

A real options approach to generation capacity expansion in imperfectly competitive power markets

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Received: date / Accepted: date

Abstract This paper proposes a real options approach to generation capacity expansion in imperfectly competitive power markets. Our framework incorporates firms with different levels of market power; heterogeneous technologies, including renewables, base load and peak load; time-varying short-term demand and renewable supply; and long-term demand uncertainty. A real options model allows us to obtain technology-specific thresholds for demand to trigger investment. We apply our model to the German power market and show that a doubling of current demand triggers renewable investment, whereas base load generation requires over 50 times current demand on average. The availability of peak load generation serves to avoid rationing and reduce fluctuations in the electricity price. In the absence of incentive mechanisms, however, demand does not become sufficiently high to trigger investment in this technology. We investigate at which level capacity payments to peak power plants prevent rationing without reducing investments in renewables. Furthermore, by accounting for market power, we illustrate that strategic firms do not increase their market shares over time but hold back investment until market prices are sufficiently high for price-taking firms to expand capacity. As a result, the intensity of competition increases over time.

Keywords Capacity expansion · Competitive power markets · Energy systems · Real options

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1 Introduction

During the past decades, European electricity markets have been largely deregulated, see [37]. Power is now produced by private companies that observe market prices and maximize their profits accordingly. The generation of electricity, however, creates a feedback effect on the price, see [19]. Furthermore, in many countries, mergers and acquisitions have resulted in markets with few suppliers having high market shares and thereby opportunities to exercise market power and impact market prices [42].

A number of papers provide empirical evidence of market power in electricity markets. Examples include [41] and [50], both showing significant mark-ups on competitive electricity prices in Germany from 2001 to 2003. The latter argues that mark-ups were nearly 50%, whereas the former indicates that market power was declining during 2004 and 2005. For further evidence of prices above competitive levels in Germany, see also [67]. [34] likewise documents the exercise of market power in the German electricity market during the period 2006 to 2008, but also observes an increase of market competitiveness over time. [Despite this increase, newer studies continue to show clear indications of market power. \[36\] analyses stochastic arbitrage opportunities between the German spot and balancing markets from 2009 to 2011 and confirms that strategic behavior exists, with under and oversupply of up to 80%. \[64\] considers the day-ahead and real-time markets in the Nordic region during 2010 to 2013 and rejects the hypothesis that the Nord Pool market was characterized by perfect competition in all price areas.](#)

Recently, the power system have also experienced an increasing penetration of renewables, see [1]. As renewable production is highly fluctuating, this may generate a high level of supply risk, cf. [14]. Moreover, if the supply side consists of technologies with low operational costs such as renewables, the electricity price will approach zero, cf. [62], and capacity investments will no longer be attractive. In particular, with the growth in renewables, gas-fired generation becomes increasingly unprofitable, [26]. Nevertheless, a high renewable penetration accentuates the need for flexible buffer capacity, as pointed out by [23].

To solve this problem, [20] suggests that the power-producing technology with the lowest fixed costs and the best ramping properties should receive capacity payments, favoring gas-fired power plants. This view is supported by [5] and [23]. Also, [38] argues that gas-fired power plants represent the fossil fuel generation technology with the least greenhouse gas emissions. At the same time, [7] stresses that care should be taken that capacity remuneration mechanisms (CRMs) for conventional power plants do not crowd out renewables.

In view of deregulation and renewable growth, this paper revisits existing real options models for capacity expansion and explore their potential in the new context of market power and emerging technologies. Real options analysis have been applied to a variety of investment problems under uncertainty, e.g. [46], [53] and [8]. For capacity expansion problems in power markets, real options models allow for the valuation of flexibility in both operation and investment, which is a great advantage over the traditional static net present value assessments.

Investments in power generation equipment are capital intensive, and the equipment is difficult to sell once installed. As a result, investment decisions are often con-

sidered to be irreversible. Furthermore, capacity expansions are rarely now-or-never decisions, cf. [9]. On the contrary, investment can be delayed until the company has sufficient information about future market conditions such as demand. By taking a real options approach to capacity expansions in the power sector, we account for the value of postponing irreversible investment decisions, as [48], [40], [13], [69] and [6].

Alternative approaches to dynamic investment optimization under uncertainty include mathematical programming. An example is [43] that proposes a large-scale, concave, linearly constrained mathematical program for long-term power generation expansion planning. Mathematical programming can incorporate many details in modeling such as unit commitment, retirement of equipment, elastic demand and a representation of the transmission network. We likewise include retirement decisions and elastic demand. For simplicity, we do not account for transmission constraints. Yet, our model could be extended to incorporate such features. In contrast, the inclusion of start-up restrictions would make our approach significantly more complex, as we do not allow for dynamic short-term constraints. In contrast to other optimization approaches, however, the continuous-time real options methodology facilitates the explicit derivation of investment thresholds and thereby provides direct decision rules for investment. In particular, our real options model allow us to obtain technology-specific thresholds, above which demand is sufficiently high to justify investment.

