,\omega}a^n-\iota^{i,z,n}\right)-F^n\leq 0,\ \forall y\in Y, n\in N, \tag{19}$$

The decision of the firm to sell reliable capacity of technology $n$ as strategic reserve is derived by differentiation of (18) with respect to reserved capacity. This yields

$$\frac{\partial L^i}{\partial\overline{q}_{sr}^{i,y,n}}=-\sum_{t=1}^{T}\sum_{\omega=1}^{\Omega}f(\omega)\kappa^{i,y,n,t,\omega}+\sigma_{sr}^{loc(i),y}\leq 0,\ \forall y\in Y, n\in N, \tag{20}$$

The first order conditions with regard to supply and investment, (18) and (19), are formally identical to the corresponding inequalities in the basic model. However, optimality condition (20) is added and the capacity restriction accounts for reserved capacity not available for generation. Consequently, the reserve payments $\sigma_{sr}^{loc(i),y}$ have to cover foregone operating profit in the energy market, $\sum_{t=1}^{T}\sum_{\omega=1}^{\Omega}f(\omega)\kappa^{i,y,n,t,\omega}$, if a firm sells capacity to the reserve and (20) holds with equality.

The remaining optimality conditions of the basic model, particularly (8) and (9), persist. Additionally, optimality requires $\overline{q}_{sr}\geq 0$, and $\overline{q}_{sr}\frac{\partial L}{\partial\overline{q}_{sr}}=0$.

### 2.3. Capacity market

In a regulation with capacity markets, the regional regulator fixes a capacity target and endows all reliable capacity with a sufficient payment. These capacities are only to be held available, and are not subject to any control of performance. The capacity market considered here simply induces more capacity on the market and consequently reduces the electricity wholesale prices, while it establishes a second stream of income for reliable units. In addition, a fee to finance capacity payments is levied from consumers.

The necessary capacity payments can be derived as shadow values of restrictions that ensure the fulfillment of the capacity targets. Let the reliable capacities of renewable energy $\overline{q}_{res}^{s,y}$ be exogenously given, and the capacity target be the forecasted peak load $\overline{Q}_{peak}^{s,y}$ multiplied by the system reserve factor $\alpha$, the capacity

[3] Note that I do not implement a corresponding extreme event that triggers the reserves in the examples studied in the results section. The reason is that the modeled prices are not reaching critical levels above several hundred Euro per MWh. Tables a) of the appendix shows that model prices stay below Euro 200, which is well below realistic trigger prices as is discussed e.g. in (Neuhoff et al. (2016)).

[4] See inequality (20) and the paragraph thereafter for an intuition on the determination of the reserve payments in interplay with energy market revenues.

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market can be expressed as the following market clearing condition of fixed capacity demand and capacity supply from regional firms:

$$\sum_{i\in ii(s)}\sum_{n=1}^{N} q_{cm}^{i,y,n} + \overline{q}_{res}^{s,y} \geq \overline{Q}_{peak}^{s,y}\alpha, \quad \forall s\in S, y\in Y, \tag{21}$$

with $ii(s)$ denoting the set of firms that are located in region $s$. The capacity market clearing conditions (21) induce corresponding shadow variables $\sigma_{cm}^{s,y}$, which are equal to the necessary equilibrium capacity prices included in the optimization of the firms below.

Under this regulation the firms' capacity sales, $q_{cm}^{i,y,n}$, are restricted to its available capacities, leading to the following inequality restrictions:

$$\sum_{z=1}^{y}\left(k^{i,z,n} + k_0^{i,y,n}\right)a^n \geq q_{cm}^{i,y,n}, \quad \forall y\in Y, n\in N, \tag{22}$$

where the LHS of (22) is the sum of available remaining base year capacity and available new built capacity until period $y$. (22) induces shadow variable $\lambda^{i,y,n}$, which reflects the restriction to sell only available capacity on the capacity market.

The budget for capacity payments is financed through a fee, $\varsigma_{cm}^{s,y}$, charged on top of the electricity producer price:

$$\varsigma_{cm}^{s,y} = \frac{\left(\sum_{i\in ii(s)}\sum_{n=1}^{N} q_{cm}^{i,y,n} + \overline{q}_{res}^{s,y}\right)\sigma_{cm}^{s,y}}{\sum_{t=1}^{T}\sum_{\omega=1}^{\Omega} f(\omega)X^{y,t,\omega}}. \tag{23}$$

The consumer price of electricity is therefore $P_{cons}^{s,y,t,\omega} = P^{s,y,t,\omega} + \varsigma_{cm}^{s,y}$, which modifies the inverse demand in case of a capacity market.

The Karush-Kuhn-Tucker formulation of the problem of a regional firm can now be written as

$$\begin{aligned}\max_{q,q_{cm},k} L^i = {} & \sum_{y=1}^{Y}\left(\frac{1}{1+\delta}\right)^y \sum_{n=1}^{N}\sum_{t=1}^{T}\sum_{\omega=1}^{\Omega}\Bigg(f(\omega)\Bigg(\Big(P^{y,t,\omega}\left(X^{y,t,\omega}\right) \\ & - C_q^{y,n}\Big)q^{i,y,n,t,\omega} + \kappa^{i,y,n,t,\omega}\Bigg(\Bigg(k_0^{i,y,n} + \sum_{z=1}^{y} k^{i,z,n}\Bigg)a^n \\ & - q^{i,y,n,t,\omega}\Bigg)\Bigg) + \lambda^{i,y,n}\Bigg(\Bigg(k_0^{i,y,n} + \sum_{z=1}^{y} k^{i,z,n}\Bigg)a^n - q_{cm}^{i,y,n}\Bigg) \\ & + \sigma_{cm}^{loc(i),y} q_{cm}^{i,y,n} + \iota^{i,y,n}\left(\overline{k}^{i,y,n} - k^{i,y,n}\right) - F^n k^{i,y,n}\Bigg),\end{aligned}$$

where *loc(i)* assigns the regional capacity payments, $\sigma_{cm}^{s,y}$, into the domain of firms.

The KKT first order conditions of this problem with regard to supply of a price taking firm are:

$$\begin{aligned}\frac{\partial L^i}{\partial q^{i,y,n,t,\omega}} = {} & P^{y,t,\omega}\left(X^{y,t,\omega}\right) - C_q^{y,n} - \kappa^{i,y,n,t,\omega} \\ & \leq 0, \quad \forall y\in Y, n\in N, t\in T, \omega\in\Omega,\end{aligned} \tag{24}$$

and, thus, identical to the according conditions (6) of the basic model.

Investment decisions are guided by the following first order conditions:

$$\begin{aligned}\frac{\partial L^i}{\partial k^{i,y,n}} = {} & \sum_{z=y}^{Y}\left(\frac{1}{1+\delta}\right)^z \sum_{t=1}^{T}\sum_{\omega=1}^{\Omega}\left(f(\omega)\kappa^{i,z,t,n,\omega}a^n + \lambda^{i,z,n}a^n - \iota^{i,z,n}\right) \\ & - F^n \\ & \leq 0, \quad \forall y\in Y, n\in N.\end{aligned} \tag{25}$$

Capacity sales to the capacity market are determined by

$$\frac{\partial L^i}{\partial q_{cm}^{i,y,n}} = \sigma_{cm}^{loc(i),y} - \lambda^{i,z,n} \leq 0, \ \forall y\in Y, \ n\in N. \tag{26}$$

Inequality (26) says that the shadow variable of the capacity sales restriction is at least as large as the capacity price.

Since no real costs are involved, the regulation induces a complete sale of available capacities on the capacity market, and creates additional revenues that incentivize not only new capacity, but also existing units including variable renewable energy units. In addition to the above conditions and the persisting conditions of the basic model, particularly (8) and (9), optimality requires furthermore:

$$q_{cm} \geq 0, \text{ and } q_{cm}\frac{\partial L}{\partial q_{cm}} = 0, \frac{\partial L}{\partial \lambda} \geq 0, \lambda \geq 0, \text{ and } \lambda\frac{\partial L}{\partial \lambda} = 0.$$

### 2.4. Reserve obligations with capacity certificates

In a regulation with reserve obligations the regulator prescribes suppliers to guarantee firm capacity that establishes a reserve factor in relation to their peak supply under not extreme demand events. Under regulatory defined extreme demand events these reserves are free to supply. If firms are allowed to fulfill their capacity obligation either through sufficient own capacity reserves or through the purchase of certified capacity and if firms have different opportunity costs to fulfill their reserve obligation, the regulation will induce a market for certified firm capacity.

Market clearing on the capacity certificate market of region $s$ can be expressed as the equalization of the sum of certificate sales, $z_s^{i,y,t,\omega}$, and certificate purchases, $z_p^{i,y,t,\omega}$ of regional conventional suppliers $ii(s)$ and the sum of certificate sales created by renewable energy, $z_{RES}^{i,y,t,\omega}$, and net exports, $z_x^{i,y,t,\omega}$. Denoting the extreme demand event with $\omega^*$, the balance on the capacity certificate market can be expressed as:

$$\begin{aligned}& \sum_{i\in ii(s)}\left(z_s^{i,y,t,\omega} - z_p^{i,y,t,\omega}\right) + z_{res}^{s,y,t,\omega} + z_x^{s,y,t,\omega} \\ & = 0, \forall s\in S, y\in Y, t\in T, \omega\in\Omega, \omega\neq\omega^*,\end{aligned} \tag{27}$$

which determines regional certificate prices $\sigma_{rm}^{s,y,t,\omega}$ in normal demand events. Certificate sales of renewable energy are exogenously given, while certificate sales from exports are determined by the international price differences and certificate sales and purchases of conventional firms are implicitly given by the additionally restricted optimization described in the following.

The regulation requires the firms to hold reliable capacity or certificates of reliable capacity that cover their own peak supply in not extreme demand events at least with the reserve factor $\alpha$. Representative firm $i$'s decisions are thus restricted by

$$z_s^{s,y,t,\omega} - z_p^{i,y,t,\omega} \leq \sum_n \left( k_0^{i,y,n} + \sum_{z=1}^{y} k^{i,z,n} \right) a^n - \alpha \sum_n q^{i,y,n,t,\omega}, \forall y \in Y, t \in T, \omega \in \Omega, \omega \neq \omega^*, \tag{28}$$

which guarantees that net certificate sales are not greater than reliable capacity in excess of the requirement. (28) induces firm specific shadow prices $\mu^{i,y,t,\omega}$ in not extreme demand events.

Net imports to country $s$, $\sum_{s \in S} (Ex^{s,ss,y,t,\omega} - Ex^{ss,s,y,t,\omega})$, and inelastic supply from renewable energy sources (RES) denoted $q_{res}^{s,y,t}$ create additional certificates $z_X^s$ and $z_{RES}^s$. However, these supplies take the price for capacity as given. Consequently, their supply of certificates can be described by the following equalities. Certificate supply related to net export is

$$z_X^{s,y,t,\omega} \alpha \sum_{ss \in S} \left( Ex^{s,ss,y,t,\omega} - Ex^{ss,s,y,t,\omega} \right). \tag{29}$$

RES create certificate supply according to their inelastic output and their reliable capacity $\overline{q}_{res}^{s,y}$:

$$z_{res}^{s,y,t,\omega} = \overline{q}_{res}^{s,y} - \alpha q_{res}^{s,y,t,\omega}. \tag{30}$$

The problem of the conventional firm can now be stated as a problem of the Karush- Kuhn-Tucker type as follows:

$$\begin{aligned} \max_{q,z_s,z_p,k} L^i = & \sum_{y=1}^{Y} \left( \frac{1}{1+\delta} \right)^y \sum_{n=1}^{N} \left( \sum_{t=1}^{T} \right. \\ & \times \sum_{\omega=1}^{\Omega} f(\omega) \left( P^{y,t,\omega}(X^{y,t,\omega})(X^{y,y}) q^{i,y,n,t,\omega} - C_q^{y,n} q^{i,y,n,t,\omega} \right. \\ & + \kappa^{i,y,n,t,\omega} \left( \left( k_0^{i,y,n} + \sum_{z=1}^{y} k^{i,y,n} \right) a^n - q^{i,y,n,t,\omega} \right) \\ & + \sigma_{rm}^{loc(i),y,t,\omega} \left( z_s^{i,y,t,\omega} - z_p^{i,y,t,\omega} \right) + \mu^{i,y,t,\omega} \left( \left( k_0^{i,y,n} \right. \right. \\ & \left. \left. + \sum_{z=1}^{y} k^{i,y,n} \right) a^n + z_p^{i,y,t,\omega} - z_s^{i,y,t,\omega} - \alpha q^{i,y,n,t,\omega} \right) \Bigg) \\ & + \iota^{i,y,n} \left( \overline{k}^{i,y,n} - k^{i,y,n} \right) - F^n k^{i,y,n} \Bigg), \end{aligned} \tag{31}$$

where $loc(i)$ assigns the regional certificate prices, $\sigma_{rm}^{s,y,t,\omega}$, into the domain of firms.

Deriving the KKT conditions of this problem with regard to supply of firm $i$ we get:

$$\frac{\partial L^i}{\partial q^{i,y,n,t,\omega}} = P^{y,t,\omega}(X^{y,t,\omega}) - C_q^{y,n} - \kappa^{i,y,n,t,\omega} - \mu^{i,y,t,\omega} \alpha \leq 0, \forall y \in Y, n \in N, t \in T, \omega \in \Omega. \tag{32}$$

The conditions (32) show that the firm treats the additional requirement induced by an additional supply like an additional cost, i.e the firm deducts the shadow variable of its capacity requirement weighted with the reserve factor from marginal revenues.

The KKT first order conditions with regard to investment can be written as

$$\frac{\partial L^i}{\partial k^{i,y,n}} = \sum_{z=y}^{Y} \left( \frac{1}{1+\delta} \right)^z \sum_{t=1}^{T} \sum_{\omega=1}^{\Omega} \left( f(\omega) \left( \kappa^{i,z,t,n,\omega} + \mu^{i,z,t,\omega} \right) a^n - \iota^{i,z,n} \right) - F^n \leq 0, \quad \forall y \in Y, \ n \in N, \tag{33}$$

Certificate sales are guided by the following inequalities:

$$\frac{\partial L^i}{\partial z_s^{i,y,t,\omega}} = \sigma_{rm}^{loc(i),y,t,\omega} - \mu^{i,y,t,\omega} \leq 0, \quad \forall y \in Y, t \in T, \omega \in \Omega, \tag{34}$$

The certificate purchase decisions are ruled by an inequality that is equivalent to (34) up to a change in signs of the terms:

$$\frac{\partial L^i}{\partial z_p^{i,y,t,\omega}} = -\sigma_{rm}^{loc(i),y,t,\omega} + \mu^{i,y,t,\omega} \leq 0, \quad \forall y \in Y, t \in T, \omega \in \Omega, \tag{35}$$

Additionally, the following conditions have to hold: $z \geq 0$, and $z\frac{\partial L}{\partial z} = 0, \frac{\partial L}{\partial \mu} \geq 0$, $\mu \geq 0$, and $\mu \frac{\partial L}{\partial \mu} = 0$. In combination with these additional conditions, inequalities (34) and (35) show that when the firm trades in the capacity certificate market it sets the shadow price of its specific capacity requirement $\mu$ equal to the capacity price $\sigma$. Since the capacity price is only greater zero if the capacity requirement is binding, it follows that the firms supply decision described in (32) is impacted by the regulation only in peak load situations.