Traditional real options models consider the value and timing of a single investment opportunity. Such models often provide closed-form solutions. Nevertheless, their assumptions fit poorly with actual power markets. As advocated by [19], these models rely on numerous simplifications, including an exogenous electricity price. More specifically, by neglecting the system dispatch they fail to capture the impact on the price of strategic interaction between firms. Several papers have modeled power markets as oligopolies, e.g. [35], [30], [68] and [18]. In line with this modeling tradition, we cast the simultaneous dispatch problem of a number of firms as an equilibrium problem. To capture the characteristics of actual power markets in a real options context, we may cast the capacity expansion problem by stochastic control or canonical real options. The stochastic control approach is examined by [35] and [68]. Control models may incorporate an endogenous electricity price, but become intractable in a stochastic continuous-time setting. Canonical models, on the other hand, support a stochastic setting, allow for an endogenous electricity price, cf. [58], and are less difficult to solve. These models consider a series of incremental capacity expansions, see [19].

A drawback of canonical real options models is that tractability is due to myopia, cf. [3]. With myopia, the investment in additional capacity is to be the last over the time horizon. The assumption of myopia requires symmetric generation technologies in the power market as in [25], or additive separability of the profit function as in [24]. Yet, investment, maintenance and marginal costs vary between technologies and their dispatch is linked through the impact on the electricity price. Hence, myopia may not hold for our problem. In spite of this, we use this as an assumption to facilitate a solution. We argue that myopia is an acceptable approximation, given the behavior of many firms in practice. If an investment is attractive, it is to be the last over a foreseeable future. As time passes and electricity demand changes, a new investment

might be undertaken, despite the earlier assumption of the previous investment to be the last.

An important task of real options analysis is the modeling of uncertainty. Earlier works on the modeling of electricity prices include [60], [54], [44] and [15]. These papers model an exogenous long-term electricity price as a geometric Brownian motion. Although price models could be much more advanced, [54] argues that modeling the long-term evolution of commodity prices by a geometric Brownian motion results in only small errors. To include price feed-back, [19] suggests an inverse demand curve which is subject to a shock driven by a geometric Brownian motion. We adopt this approach.

Despite the clear need for a better understanding of capacity expansions in today's power markets, there is a limited amount of academic literature addressing market power and renewable penetration. We contribute to filling this gap by extending the capacity expansion model of [19] to account for the following particularities in a real options context:

1. We treat electricity as a differentiated product, both between years and within each year. Fluctuations in short-term demand and non-controllable supply are modelled by dividing each year into a number of time segments, using the same procedure as in [4].
2. We model a number of generation technologies that differ in marginal, maintenance and investment costs. Moreover, we categorize the technologies into controllable and non-controllable power sources. Controllable power plants can produce electricity within the limits of installed capacity. For non-controllable power plants, generation is determined by normalized production times installed capacity.
3. We model an actual power market in which firms have different levels of market power. Firms are divided into two categories; with and without market power. The firms with market power are modelled as Cournot firms, such that they can affect the electricity price through their own dispatch while taking the dispatch of the other firms as given. In contrast, the firms without market power are price-takers.
4. The simultaneous dispatch problem is formulated as an equilibrium problem that can handle the feedback effect of production on the market price.

Our solution approach likewise follows the lines of [19], combining closed-form solutions to the real options problems with Monte Carlo simulations. We generate a number of simulation paths of yearly demand shock realizations throughout the time horizon. For a given year and a given realization of the shock, we fix the installed capacity and solve a number of equilibrium problems that determine the dispatch of the firms in all time segments. We use the Lagrangian multipliers of the equilibrium problems as proxies for the profits accruing during a segment upon installing a unit of additional capacity and we compute expected future profits. Profits are regressed on functions of the current demand shock which allows us to solve the incremental capacity expansion problem analytically. If investment is profitable, installed capacity is updated.

To validate our capacity expansion model and assess its performance, we consider a case study of the German power market, containing a diverse energy mix.

Table 1: Nomenclature. Sets, parameters and variables of the capacity expansion equilibrium.

| sets | | |
|-----------------------|---|------------------------|
| F | firms | |
| K | technologies | |
| K_{nc} | non-controllable generation technologies | |
| K_c | controllable generation technologies | |
| H | time segments of the year | |
| parameters | | units |
| ρ | annual discount rate | % |
| Y_t | industry-wide demand shock in year t | |
| μ | trend | |
| σ | standard deviation | |
| a_h | intercept of the inverse demand curve | €/MWh |
| b_h | slope of the inverse demand curve | €/h/(MWh) ² |
| d_h | duration of segment h | h |
| Q_h^{min} | inelastic demand in segment h | MW |
| c_k | unit production cost for technology k | €/MWh |
| I_k | investment cost of technology k | €/MW |
| c_r | unit cost of rationing | €/MWh |
| $Z_{k,h}$ | normalized non-controllable generation from technology k in segment h | % |
| $Q_{f,k}^{max}$ | maximal accumulated production of firm f and technology k | MW |
| variables | | units |
| $D_h(\cdot)$ | inverse demand in segment h | MW |
| $P_h(\cdot, \cdot)$ | market price in segment h | €/MWh |
| v_h | security of supply premium in segment h | €/MWh |
| ζ_h | balancing cost or premium in segment h | €/MWh |
| $K_{f,k}$ | capacity of firm f and technology k | MW |
| K | capacity matrix with entries $K_{f,k}$ | MW |
| $q_{f,k,h}$ | dispatch of firm f and technology k in segment h | MW |
| $q_{f,h}$ | total dispatch of firm f in segment h | MW |
| Q_h | total dispatch/demand of all firms in segment h | MW |
| $q_{r,h}$ | rationing in segment h | MW |
| $\mu_{f,k,h}$ | multiplier of the capacity constraint for non-controllable generation of firm f and technology k in segment h | |
| $\lambda_{f,k,h}$ | multiplier of the capacity constraint for controllable generation of firm f and technology k in segment h | |
| $\delta_{f,k}$ | multiplier of instantaneous production constraint of firm f and technology k | |
| $\gamma_{f,h}$ | multiplier of accumulated production constraint of firm f in segment h | |

The paper is structured as follows. In Section 2, we introduce our capacity expansion problem. We present our model parameters in Section 3. Section 4 contains an illustrative example and Section 5 considers a case study of the German power market. Finally, Section 6 concludes.