Finally, optimality conditions, particularly (8) and (9), of the basic model persist, while the optimal trade flows are based on prices net of certificate purchases. For all $s$ the prices $P^{s,y,t,\omega}$ in (13) are replaced by $P_{prod}^{s,y,t,\omega} = P^{s,y,t,\omega} - \sigma_{rm}^{s,y,t,\omega}\alpha$. Thus, I assume that exports are not burdened by the capacity certificate prices of the country of origin.

## 3. Scenarios and data

The model application assesses the interconnected electricity markets of Germany (De), France (Fr), and Poland (Pl), and computes reference years 2023 and 2033. For investment incentives, each represented year forms the basis of the calculation of ten consecutive years of electricity market revenues. Four load days with 24 hourly time steps represent in turn each reference year. Comparability of the three policies "Energy Only Market" (EOM), "Strategic Reserve" (SR), "Capacity Market" (CM), and "Reserve Obligation with Capacity Certificate Market" (RM) is achieved by the assumption of a common reserve margin of five percent excess firm capacity compared to the load peak.

Denoting reference demand with $D0^{s,t,\omega}$ and reference prices $P0^{s,t,\omega}$ , demand is represented by hourly linear demand functions of the form

$$D^{s,y,t,\omega}(P^{s,y,t,\omega}) = D0^{s,t,\omega} + D0^{s,t,\omega} \left( 1 - \frac{P^{s,y,t,\omega}}{P0^{s,t,\omega}} \right) |\varepsilon_0|,$$

where $\varepsilon_0$ is the assumed elasticity of demand at the reference point. In order to investigate the robustness of the model, I use a comparatively high elasticity scenario with elasticity of −0.4, and the lower elasticity with −0.2, which represents the reference assumption.

These values are in the range of findings from the literature, which is actually quite large and depends on the considered response time and consumption sector. Estimates for residential households and the long run vary from about −0.3 up to −1.3, while a recent study by Krishnamurthy and Kriström (2015) finds −0.5.

Please cite this article in press as: Traber, T., Capacity Remuneration Mechanisms in the Integrated European Electricity Market: Effects on Welfare and Distribution through 2023, Utilities Policy (2017), http://dx.doi.org/10.1016/j.jup.2016.10.005

Comparable results arise for price elasticities of industrial demand. They mostly range from −0.5 to −0.1.

Latest results are cited in the literature review as well as estimations of Bernstein and Madlener (2015). Other sectors have a smaller weight in total demand and do not contrast substantially from industry and households. For the purpose of this analysis, which takes the necessity of CRM for supply security as given, I assume the more critical case of a low elasticity as reference.

For the reference demand and price values, I adopt consumption data from ENTSO-E,[5] and wholesale prices for the year 2010. Total combined load of the three countries has been used to construct three seasons as a basis for three representing load days: a winter season with a 26.6 percent annual frequency, a shoulder season for autumn and spring with 25.8, and a low-load summer season with a 47.7 percent frequency. In combination with the availability of renewable energy these demand situations form the basis of the four load events represented in the model: winter (s1), shoulder (s2), summer (s3), and winter with low wind energy supply (s4). This latter event corresponds to a winter demand situation with only a sixth of the seasonal winter wind availability documented below with an assigned frequency of 0.3 percent. The reference spot market prices are constructed from the according time intervals based on POLPX[6] and EPEX[7] dayahead spotmarket data that show in average wholesale prices in 2010 of 44 Euro per MWh in Germany and France (both EPEX) and 46 in Poland (POLPX).

The demand data is furthermore scaled up by 5, 15 and 10 percent for Germany, France and Poland respectively and matches total annual reference demand of 562 TWh in Germany, 590 TWh in France, and 170 TWh in Poland in 2023[8]. For the representation of the development until 2033, I further assume a ten percent increase of reference demand. In this model application, renewable energy supplied by solar, wind and biomass units is exogenous, and generators face a residual demand net of these supplies. Solar, wind and biomass supply develops according to their installed capacities and their assumed supply profiles: While biomass supply is by assumption constant over time, wind and solar supply is based on time profiles of German wind and solar power production in the three demand seasons introduced previously. To get typical daily profiles, seasonal and hourly availability of wind power data from 2006 until 2012 has been averaged.[9] Photovoltaic power profiles are based only on data from the years 2011 and 2012, which is not problematic since it exhibits much less pronounced seasonal differences across years. The basic supply profiles imply averaged annual utilization rates of 27.0 percent for wind power, and 10.8 percent for solar power plants.

For Germany these profiles of wind and solar power are scaled to reach the annual utilization rates of 29.7 percent for wind power and 10.2 for solar power implied by the output and capacities for the year 2023 of scenario B of the German ÜNB (2013b). The profiles are laid out to exemplify the used hourly capacity factors in the three seasons s1 to s3 in Fig. 1. They show that wind power and solar power complement each other in the sense that their dominant supply seasons are inversely related. The windy winter season with an average availability of forty three percent corresponds to a poor solar power performance with an average availability of three percent. By contrast, in sunny summer solar has an average availability of sixteen percent and wind has only little more than half of its winter performance (23 percent).

The basic profiles are also used for the assumed hourly supply profiles of wind and solar in Poland and France, which are further scaled to match the capacity factors implied by the figures in the National Renewable Energy Action Plans (NREAPs) published in Beurskens and Hekkenberg (2011). These capacity factors are 26.4 percent for French, and 26.1 percent for Polish wind power respectively, which are achieved with scaling factors of 98 and 97 percent.

The generation of biomass power is based on an annual availability factor of 64 percent implied by ÜNB (2013b). The same availability is assumed for all coun-tries. The factors for Poland and France that are given implicitly by capacities and generation of the NREAP do not notably deviate. By contrast, average annual availabilities of hydro power show substantial differences across countries in line with the NREAPs for the year 2020, i.e. 53, 31 and 29 percent for German, French, and Polish generators respectively. Differing from the treatment of the other renewable energy sources, hydro power supply is calculated endogenously as a market decision and pumped hydro power supply is not considered.

Apart from energy, the renewable plants provide also significant reliable capacities, which is of special interest in the context of capacity mechanisms. We adopt reliability factors identical with average availabilities in case of biomass power plants. Concerning the fluctuating renewable energy sources wind and solar, reliability is strongly influenced by fluctuations under different meteorological conditions. This significantly reduces the reliability factor compared to average availability. For wind and solar I adopt 1 and 0 percent respectively in line with assumptions of the report of the German transmission system operators (ÜNB (2013a)). Renewable hydro power reliability is set in accordance with their country availabilities documented in the previous paragraph, whereas the provision of reliable capacity of pumped hydro storage is rated at 80 percent. The underlying hydro power capacities are based on Platts power plant database 2012 and data provided by ENTSO-E in the scenario outlook and adequacy forecast 2013–2030. As shown in Table 1, reliable capacities of renewable energies including pumped hydro storage in Germany amount to 13.8 GW by 2023 and 15.3 GW by 2033, where around 39 and more than 55 percent are provided by biomass and hydro capacities respectively. In France, hydro

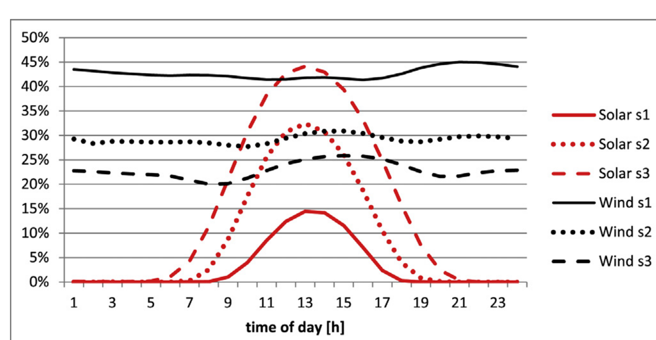


**Fig. 1.** Hourly seasonal wind and solar supply profiles in the seasons winter s1, shoulder s2 and summer s3 for Germany.

[5] This data is available at the ENTSO-E data portal, https://www.entsoe.eu/data/data-portal/consumption/. The German ENTSO-E values do not include industrial own consumption and parts of the consumption of railways, adding at average 8.5 percent.

[6] Polish Power Exchange.

[7] European Power Exchange.

[8] The German value corresponds to the value of the Network Development Plan 2013 ÜNB (2013b). This includes five percent assumed grid losses. French demand data is based on the Median scenario of the French Generation adequacy report RTE (2013), and the estimate for Poland assumes a ten percent increase in the current decade and is derived in accordance with the development of the Polish peak load as laid out in the demand prognosis ARE (2011) for the Polish ministry of economy.

[9] Seasonal wind power loses the major part of its variability when using average values. However, wind variability and its impacts are not the focus of this study and investment incentives are assumed to be impacted by variability only to a minor extent.

**Table 1**
Exogenous power plants by 2023 and 2033 in GW installed (top) and reliable (bottom) capacity.

| | Year | Country | Nuclear | Lignite | Hard Coal | Gas CC | Gas/Oil ST/GT | Renewables | Total |
|---|---|---|---|---|---|---|---|---|---|
| GW installed | 2023 | De | 0,0 | 16,9 | 26,3 | 14,3 | 11,3 | 144,4 | 213,0 |
| | | Fr | 61,2 | 0,0 | 3,3 | 5,3 | 4,3 | 66,5 | 140,6 |
| | | Pl | 0,0 | 6,7 | 18,1 | 1,3 | 0,4 | 13,9 | 40,4 |
| | 2033 | De | 0,0 | 11,4 | 20,0 | 13,6 | 4,6 | 178,2 | 227,7 |
| | | Fr | 17,6 | 0,0 | 2,7 | 5,3 | 3,8 | 92,8 | 122,3 |
| | | Pl | 0,0 | 6,0 | 8,4 | 1,3 | 0,2 | 21,6 | 37,6 |
| GW reliable | 2023 | De | 0,0 | 14,4 | 21,5 | 13,2 | 10,2 | 13,8 | 73,1 |
| | | Fr | 49,6 | 0,0 | 2,7 | 4,9 | 3,9 | 11,3 | 72,4 |
| | | Pl | 0,0 | 5,7 | 14,8 | 1,2 | 0,3 | 3,6 | 25,7 |
| | 2033 | De | 0,0 | 9,7 | 16,4 | 12,5 | 4,2 | 15,3 | 58,0 |
| | | Fr | 14,3 | 0,0 | 2,2 | 4,9 | 3,5 | 12,8 | 37,7 |
| | | Pl | 0,0 | 5,1 | 6,9 | 1,2 | 0,2 | 5,0 | 18,4 |

power plants deliver more than two-thirds of reliable renewable energy capacity. In Poland biomass is the dominant fully reliable renewable energy source.

The assessment of existing thermal generation capacities is based on information of Platts power plant database 2012 and minor own updates. These capacities are assumed to be decommissioned after a lifetime of 40 years in case of gas turbines (Gas GT, Oil GT), and 50 years in case of steam turbines (Lignite, Hard Coal, Gas, Oil) or combined cycle gas turbines (Gas CC). Furthermore, nuclear power plants in Germany are phased out completely, while a lifetime of 45 years for French nuclear power plants is adopted in correspondence with a governmental announcement to reduce the share of nuclear power to fifty percent by 2025. Table 1 shows reliable thermal capacities.

In Germany, remaining reliable capacity sums up to 73.1 GW by the year 2023 and 58.0 GW by the year 2033 implying a reduction of 21 percent in that decade. The corresponding values for France and Poland are 48 and 28 percent respectively, and are dominated by reduction of French nuclear power by 71 percent and of Polish hard coal power plants by 53 percent.

I consider investment in new gas combined cycle (CC), new gas fired gas turbines (Gas GT), new hard coal power plants (Hard Coal new) and the retrofit of old gas and oil fired units. The potential for retrofitting in a given period results from the age-based decommissioning of gas and steam turbines using oil or gas in the preceding decade. The same procedure is used to restrict investment in coal fired power plants.[10]

Table 2 shows assumptions regarding costs of investments for these technologies together with the essential technology characteristics in regard to efficiency, operation and maintenance (O&M), emissions and availabilities also of existing technologies. These parameters are by assumption constant over the assessed time horizon. Concerning investment and O&M costs our assumptions are based on the proposal of a data set for electricity market modeling by Schröder et al. (2013). However, since the decision to incur fixed O&M costs is taken in an intermediate time perspective between investment and dispatch, it is not modeled here. For the representation of fixed O&M costs, I therefore include ten years of discounted fixed O&M costs in the investment costs in case of new thermal power plants, while in case of hydro power fixed O&M costs are included in variable O&M costs. However, fixed O&M costs for old thermal power plants are excluded. Furthermore, I apply a discount rate of eight percent annually for the revenues from electricity supply over the model periods, where the second model period assumes a salvage value through an increased period weighting of 150 percent.[11] Schröder et al. (2013) also propose the documented efficiency degrees for new built power plants.

The outlined values for existing coal fired plants are taking age and technological development into account and are therefore below the efficiencies of the respective new built plants. Referenced emissions per output are based on these efficiencies and on standard fuel emission factors. The documented average annual availability factors including planned and unplanned outages refer to VGB (2012) and have been used to calculate reliable available capacities that are laid out in the previous table. Cost relevant parameters used for the model are completed by the assumptions of the German grid development plan 2013 regarding the increase of fuel and emission prices by 2023 and 2033, and are documented in Table 3. Based on these values and the parameters in Table 2, we get marginal costs of generation from existing hard coal of Euro 50 and 60 per MWh and from CC plants of Euro 55 and 60 per MWH in the periods 2023 and 2033 respectively.

Finally, international electricity flow is restricted by an average of the net transfer capacities that are published by ENTSOE (ENTSOE (2011a), ENTSOE (2011b)) and are summed over all interconnectors between each pair of countries. By assumption, these values are constant over the considered periods summarized in Table 4 below. It has to be noted that these values are only indicative values that do not reflect the grid expansion planned by the European Union.[12]

## 4. Results

The model is able to capture a wide range of aspects of the introduction of capacity remuneration schemes (CRMs) that depend on several characteristics of the electricity system in question. In the following, I highlight the welfare and distributional impacts of CRMs within and between countries and their development in time. I start out with a summary of results for the reference case of inelastic demand for the basic energy only market regulation and briefly comment on the impact of elasticity assumptions in the model. Based on the reference assumption, I develop the results for CRM options in two subsequent subsections. First, I feature and motivate effects on prices and remunerations, and the second part establishes the distributional and welfare consequences of CRMs.

[10] This assumption can be considered as mild since it turns out to be non-binding in the investigated scenarios.

[11] The corresponding fifty percent increase of the weighting of the last period is almost equivalent to a repetition of the second model period of ten years starting in 2043.