2 The capacity expansion model

We now introduce the capacity expansion model, see the nomenclature in Table 1.

2.1 Fluctuations in demand and supply

We formulate our model in continuous time. To distinguish between long-term and short-term time horizons, however, we refer to dynamics between years and within each year, respectively.

In a multi-decade analysis, it is important to capture long-term uncertainty in the technological and societal developments that has a permanent impact on supply and demand of the power sector. In a capacity expansion context and with special emphasis on analyzing price feedback effects, uncertainty in electricity demand is crucial. We model long-term fluctuations in demand by an industry-wide yearly shock $\{Y_t : t \geq 0\}$ that follows the geometric Brownian motion

$$dY_t = \mu Y_t dt + \sigma Y_t dz_t, \quad t \geq 0, \quad (1)$$

where μ is the yearly trend, $\sigma > 0$ is the yearly standard deviation and dz_t is an increment of a Wiener process. We assume that Y_0 is known.

We treat electricity as a differentiated product between years and within each year, [28]. Short-term fluctuations in load and weather-driven renewable supply are accounted for by dividing a year into a number of time segments. The set of all time segments within a year is denoted by \mathbf{H} . Each segment $h \in \mathbf{H}$ is defined by levels of load, wind production and solar production and its duration is denoted by d_h .

We let fluctuations in the electricity price be subject to both short-term and long-term fluctuations in demand and supply. For each segment $h \in \mathbf{H}$, we model the short-term impact of production on the price by a decreasing inverse demand function. We denote the function by $D_h(\cdot)$ in segment h . As justified by [9], we assume the electricity price $P_h(\cdot, \cdot)$ in segment h is determined by the product of the industry-wide shock and inverse demand. The electricity price of year t and segment h is then given by

$$P_h(Y_t, Q_h) = Y_t D_h(Q_h). \quad (2)$$

2.2 Dispatch

We start by taking a short-term perspective. For a given year t and a given realization of the demand shock $Y_t = Y$, we fix the installed capacity and determine the dispatch of the system in all time segments. To capture the characteristics of an actual power market, we cast the simultaneous dispatch problem of a number of firms as an equilibrium problem.

As advocated in the introduction, power systems have heterogeneous generation technologies and firms with different levels of market power. We denote the set of technologies by \mathbf{K} and the set of firms by \mathbf{F} . Firm $f \in \mathbf{F}$ has capacity $K_{f,k}$ of technology $k \in \mathbf{K}$. The capacity $K_{f,k}$, is an entry of the capacity matrix $K = \{K_{f,k} : f \in \mathbf{F}, k \in \mathbf{K}\}$. In the dispatch problem, K is therefore fixed. We divide the set of technologies \mathbf{K} into two subsets, \mathbf{K}_{nc} and \mathbf{K}_c . Subset \mathbf{K}_{nc} represents non-controllable generation technologies and subset \mathbf{K}_c covers controllable generation technologies.

To formulate the dispatch problem, we let $q_{f,k,h}$ be the dispatch of firm f and technology k in segment h and $q_{f,h}$ be the total dispatch of firm f in segment h , i.e. $q_{f,h} = \sum_k q_{f,k,h}$. Moreover, we let Q_h be the aggregate dispatch of all firms in segment h such that $Q_h = \sum_f q_{f,h}$. In equilibrium, each firm $f \in \mathbf{F}$ determines its optimal dispatch by profit-maximization. We assume that the market consists of $|\mathbf{F}| - 1$ Cournot firms that are able to exercise market power, and a number of price-taking firms with non-strategic operational behavior. To avoid separate handling of many identical firms, the price-taking firms are aggregated into one competitive fringe, $f = |\mathbf{F}|$. Being a price-taker, its dispatch does not affect the price, and so

$$\frac{\partial P_h}{\partial q_{|\mathbf{F}|,h}}(Y, Q_h(q_{|\mathbf{F}|,h})) = 0, \quad h \in \mathbf{H}. \quad (3)$$

The Cournot firms consider a negative feedback effect on the price through their own dispatch while taking the dispatch of the other firms as given. Hence, we assume that

$$\frac{\partial P_h}{\partial q_{f,h}}(Y, Q_h(q_{f,h})) = \frac{\partial P_h}{\partial Q_h}(Y, Q_h) < 0, \quad h \in \mathbf{H}, f = 1, \dots, |\mathbf{F}| - 1. \quad (4)$$

Below, we present the profit maximization problem that determines the optimal dispatch of firm f . The objective (5) accumulates operating costs $\sum_k c_k q_{f,k,h}$ of firm f in segment h , where the unit production cost for technology k is denoted by c_k . It further includes revenues in segment h , which are a function of firm f 's dispatch in segment h , $q_{f,h}$, and the duration of the segment, d_h . Per unit revenues are determined by the market price $P_h(Y, Q_h(\cdot))$ and a premium v_h for contributing to meeting demand and thereby avoiding rationing. Generation from non-controllable energy sources is determined in (6), where $Z_{k,h}$ is the normalized production from technology k in segment h . This constraint implies that non-controllable production of technology k by firm f in segment h equals normalized production times the capacity installed. Equations (7), (8) and (10) constrain controllable instantaneous and accumulated generation to be within its upper limits, $K_{f,k}$ and $Q_{f,k}^{\max}$, respectively, and be non-negative. For some technologies, $Q_{f,k}^{\max} = \infty$, whereas yearly hydropower production is limited by the availability of water and so, $Q_{f,k}^{\max} < \infty$. Constraint (9) aggregates the dispatch from each technology $k \in \mathbf{K}$ of firm f .

The optimal dispatch problem of firm f

$$\begin{aligned} \pi_f(Y, K) = \max \quad & \sum_{h \in \mathbf{H}} d_h \left((P_h(Y, Q_h(q_{f,h})) + v_h) q_{f,h} \right. \\ & \left. - \sum_{k \in \mathbf{K}} c_k q_{f,k,h} \right) \end{aligned} \quad (5)$$

$$\text{st } q_{f,k,h} = Z_{k,h} K_{f,k} \quad (\mu_{f,k,h}) \quad k \in \mathbf{K}_{\text{nc}}, h \in \mathbf{H} \quad (6)$$

$$q_{f,k,h} \leq K_{f,k} \quad (\lambda_{f,k,h}) \quad k \in \mathbf{K}_{\text{c}}, h \in \mathbf{H} \quad (7)$$

$$\sum_{h \in \mathbf{H}} d_h q_{f,k,h} \leq Q_{f,k}^{\max} \quad (\delta_{f,k}) \quad k \in \mathbf{K}_{\text{c}} \quad (8)$$

$$\sum_{k \in \mathbf{K}} q_{f,k,h} = q_{f,h} \quad (\gamma_{f,h}) \quad h \in \mathbf{H} \quad (9)$$

$$q_{f,k,h} \geq 0 \quad k \in \mathbf{K}_c, h \in \mathbf{H} \quad (10)$$

The variables $\mu_{f,k}$, $\lambda_{f,k,l}$, $\delta_{f,k}$ and $\gamma_{f,h}$ are the Lagrangian multipliers of (6), (7), (8) and (9).

The optimal dispatch problems (5)–(10) of all firms $f \in \mathbf{F}$ are linked through the market's inverse demand function, which captures the impact of demand on the electricity price. The wholesale market is cleared by balancing aggregate supply and demand

$$\sum_{f \in \mathbf{F}} q_{f,h} = Q_h, \quad (\zeta_h) \quad h \in \mathbf{H}. \quad (11)$$

The variable ζ_h is the balancing cost or premium.

We simplify the market structure. We consider a wholesale market for production, but assume that balancing services are provided by a single entity. This entity can cover deficits in aggregate production through rationing. For simplicity, it behaves as a fringe and has neither operational constraints nor involvement with the wholesale market. Profit is determined by a unit premium for contributing to security of supply and a unit cost of rationing. The variable $q_{r,h}$ represents the rationing in segment h and the parameter c_r is the variable cost. Hence, we introduce the rationing problem

$$\pi_r(Y, K) = \max \sum_{h \in \mathbf{H}} d_h(v_h - c_r)q_{r,h} \quad (12)$$

$$\text{st } q_{r,h} \geq 0, \quad h \in \mathbf{H}. \quad (13)$$

In a modern society, electricity is an essential service with low short-term demand elasticity, especially at times of scarcity. To reflect this we assume that part of the electricity demand is price-insensitive. Security of supply is the responsibility of a system operator, ensuring the balance between demand and supply via the system's complementarity constraint introduced in (14). This constraint links the rationing problem and the optimal dispatch problems. It implies that if the aggregated dispatch does not meet inelastic demand Q_h^{\min} in segment h ($\sum_f q_{f,h} < Q_h^{\min}$), then rationing must be provided ($q_{r,h} > 0$)

$$\sum_{f \in \mathbf{F}} q_{f,h} + q_{r,h} \geq Q_h^{\min}, \quad (v_h) \quad h \in \mathbf{H}. \quad (14)$$

The variable v_h is the premium for contributing to security of supply, defined by the complementarity constraint. When $v_h > 0$ then $q_{r,h} = Q_h^{\min} - \sum_f q_{f,h}$ and if $\sum_f q_{f,h} + q_{r,h} > Q_h^{\min}$ then $v_h = 0$. Hence, when the premium is positive, rationing covers deficits in aggregate production, and if inelastic demand is already met, the premium equals zero.

The optimal dispatch problems (5)–(10), the rationing problem (12)–(13), the system constraints (11) and (14) form an equilibrium problem for the entire market, which can be solved as a complementarity problem. The complementarity problem

consists of the Karush-Kuhn-Tucker (KKT) conditions of the optimal dispatch problems (15)-(21), the KKT conditions of the rationing problem (22) and the equilibrium constraints (23)-(24).