[12] See for instance the Ten-Year Network Development Plan of the European Network of Trans-mission System Operators for Electricity (ENTSO-E), URL: www.entsoe.eu/major-projects/ten- year-network-development-plan/tyndp-2014.

**Table 2**
Investment, O&M costs, degree of efficiency, emission factors and avail-abilities.

| | Investment [Mio. Euro/MW] | O&M [Euro/MWh] | Efficiency [%] | $CO_2$ [t/MWh] | Availability [%] |
|---|---|---|---|---|---|
| Nuclear | – | 10 | 33 | 0,0 | 81 |
| Lignite | | 7 | 41 | 1,0 | 85 |
| Hard Coal | – | 6 | 42 | 0,8 | 82 |
| Hard Coal new | 1,5 | 6 | 46 | 0,8 | 82 |
| Gas CC | 0,9 | 3 | 60 | 0,3 | 92 |
| Gas ST | – | 3 | 42 | 0,5 | 90 |
| Gas GT | 0,5 | 3 | 33 | 0,6 | 92 |
| Oil ST | – | 3 | 40 | 0,7 | 90 |
| Oil GT | – | 3 | 32 | 0,9 | 90 |
| Gas Retrofit | 0,4 | 3 | 44 | 0,5 | 92 |
| Hydro | – | 6 | 100 | 0,0 | 53[a] |

[a] Value for German plants; France: 32, Poland: 29.

**Table 3**
Input fuel and emission prices by 2023 and 2033.

| € | Nuclear | Lignite | Hard Coal | Natural Gas | Oil | $CO_2$ |
|---|---|---|---|---|---|---|
| | per MWh | | | | | per ton |
| 2023 | 6.0 | 1.5 | 9.7 | 26.0 | 51.2 | 25 |
| 2033 | 7.0 | 1.5 | 10.6 | 27.0 | 55.1 | 35 |

**Table 4**
Assumed maximum hourly interconnector capacities between countries in MW.

| From\To | De | Fr | Pl |
|---|---|---|---|
| De | inf | 3200 | 1000 |
| Fr | 2650 | inf | – |
| Pl | 1150 | – | inf |

**Table 5**
EOM: Average wholesale prices and profits and consumer rent (CR) in Germany, France and Poland by 2023 and 2033 for low (0.2; reference case) and high (0.4) elasticity in Euro per MWh.

| | | 2023 | | 2033 | |
|---|---|---|---|---|---|
| | | 0.2 | 0.4 | 0.2 | 0.4 |
| Price [€/MWh] | De | 50.7 | 49.8 | 61.2 | 59.0 |
| | Fr | 42.9 | 42.5 | 70.2 | 69.3 |
| | Pl | 50.1 | 50.2 | 66.0 | 62.0 |
| Profit [Bio €/a] | De | 16.7 | 16.4 | 24.2 | 23.2 |
| | Fr | 13.8 | 13.4 | 21.3 | 21.1 |
| | Pl | 2.7 | 2.7 | 5.6 | 4.9 |
| CR [Bio €/a] | De | 60.9 | 29.5 | 60.8 | 27.2 |
| | Fr | 66.9 | 34.0 | 57.2 | 22.0 |
| | Pl | 19.1 | 9.3 | 18.0 | 8.1 |

### *4.1. Reference results for Germany, France and Poland*

The simulation of the EOM regulation yields average prices, profits, and consumer rents for the three countries as laid out in Table 5. Profits are computed as difference between revenues and costs of generation and new investment in conventional capacities,[13] whereas the consumer rent (CR) is calculated as the difference of the willingness to pay of consumers, implied by the demand curve, and the market clearing price.

Considering the German case, we find average prices of around 51 Euro per MWh by 2023 and of about 61 Euro by 2033. Closely aligned in 2023, Polish and German prices diverge towards 2033 with Polish prices exceeding variable costs of hard coal power plants by about ten percent. Respective prices for France are about ten Euro lower by 2023 and about 10 Euro higher by 2033. The comparison of these prices with the variable costs of conventional generation implied by our cost assumptions[14] indicates a shift of the basic price determination from existing hard coal power plants in 2023 towards gas fired units in 2033. In combination with only modest price volatility,[15] the simulated price profile induces almost negligible margins of gas and hard coal power plants in the first model period. Thus, only lignite power in Germany and Poland as well as remaining nuclear plants in France generate significant margins for conventional generation that contribute to the profits laid out in Table 5.

By 2033, profits grow by between 40 and 100 percent due to frequent scarcity pricing that is determined by consumer's willingness to pay as opposed to marginal cost pricing. By 2023 however, the assumptions imply that conventional power plant investment under EOM regulation on top of renewable energy expansion is not profitable. The picture changes towards 2033 only on the French market, where significant investment corresponding with 25 GW of capacity is driven by the projected EOM market price development.

The impact of the elasticity assumption is found to be of minor importance. By 2023, assumption of a higher elasticity shows the most accentuated price effect on the German market, but average price dampening is below two percent compared to the reference elasticity. Notably however, prices in Poland are slightly higher if demand is more elastic. The intuition behind this result is based on strained international transmission capacity between Poland and Germany. In the high elasticity scenario the Polish prices converge more closely with German prices,[16] while in the reference elasticity case Poland can sustain substantially lower prices due to more frequent interconnection bottlenecks and export limitations. By 2033, elasticities play a slightly more prominent role particularly for the Polish market with an induced difference of six percent at average. The impacts on profits reflect these limited price effects, indicating sufficient robustness.

[13] We do not consider costs of renewable energy investments, since these are implicitly fixed by country targets and do not change in our investigated scenarios. A full cost representation of RES had to add controversial assumptions on variable costs of biomass power plants, and wind and solar costs in Poland and France. Thus, I refrain from an inclusion of RES supply, but note that the relative effects on profits induced by the different CRMs would change due to the level effect on reference profits under EOM. Similarly, costs of capital of existing capacities are not taken into account. This value is also assumed to be independent of the implemented policy.

[14] See data section above.

[15] See also Table a) in the Appendix for seasonal details on prices, which nevertheless imply a relatively steep merit order in France and Germany compared to the Polish system.

[16] Compare also with Table a) of the Appendix.

Please cite this article in press as: Traber, T., Capacity Remuneration Mechanisms in the Integrated European Electricity Market: Effects on Welfare and Distribution through 2023, Utilities Policy (2017), http://dx.doi.org/10.1016/j.jup.2016.10.005

### 4.2. CRMs and price effects on consumers and producers

The effects induced by the three policy instruments on electricity prices vary over time and, if a capacity market (CM) or strategic reserve (SR) policy with financing fees is introduced, between producers and consumers. By contrast, no differentiation between market participants accrues to the reserve capacity market (RM) policy, since no financing fee is necessary. However, the capacity certificate prices induced by the RM correspond to comparable payments for annual capacity provision as the other policies.

This is documented in Table 6, which shows the average annual capacity certificate prices of the RM, i.e. the average payments per MW per hour, in comparison to the corresponding payments by the SR and CM policies. By 2023, capacity certificate prices greatly diverge across countries due to differences in the most ex-pensive technology needed to source the reserves cost efficiently: In France, new gas turbines are required, while in Germany relatively inexpensive retrofitting determines capacity prices.[17] In Poland, the existing plant stock is sufficient to source reserves requirements by 2023 with correspondingly low capacity prices. Capacity payments necessary for the SR policy vary less pronounced since investments are necessary for all countries, although a lower payment applies to Poland due to suf-ficient retrofitting options. By contrast, a CM policy requires investment in more expensive gas turbines across all countries, thus leading to equal payments already by 2023. By 2033, the marginal investments triggered across policies and countries are new gas turbines so that the average capacity payments are identical.