The market equilibrium problem

$$d_h c_k + \mu_{f,k,h} + \gamma_{f,h} = 0 \quad f \in \mathbf{F}, k \in \mathbf{K}_{nc}, h \in \mathbf{H} \quad (15)$$

$$0 \leq q_{f,k,h} \perp d_h c_k + \lambda_{f,k,h} + d_h \delta_{f,k} + \gamma_{f,h} \geq 0 \quad f \in \mathbf{F}, k \in \mathbf{K}_c, h \in \mathbf{H} \quad (16)$$

$$d_h \left(\frac{\partial P_h}{\partial q_{f,h}}(Y, Q_h(q_{f,h})) q_{f,h} + P_h(Y, Q_h) + v_h \right) + \gamma_{f,h} = 0 \quad f \in \mathbf{F}, h \in \mathbf{H} \quad (17)$$

$$0 \leq \lambda_{f,k,h} \perp K_{f,k} - q_{f,k,h} \geq 0 \quad f \in \mathbf{F}, k \in \mathbf{K}_c, h \in \mathbf{H} \quad (18)$$

$$q_{f,k,h} = Z_{k,h} K_{f,k}, \mu_{f,k,h} \text{ free} \quad f \in \mathbf{F}, k \in \mathbf{K}_{nc}, h \in \mathbf{H} \quad (19)$$

$$0 \leq \delta_{f,k} \perp Q_{f,k}^{\max} - \sum_{h \in \mathbf{H}} d_h q_{f,k,h} \geq 0 \quad f \in \mathbf{F}, k \in \mathbf{K}_c \quad (20)$$

$$\sum_{k \in \mathbf{K}} q_{f,k,h} = q_{f,h}, \gamma_{f,h} \text{ free} \quad f \in \mathbf{F}, h \in \mathbf{H} \quad (21)$$

$$0 \leq q_{r,h} \perp d_h(c_r - v_h) \geq 0 \quad h \in \mathbf{H} \quad (22)$$

$$\sum_{f \in \mathbf{F}} q_{f,h} = Q_h, \zeta_h \text{ free} \quad h \in \mathbf{H} \quad (23)$$

$$0 \leq v_h \perp \sum_{f \in \mathbf{F}} q_{f,h} + q_{r,h} - Q_h^{\min} \geq 0 \quad h \in \mathbf{H} \quad (24)$$

We introduce the affine inverse demand curve

$$D_h(Q_h) = a_h - b_h Q_h \quad (25)$$

where $a_h > 0$ is the intercept and $b_h > 0$ is the slope of the curve. With an affine and decreasing inverse demand curve, the objective (5) is concave. With the linear constraints, the optimal dispatch problems are in fact convex quadratic programming problems. The rationing problem is likewise convex. In this case, the KKT-conditions are necessary and sufficient for optimality.

As pointed out by [29] and [68], the Cournot-equilibrium with an affine inverse demand function may be cast as a convex quadratic optimization problem for the entire market. In (26)–(34), we list the optimal dispatch problem for the market. The constraints (27)–(30) and (33) equal the constraints (6)–(10). Moreover, (34) is the same as (13). Indeed, it is easy to prove that the KKT conditions of (26)–(34) coincide with the constraints of the complementarity problem in (15)–(24).

The optimal dispatch problem for the market

$$\begin{aligned} \Pi(Y, K) = \max \quad & \sum_{h \in \mathbf{H}} d_h \left(Y \left(a_h Q_h - \frac{1}{2} b_h Q_h^2 \right. \right. \\ & \left. \left. - \frac{1}{2} b_h \sum_{f \in \mathbf{F}: f \neq |\mathbf{F}|} q_{f,h}^2 \right) \right. \\ & \left. - \sum_{f \in \mathbf{F}} \sum_{k \in \mathbf{K}} c_k q_{f,k,h} - c_r q_{r,h} \right) \end{aligned} \quad (26)$$

$$\text{st } q_{f,k,h} = Z_{k,h} K_{f,k} (\mu_{f,k,h}) \quad f \in \mathbf{F}, k \in \mathbf{K}_{\text{nc}}, h \in \mathbf{H} \quad (27)$$

$$q_{f,k,h} \leq K_{f,k} (\lambda_{f,k,h}) \quad f \in \mathbf{F}, k \in \mathbf{K}_{\text{c}}, h \in \mathbf{H} \quad (28)$$

$$\sum_{h \in \mathbf{H}} d_h q_{f,k,h} \leq Q_{f,k}^{\max} (\delta_{f,k}) \quad f \in \mathbf{F}, k \in \mathbf{K}_{\text{c}} \quad (29)$$

$$\sum_{k \in \mathbf{K}} q_{f,k,h} = q_{f,h} (\gamma_{f,h}) \quad f \in \mathbf{F}, h \in \mathbf{H} \quad (30)$$

$$\sum_{f \in \mathbf{F}} q_{f,h} = Q_h (\zeta_h) \quad h \in \mathbf{H} \quad (31)$$

$$\sum_{f \in \mathbf{F}} q_{f,h} + q_{r,h} \geq Q_h^{\min} (v_h) \quad h \in \mathbf{H} \quad (32)$$

$$q_{f,k,h} \geq 0 \quad f \in \mathbf{F}, k \in \mathbf{K}_{\text{c}}, h \in \mathbf{H} \quad (33)$$

$$q_{r,h} \geq 0 \quad f \in \mathbf{F}, h \in \mathbf{H}. \quad (34)$$

The variables $\mu_{f,k}$, $\lambda_{f,k,l}$, $\delta_{f,k}$, $\gamma_{f,h}$, ζ_h and v_h are the Lagrangian multipliers. The objective terms $a_h Q_h - 1/2 b_h Q_h^2$ equal those of a welfare maximization problem, whereas the term $-1/2 b_h \sum_{f \neq |\mathbf{F}|} q_{f,h}^2$ accounts for market power exertion. Each Cournot firm takes the dispatch of its competitors as given and behaves as a monopolist with its residual demand function. Thus, if the market consists of only one Cournot firm, the objective function in (26) equals that of a profit maximizing monopolist.

2.3 Capacity expansion by stochastic control

We proceed with the long-term perspective. The capacity expansion problem of firm f is a stochastic control problem, in which the firm adapts its capacity to the demand throughout the time horizon. Firm f has installed capacity $K_{t,f,k}$ of technology k at year t . The capacity $K_{t,f,k}$ is an entry of the capacity matrices $K_{t,f} = \{K_{t,f,k} : k \in \mathbf{K}\}$ and $K_t = \{K_{t,f,k} : f \in \mathbf{F}, k \in \mathbf{K}\}$. $F_f(Y, K)$ represents the value of all future capacity expansions of firm f . When firm f has no other assets except its generation capacity,

$F_f(Y, K)$ is equivalent to the value of firm f . This value is

$$F_f(Y, K) = \sup_{\{K_{t,f}\}} \mathbb{E}_0 \left[\int_0^\infty \pi_f(Y_t, K_t) e^{-\rho t} dt - \sum_{k \in \mathbf{K}} \int_0^\infty I_k e^{-\rho t} dK_{t,f,k} \right], \quad (35)$$

where \mathbb{E}_0 denotes the expectation conditional on $Y_0 = Y, K_0 = K$ and ρ is the annual discount rate of future cash flows. As should be clear, firm f invests in new capacity to maximize its expected discounted value over an infinite time horizon. The maximization is with respect to $K_{t,f,k}$ for all t and k and subject to the stochastic process $\{K_{t,f} : t \geq 0\}$ being adapted to $\{Y_t : t \geq 0\}$. The first term on the right-hand side of the equality represents expected discounted future profit flows of firm f . The second term on the right-hand side is its expected discounted investment costs from all capacity expansions. The firm can invest in technology k at an investment cost of I_k . This cost includes the expected discounted operations and maintenance costs over the time horizon.

We use dynamic programming to derive the Bellman equation for (35). Investment in technology $k \in \mathbf{K}$ should be undertaken when the marginal value of capacity equals its investment cost, i.e. $\partial F_f / \partial K_{t,f,k} = I_k$. When $\partial F_f / \partial K_{t,f,k} < I_k$ for all $k \in \mathbf{K}$, no investment occurs and the value of the firm F_f satisfies

$$\rho F_f(Y_t, K_t) dt = \pi_f(Y_t, K_t) dt + \mathbb{E}_t[dF_f(Y_t, K_t)], \quad (36)$$

see [24]. We expand the expectation in (36) using Ito's lemma to obtain a partial differential equation. Since its solution is independent of time, we let $Y_t = Y$ and $K_t = K$. To further simplify, we introduce the convenience yield $\delta = \rho - \mu$.

As a result, the value of firm f must satisfy the following Bellman equation:

The optimal control problem for firm f

$$\frac{1}{2} \sigma^2 Y^2 \frac{\partial^2 F_f}{\partial Y^2}(Y, K) + (\rho - \delta) Y \frac{\partial F_f}{\partial Y}(Y, K) - \rho F_f(Y, K) + \pi_f(Y, K) = 0, \quad (37)$$

with boundary conditions

$$\frac{\partial F_f}{\partial K_{f,k}}(Y_{f,k}^*(K), K) = I_k, \quad k \in \mathbf{K}, \quad (38)$$

$$\frac{\partial^2 F_f}{\partial Y \partial K_{f,k}}(Y_{f,k}^*(K), K) = 0, \quad k \in \mathbf{K}, \quad (39)$$

$$F_f(0, K) = 0. \quad (40)$$

where $Y_{f,k}^*(K)$ defines the level of demand that triggers investment for firm f and technology k , given the capacity K . Equation (37) is the Bellman equation and (40) ensures that the value of the firm is zero when the demand shock is zero.

The capacity expansion problems (37)-(40) of all firms $f \in \mathbf{F}$ are linked through the capacities $K = \{K_{f,k} : f \in \mathbf{F}, k \in \mathbf{K}\}$, as these determine the equilibrium of optimal dispatch problems. If each firm takes the investment strategies of the other firms as given, the capacity expansion problems likewise form a Cournot-equilibrium for the entire system.

Our evaluation of the welfare gain from the system's investments is described in Appendix A.

2.4 Myopia and optimal stopping

To the best of our knowledge, the stochastic control problems (37)-(40) cannot be solved analytically. To facilitate an analytical solution, we apply real options theory and approximate the value of capacity expansion by a series of incremental capacity expansion problems, each formulated as an optimal stopping problem. The value of incremental investment is the value of immediate investment less the opportunity cost of deferring investment until it is optimal. For firm f investing marginally in technology k , we denote the opportunity cost by $V_{f,k}(Y, K)$. This cost is

$$V_{f,k}(Y, K) = \inf_{\tau} \mathbb{E}_0 \left[\int_0^{\tau} \frac{\partial \pi_f}{\partial K_{f,k}}(Y_t, K) e^{-\rho t} dt + I_k e^{-\rho \tau} \right], \quad (41)$$

where \mathbb{E}_0 denotes the expectation conditional on $Y_0 = Y$. Moreover, τ represents the timing of the investment and is a stopping time (adapted to the demand). Hence, equation (41) represents firm f 's cost of investing marginally in additional capacity of technology k at the optimal time τ^* , or equivalently, the foregone profit at times $t \leq \tau^*$ and the investment cost at time τ^* . Note that the investment strategy does not involve the capacity level at times $t > \tau^*$.