The different necessary payments as well as volumes of payments lead to a greatly varying impact on prices. This is reflected in Fig. 2 summarizing price effects for consumers (dots) and producers (dark bars), and necessary financing fees (light bars) by 2023 and by 2033 due to the three policy options.

#### 4.2.1. Strategic reserve

The first three entries on the vertical axis of Fig. 2 represent the effects of the SR policy and show that consumer price effects vary across counties by about a factor of three. The SR effect on consumer prices is the sum of producer price effect and financing fee, and both components turn out to be country specific.

The economic intuition is as follows. First, differences in producer price effects stem from the reduction of generation in existing capacity used as strategic reserve. This explains high producer price increases in Germany and Poland where the majority of the reserves are existing units. In contrast, most of the strategic reserve in France consists of new built plants, which do not affect wholesale electricity prices. Second, differences in the necessary fees relate to differences in the payment per capacity shown above, and the volume of the reserves in relation to the market demand. A high share of reserves appears necessary in Germany where the fast photovoltaic rollout induces a particularly large share of non-reliable price-inelastic capacity that leads to a significant increase of peak load. The phase-out of major nuclear energy generators contributes to this situation. Consequently, the capacity volume and the necessary fees are larger in Germany compared to France and particularly to Poland, i.e. in countries where the assumed photovoltaic expansion is much lower.

Towards 2033, we find no substantially increasing consumer price effects of the SR in France and Poland, and a further increase

[17] A comparison with Fig. 4 in the last subsection shows the investment effect of policies and motivates this assessment. However, investment effects not fully correspond with reserves.

**Table 6**
Average hourly payments per firm capacity [Euro/MWh] by the CRMs.

| | | SR | CM | RM |
|---|---|---|---|---|
| 2023 | De | 4.6 | 4.6 | 2.7 |
| | Fr | 4.6 | 4.6 | 4.6 |
| | Pl | 2.7 | 4.6 | 0.6 |
| 2033 | De | 5.7 | 5.7 | 5.7 |
| | Fr | 5.7 | 5.7 | 5.7 |
| | Pl | 5.7 | 5.7 | 5.7 |

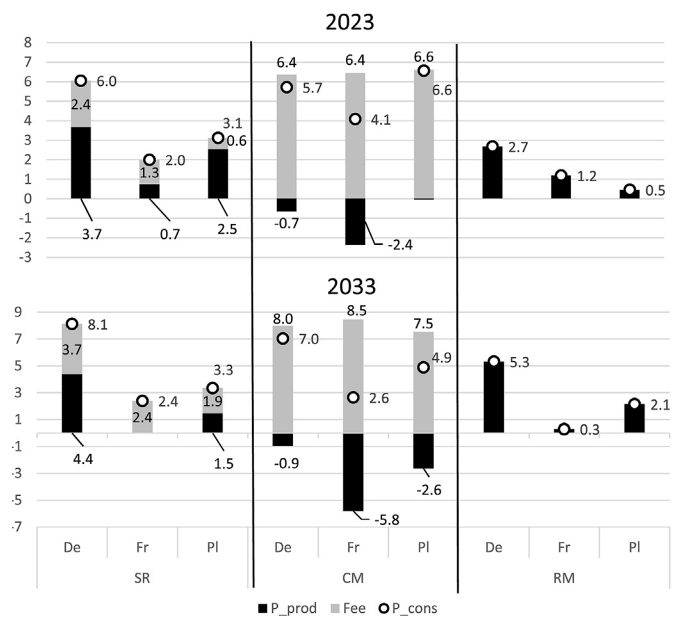


**Fig. 2.** Policy impacts of CRMs on consumer and producer prices, necessary fees, and average RM prices in Euro per MWh by 2023 (upper figure) and 2033 (lower figure).

in Germany. This structure is explained by a reduction of producer price effects in France and Poland, and a further increase of producer price effects in Germany: In France and Poland, reserves are mainly consisting of new plants, while in Germany substantial existing hard coal units are withdrawn from the energy market by the SR.

#### 4.2.2. Capacity market

Similar to SR policy, the centralized capacity market (CM) induces consumer price effects that are summing up producer price effects and fees. However, the producer price effect of a CM is (weakly) negative, as can be observed from the three columns in the middle of Fig. 2. The explanation for this result is the abolishment of scarcity prices that are determined by the marginal willingness to pay of consumers. The CM rather induces a system of full merit order pricing reflecting the marginal generation costs of the last supplied unit.

The inverse of this result is that by 2023 in Germany and France substantial scarcity prices under EOM are depressed by the CM (negative producer price effects in column CM of 2), whereas in Poland merit order pricing is expected to last at least until 2023 in the absence of policies. This picture changes by 2033 since capacities in Poland and France are getting scarce under EOM, which is indicated by substantially negative producer price impacts induced by the introduction of the CM policy. By contrast, the CM policy induces in Germany only weak reductions of producer prices, which can be explained with the relative abundance of renewable

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energy supply.

Concerning the CM fees, we find only minor differences across countries. This is due to per unit capacity payments that are identical in all countries as is shown in 6 below. The reason is that marginal investment technology to achieve the reserve requirements of the CM are in all countries new built gas turbines. Moreover, since the remunerations are paid to all necessary firm capacities, the changes induced by demand response are of minor impact compared to the other policy options. Consequently, the country specific ratio between the peak load and consumption is less influential and explains the only minor differences in CM related fees across countries.

### 4.2.3. Reserve obligations with capacity certificates

Results for the RM's price effects are documented in last three columns of Fig. 2, which are identical to producer and consumers. They depend on the reserve capacity certificate prices, their dampening effect on load peaks and the corresponding reduction of wholesale market prices net of certificate costs. We find substantial differences of producer price effects across countries. These differences are explained by differences in necessary prices to adapt load to firm capacity. Due to a large share of fluctuating energies in Germany, a comparatively pronounced price signal is necessary. By 2023, this contrasts with the result for Poland where the majority of power plants are reliable and consequently only a small price signal is necessary for demand adaptation. Moreover, it appears that by 2033 the price effects of the RM almost vanish in France, which is explained by pronounced scarcity pricing under EOM sufficient to finance major investment in power plants.

## 4.3. Impacts on distribution and welfare

The fees and capacity remunerations as well as changes of consumer and producer prices translate into shifts in the components of welfare separated into consumer rents, revenues, variable costs and investment costs. For the different CRMs, Fig. 3 shows the contributions of these components to the change of welfare in billions of Euro (bars, lefts scale) together with the relative changes in percent (dots, right scale) compared to the EOM reference case and separated into the three countries.

On the one hand, throughout the three CRMs reductions of variable costs and increased revenues contribute to positive impacts on welfare in the form of additional operating profits of supply shown as positive parts of the bars in 3. Intuitively, variable costs savings are explained by the consumer price increases that depress demand and production, while the increase of revenues is explained by comparatively inelastic demand.

On the other hand, welfare reductions are due to reduced consumer rents and increased investment costs, and over-compensate the positive effects as indicated by negative welfare changes for all cases of CRMs[18]. Clearly, effective policies tend to trigger additional power plant investments and therefore increase total costs, while price increases compared to the laissez-faire of an EOM reduce consumer rents.

### 4.3.1. Distributional effects

Comparing the volume of distributional impacts across CRMs and countries, it turns out that they are highest in Germany. Due to larger consumer price increases, the impacts on German consumer

[18] Note that these are the welfare effects without accounting for the benefits of increased system security due to a five percent reliability margin. Hence, this modeling exercise does not answer the question whether a CRM is overall welfare improving.

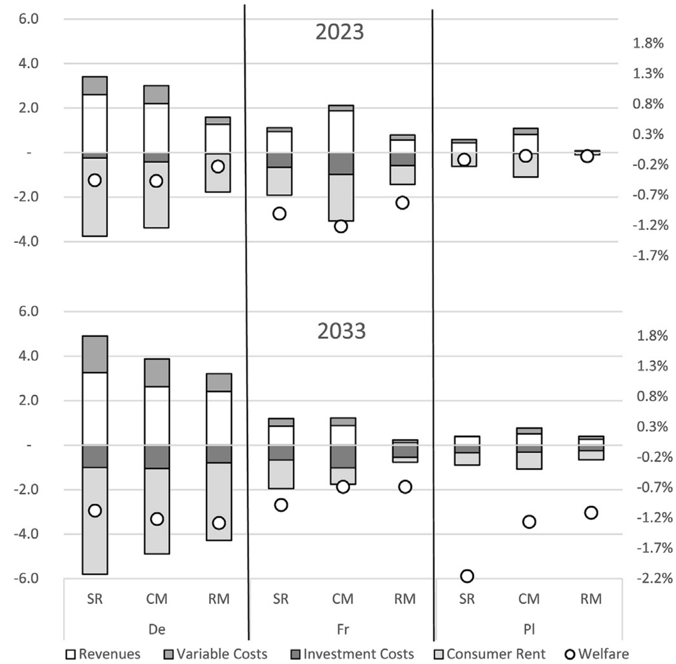


**Fig. 3.** Effects of CRMs on consumer rents, revenues, costs (left scale; billions of Euro), and welfare change relative to EOM (right scale) separated into countries by 2023 (upper figure) and 2033 (lower figure).

rents are comparatively large despite a smaller market volume compared to the French market. Moreover, the strong price effects correspond to particularly huge increases in operating profits of German producers. For the RM policy, an explanation is the particularly strong producer price increases due to reserve requirements given a comparatively steep merit-order curve[19]. In case of the CM, the pronounced profit increases are due to the large payments to all firm capacity with only modest dampening effects on producer prices as shown in Fig. 2 of the previous subsection.

Regarding the case of the SR, the intuition is found in the combination of large reserve payments - indicated by comparatively high fees in Germany - with pronounced price increases triggered by the withdrawal of capacity from a market with a steep merit-order curve. Conversely, a comparatively flat merit-order curve leads to only moderate producer price effects in Poland, and distributional effects are mainly explained by the fees for CM and SR payments. Considering the size of the Polish market of about a fourth of the French market, the total distributional effect in Poland appears comparatively large, and particularly pronounced under a CM regime.

The comparison of distributional effects within countries based on 2 reveals lowest RM shifts for the investigated country group for both periods. As a main result this corresponds to a clear advantage of RM policy for consumers, which is explained by the scarcity signals that induce a dampened peak load development. By contrast, the other two policies induce ambiguous distributional effects and impacts for consumers across markets and time periods.

### 4.3.2. Welfare effects

The corresponding welfare effects diverge substantially across countries and only loosely correspond to the volume of distributional effects. Rather, we find that the volume of distributional

[19] Compare with Table a) of the Appendix.

effects translate country specific into welfare effects.

Focusing on 2023, the comparison across countries based on Fig. 3 shows lower welfare effects in Germany compared to France, despite larger distributional volumes. This observation is best explained by the substantial firm capacity investment triggered by CRMs in France. Conversely, in Poland welfare effects are modest de-spite substantial distributional effects, since additional investments are low. Thus, regarding the first period diverging investments justify substantial differences in welfare effects across countries. However, comparing different CRMs within a country shows a clear relationship between welfare reductions and the size of the distributional effects within countries, i.e. the larger the total size of the bars shown in the upper graphic of Fig. 3 the more pronounced are the welfare losses in each country.

By 2033, welfare effects tend to increase in Germany and Poland, while they are more stable in France. The interpretation is that by 2033 all the investigated markets trigger large additional investments based on the same payments resulting in similar welfare effects, whereas by 2023 only the French market requires comparable plant investment at high payments as is observable from Table 6 and Fig. 4.

From a welfare perspective, the comparison of CRMs shows a clear dominance of the RM policy by 2023 since it induces the least pronounced welfare reductions across countries as is documented in Fig. 3. This finding is explained by the modest impact on consumer rents due to comparatively low investment needs. These Are in turn a consequence of the increased scarcity pricing and its dampening impact on peak demand and reserve requirements.

However, by 2033 the welfare comparison becomes ambiguous. On the Polish and French markets, the RM keeps its preferable low impact, but on the German market the SR turns out to be least welfare reducing despite larger investment needs and stronger consumer price increases compared to the RM. This finding rests on the lower uptake of operating profits due to RM compared with the SR. By contrast, the SR policy performs least preferential in the long term in France and Poland, which is explained by the increasing amount of costly investments that are not available for generation.

## 5. Discussion

Based on the modeling results, a reserve obligation shows preferable outcome at least for the period 2023. We find the smallest distributional impacts due to a RM, while the policies of CM and SR show mixed results. Moreover, the cumulated welfare impacts of the policies tend to converge, which is apparent from comparison of the impacts of CRMs on welfare in Germany for both periods (Fig. 3), where the ranking of the policies is almost completely reversed. In addition, there are some limitations to the analysis conducted in the present work.

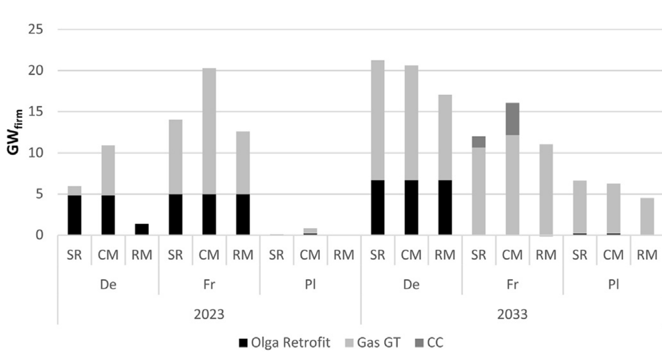


**Fig. 4.** Effects of CRMs on investment in firm capacity across countries by 2023 (left) and 2033 (right).

Firstly, we model an ideal RM without frictions. This concerns information requirements and the potential abuse of market power. To coordinate the efficient allocation of reserve capacity among hundreds of potential suppliers, intermediaries and demand on hourly basis may involve significant transaction costs, which may add to certificate prices. Furthermore, a small number of suppliers that control a large part of firm plant capacity may dominate the certificate market. Thus, an advanced policy recommendation would have to consider potential market power problems. Moreover, the monitoring of capacity obligations may induce significant costs for the regulator, and poses the problem of determining a penalty for insufficient performance.

Secondly, the model simulation uses perfect foresight. This reduces necessary payments for investment under political or market induced uncertainty and risk averse investors. This constitutes a considerable problem in existing capacity markets at least in the US as is stressed in Bowring (2013). Furthermore, the model neglects the costs due to unpredicted demand developments with necessary readjustment of capacity targets under the SR or CM in order to keep a fixed target for the reserve margin. The related risk could lead investors to demand further risk premiums under the regulations with absolute capacity targets.

Thirdly, our reference energy market regulation of EOM does not provide incentives to supply firm capacity, although most energy markets have further regulations for the reliability of the electricity system. For instance, in Germany suppliers are obliged to balance electricity provision and sales ex post. If demand is not supplied by procured generation, companies have to pay for necessary balancing capacities. This provision leads to income for balancing capacities either on the balancing market or within companies to prevent balancing energy payments, and provides some level of firm capacity in the current regulatory framework. Moreover, the model does not attempt to quantify the value of reliability and the costs of supply interruptions, which is necessary to shed light on the question whether a CRM is indicated. Consequently, robust policy conclusions need a more elaborated picture, which includes a larger variety of aspects.