Following the lines of [24], we assume that

Assumption 1:

$$\frac{\partial F_f}{\partial K_{f,k}}(Y, K) = V_{f,k}(Y, K), \quad k \in \mathbf{K}, \quad (42)$$

i.e. the real options opportunity cost equals the marginal value of capacity expansion. In (41), the capacities are fixed, i.e. $K_t = K$ at all times t . Thus, we assume that investment behavior is myopic. When investment is undertaken, it is assumed to be the last over the time horizon.

To solve the optimal stopping problem, we likewise use dynamic programming and derive the corresponding Bellman equation for (41). Incremental investment in technology $k \in \mathbf{K}$ should be undertaken when $V_{f,k} = I_k$. When $V_{f,k} < I_k$ for all $k \in \mathbf{K}$, no investment occurs and the cost satisfies

$$\rho V_{f,k}(Y_t, K) dt = \pi_f(Y_t, K) dt + \mathbb{E}_t[dV_{f,k}(Y_t, K)]. \quad (43)$$

As above, we expand the expectation in (43) using Ito's lemma and obtain a partial differential equation.

The cost of firm f satisfies:

The optimal stopping problem for firm f

$$\begin{aligned} \frac{1}{2} \sigma^2 Y^2 \frac{\partial^2 V_{f,k}}{\partial Y^2}(Y, K) + (\rho - \delta) Y \frac{\partial V_{f,k}}{\partial Y}(Y, K) - \rho V_{f,k}(Y, K) \\ + \frac{\partial \pi_f}{\partial K_{f,k}}(Y, K) = 0, \quad k \in \mathbf{K} \end{aligned} \quad (44)$$

with boundary conditions

$$V_{f,k}(Y_{f,k}^*, K) = I_k, \quad k \in \mathbf{K} \quad (45)$$

$$\frac{\partial V_{f,k}}{\partial Y}(Y_{f,k}^*, K) = 0, \quad k \in \mathbf{K} \quad (46)$$

$$V_{f,k}(0, K) = 0, \quad k \in \mathbf{K} \quad (47)$$

where $Y_{f,k}^*$ defines the level of demand that triggers incremental investment for firm f and technology k . As above, equation (49) is the Bellman equation and (47) ensures that the opportunity cost is zero when the demand shock is zero. Equations (45) and (46) are the value matching and smooth pasting conditions for an incremental investment in new capacity.

For the optimal stopping problem to have a solution, we further assume that *Assumption 2*:

$$\pi_f(Y, K) = \sum_{k \in \mathbf{K}} \pi_{f,k}(Y, K), \quad \frac{\partial \pi_{f,k}}{\partial K_{f,l}}(Y, K) = 0, \quad k \neq l, \quad (48)$$

i.e. the profit of firm f is additively separable in the technologies $k \in \mathbf{K}$. Note that the optimal dispatch of different technologies is linked through their impact on the electricity price. In spite of this, we use this as an approximation to facilitate a solution.

With this assumption, the optimal stopping problem can be solved separately for firm f and technology k :

The optimal stopping problem for firm f and technology k

$$\begin{aligned} \frac{1}{2} \sigma^2 Y^2 \frac{\partial^2 V_{f,k}}{\partial Y^2}(Y, K) + (\rho - \delta) Y \frac{\partial V_{f,k}}{\partial Y}(Y, K) - \rho V_{f,k}(Y, K) \\ + \frac{\partial \pi_{f,k}}{\partial K_{f,k}}(Y, K) = 0 \end{aligned} \quad (49)$$

with boundary conditions

$$V_{f,k}(Y_{f,k}^*, K) = I_k, \quad (50)$$

$$\frac{\partial V_{f,k}}{\partial Y}(Y_{f,k}^*, K) = 0, \quad (51)$$

$$V_{f,k}(0, K) = 0. \quad (52)$$

2.5 An analytical solution

To obtain an analytical solution to the optimal stopping problem, we make another approximation. In particular, we approximate the instantaneous profit from the optimal dispatch problem by the function

$$\bar{\pi}_{f,k}(Y, K) = \sum_{i=1}^{|\gamma|} \bar{\beta}_{f,k,i}(K) Y^{\gamma_i}, \quad (53)$$

where $\bar{\pi}_{f,k}$ is obtained by a regression for firm f and technology k of the instantaneous profit on Y . The left-hand side of the equality shows firm f 's profit flow from technology k . The regression coefficients, $\bar{\beta}_{f,k,i}(K)$, on the right-hand side describe how changes in the capacity affect the instantaneous profit flow of firm f and technology k . If firm f installs new capacity, it has a positive impact on its instantaneous profit, whereas additional installations of capacity of all other firms reduces the electricity price and thus the instantaneous profit of firm f , regardless of the technology k . Both effects are captured in the regression coefficients $\bar{\beta}_{f,k,i}(K)$. The coefficients can therefore be positive or negative. The parameter γ is a positive vector of size $|\gamma|$ used to describe changes in $\bar{\pi}_{f,k}(Y, K)$ with respect to Y .