An example is the withdrawal of coal power plants from the energy market as simulated for the SR policy, which may have considerable environmental consequences. Moreover, CRM policy impacts rely on the international transmission pricing regime and how international interconnectors are rated as is emphasized by Newbery (2016). In addition, CRM policies threat to undermine renewable energies by transfers to fossil generators and may also impede incentives to build transmission infrastructure and to improve the European internal market as pointed out by Newbery and Grubb (2015). Moreover, Newbery (2016) argues that CRMs have the potential to self-fulfill the prophecy of missing money in liberalized markets, which they were intended to cure. This finding is also supported by the present analysis, which shows that scarcity prices are completely erased by a central capacity mechanism. A strategic reserve has the advantage that it may focus on a small market segment and therefore is more likely to be reversed if reliability concerns are fading as has been pointed out by Lehmann et al. (2015). Interconnectors, grid capacities, storage facilities, and demand side response are alternatives for the provision of reliability that are much harder to rate than firm fossil power plant capacity, but have to be included in a market approach that has the chance to deliver efficiently.

## 6. Conclusion

I develop a multi-period market and investment model of the central European regions Germany, France and Poland to analyze

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effects of the introduction of different capacity remuneration mechanisms and highlight distributional effects from consumers to producers with a focus on conventional power plants. Moreover, a welfare analysis of a strategic reserve (SR), a simple capacity market (CM) and a reserve obligation with a capacity certificate market (RM) is conducted. I find that impacts of policies largely arise due to the existing generation structure of the analyzed markets and their development in time. Given the assumption that a CRM is necessary, the RM policy is preferred at least in the period 2023. In addition, the distributional effects of a RM turn out to be minor, and induce lower price increases for consumers compared to the SR and the CM.

The welfare effects of SR and CM are ambiguous, since they more closely depend on the specific merit-order curves, which change over time and across countries. Finally yet importantly, I find long term cumulated welfare impacts of the CRMs that do differ less pronounced compared to either single period. Thus, the insights from the analysis suggest supplementation by further analysis before drawing final policy conclusions. This concerns the potentials of further policies, which are for example based on regulations for auxiliary services and on further technological options, e.g. demand side management, grid enforcement and transmission capacity enhancement. Furthermore, advances in the field of energy storage technologies are rapid and suggest that an assessment of further technology potentials for the provision of reliability is necessary before introducing policy measures that are hard to cancel.

The research conducted for this paper provides a basic tool for the analysis of further aspects concerning policies for capacity reliability. Important issues for the future research agenda include the analysis of potential market power aspects in CRM markets, the detailed impacts of policies on competitiveness of renewable energies, and the asymmetric introduction of policies across European countries and their trade effects.

## Acknowledgements

Financial support by the Mercator foundation by the project MASMIE and by Norden through the project Flex4RES are gratefully acknowledged. I am indebted to participants of the Berlin Seminar on Electricity 2014 for helpful comments. All remaining errors are the author's sole responsibility.

## Appendix

Table a) EOM average and peak prices across seasons and countries by 2023 and 2033 for reference (0.2) and high elasticity (0.4).

| | | | Average Pri | | | ce | | Peak price | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Annual | S1 | S2 | S3 | S4 | S1 | S2 | S3 | S4 |
| 0.2 | 2023 | De | 51 | 52 | 51 | 50 | 73 | 55 | 55 | 50 | 109 |
| | | Fr | 43 | 67 | 45 | 28 | 81 | 101 | 55 | 30 | 116 |
| | | Pl | 50 | 51 | 50 | 50 | 53 | 55 | 50 | 50 | 59 |
| | 2033 | De | 61 | 61 | 63 | 60 | 112 | 77 | 93 | 60 | 171 |
| | | Fr | 70 | 91 | 68 | 60 | 117 | 139 | 93 | 60 | 171 |
| | | Pl | 66 | 74 | 65 | 62 | 105 | 119 | 96 | 70 | 139 |
| 0.4 | 2023 | De | 50 | 51 | 50 | 49 | 65 | 56 | 55 | 50 | 92 |
| | | Fr | 43 | 59 | 45 | 32 | 66 | 88 | 55 | 42 | 92 |
| | | Pl | 50 | 51 | 50 | 50 | 52 | 56 | 50 | 50 | 55 |
| | 2033 | De | 59 | 59 | 61 | 58 | 85 | 71 | 77 | 60 | 125 |
| | | Fr | 69 | 87 | 71 | 59 | 97 | 124 | 101 | 64 | 133 |
| | | Pl | 62 | 66 | 62 | 60 | 79 | 94 | 77 | 61 | 99 |

Table b) CRM impacts on average seasonal producer prices in Germany by 2023 and 2033 for reference (0.2) and high elasticity (0.4).

| | | 2023 | | | | 2033 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 0.2 | | 0.4 | | 0.2 | | 0.4 | |
| | | Prod | Cons | Prod | Cons | Prod | Cons | Prod | Cons |
| SR | Annual | 3.7 | 6.0 | 1.7 | 3.0 | 4.4 | 8.1 | 4.0 | 8.2 |
| | Winter | 9.6 | 12.0 | 5.2 | 6.5 | 8.5 | 12.2 | 7.3 | 11.4 |
| | Shoulder | 3.7 | 6.0 | 1.6 | 2.9 | 4.7 | 8.4 | 5.6 | 9.8 |
| | Summer | 0.2 | 2.6 | −0.3 | 1.0 | 1.9 | 5.6 | 1.3 | 5.4 |
| | Extreme | 34.6 | 37.0 | 13.6 | 14.9 | 23.4 | 27.2 | 18.0 | 22.2 |
| CM | Annual | −0.7 | 5.7 | −2.0 | 4.7 | −0.9 | 7.0 | −2.3 | 6.5 |
| | Winter | −0.6 | 5.8 | −2.4 | 4.3 | −1.3 | 6.7 | −2.5 | 6.3 |
| | Shoulder | −0.6 | 5.8 | −1.5 | 5.2 | −1.6 | 6.3 | −2.4 | 6.4 |
| | Summer | −0.7 | 5.7 | −2.1 | 4.7 | −0.2 | 7.8 | −2.2 | 6.7 |
| | Extreme | −4.8 | 1.5 | −5.0 | 1.8 | −25.5 | −17.5 | −10.3 | −1.4 |
| RM | Annual | 2.7 | | 2.1 | | 5.3 | | 5.0 | |
| | Winter | 8.9 | | 6.1 | | 16.0 | | 12.1 | |
| | Shoulder | 1.3 | | 1.4 | | 2.6 | | 3.9 | |
| | Summer | 0.0 | | 0.2 | | 1.1 | | 1.8 | |
| | Extreme | −1.7 | | −0.6 | | −17.3 | | −5.1 | |

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## Abbreviations

*CRM:* Capacity remuneration mechanism
*EOM:* Energy only market regulation; indicating the baseline without capacity policy
*CM:* Capacity market; indicating administratively implemented capacity market
*RM:* Reserve obligation with capacity certificate market
*SR:* Strategic reserve; indicating administratively implemented reserve capacity policy
*BC:* Brown coal power plant
*CC:* Combined cycle gas power plant
*GT:* Gas turbine power plant, e.g. Gas GT
*HC:* Hard coal power plant
*ST:* Steam turbine power plant, e.g. Gas ST
*SC:* Single cycle
*Olga Retrofit:* Retrofitted oil or gas power plant
*S1:* Winter season
*S2:* Shoulder season
*S3:* Summer season
*S4:* Low wind event in winter season
*De:* Germany
*Fr:* France
*Pl:* Poland