The differential equation of firm f and technology k , (49), has the homogeneous solution $V_{f,k}^H(Y, K) = A_{f,k}(K)Y^{\alpha_1}$. For this to be a solution, α_1 is the positive root of the so-called quadratic equation, i.e.

$$\alpha_1 = \left(\frac{1}{2} - \frac{\mu}{\sigma^2} \right) + \sqrt{\left(\frac{1}{2} - \frac{\mu}{\sigma^2} \right)^2 + \frac{2\rho}{\sigma^2}}. \quad (54)$$

The particular solution of (49) is the value of immediate investment, namely, the firm's profit from marginal investment:

$$V_{f,k}^P(Y, K) = \mathbb{E}_0 \left[\int_0^\infty \frac{\partial \bar{\pi}_{f,k}}{\partial K_{f,k}}(Y_t, K) e^{-\rho t} dt \right] = \sum_{i=1}^{|\gamma|} \beta_{f,k,i}(K) Y^{\gamma_i}, \quad (55)$$

where the coefficients $\beta_{f,k,i}$ are given by

$$\begin{aligned} \beta_{f,k,i}(K) &= \frac{\partial \bar{\beta}_{f,k,i}}{\partial K_{f,k}}(K) \mathbb{E}_0 \left[\int_0^\infty Y_t^{\gamma_i} e^{-\rho t} dt \right] = \frac{\partial \bar{\beta}_{f,k,i}}{\partial K_{f,k}}(K) \int_0^\infty \mathbb{E}_0[Y_t^{\gamma_i}] e^{-\rho t} dt \\ &= \frac{\partial \bar{\beta}_{f,k,i}}{\partial K_{f,k}}(K) \frac{1}{\rho - \mu \gamma_i - \frac{1}{2} \sigma^2 \gamma_i (\gamma_i - 1)}, \end{aligned} \quad (56)$$

using that

$$dY_t^{\gamma_i} = (\mu \gamma_i + \frac{1}{2} \sigma^2 \gamma_i (\gamma_i - 1)) Y_t^{\gamma_i} dt + \gamma_i \sigma Y_t^{\gamma_i} dz_t.$$

The solution of the Bellman equation is the sum of the homogeneous and the particular solution, $V_{f,k}(Y_t, K_t) = V_{f,k}^H(Y_t, K_t) + V_{f,k}^P(Y_t, K_t)$. Consequently, firm f 's value of investing in technology k is given by

$$V_{f,k}(Y, K) = A_{f,k}(K)Y^{\alpha_1} + \sum_{i=1}^{|\gamma|} \beta_{f,k,i}(K)Y^{\gamma_i}. \quad (57)$$

By applying the value matching and smooth pasting conditions (50)–(51), we obtain the investment trigger equation of firm f and technology k :

$$\sum_{i=1}^{|\gamma|} (Y_{f,k}^*)^{\gamma_i} \left(\frac{\alpha_1 - \gamma_i}{\alpha_1} \right) \beta_{f,k,i}(K) = I_k. \quad (58)$$

In (58), $Y_{f,k}^*$ is the optimal investment trigger of firm f and technology k . When $Y < Y_{f,k}^*$ for all $k \in \mathbf{K}$, firm f defers investment. When $Y = Y_{f,k}^*$, firm f invests marginally in additional capacity of production technology $k \in \mathbf{K}$. As in [19], we impose that $0 < \gamma_i < \alpha_1$ for all i to obtain a unique investment trigger.

The trigger equations (58) of all firms $f \in \mathbf{F}$ and technologies $k \in \mathbf{K}$ are linked through the capacities $K = \{K_{f,k} : f \in \mathbf{F}, k \in \mathbf{K}\}$. We approximate the capacity expansion Cournot-equilibrium by solving these equations simultaneously.

2.6 Numerical solution procedure

Based on the real options formulation of the incremental capacity expansion problems and the corresponding investment triggers, we propose a partly analytical, partly numerical heuristic.

The heuristic is divided into an inner and an outer loop. In the former, the optimal stopping problems are solved to find investment triggers, given the current capacities. In the latter, we approximate the expected values of the capacity expansions for all firms, i.e. the values (35), and for society, see Appendix A. In the heuristic, we no longer work in continuous time and with infinite time horizon. The time horizon is finite and discretized into years.

The inner loop considers a grid of initial values for the demand shock. For each grid point, $Y = Y_0$, we use Monte Carlo simulation to generate a number of paths, referred to as scenarios, $\omega = 1, \dots, \Omega$, of yearly demand shock realizations throughout the time horizon $t = 1, \dots, T$. We fix the installed capacity due to myopia. For each year t and each scenario ω , the market equilibrium problem considers the demand $Y_{t,\omega}$ (with $Y_{0,\omega} = Y_0$) and capacity $K = K_0$ and determines the dispatch of the firms in all time segments of the year. We use the Lagrangian multipliers $\mu_{f,k,h}(Y_{t,\omega}, K)$ and $\lambda_{f,k,h}(Y_{t,\omega}, K)$ of the capacity constraints (6) and (7) as proxies for the profits accruing during a time segment upon installing a unit of additional capacity. The multipliers are used to compute the expected discounted future value of an additional unit of capacity

$$V_{f,k}^P(Y, K) = \frac{1}{\Omega} \sum_{\omega=1}^{\Omega} \sum_{t=1}^T \sum_{h \in \mathbf{H}} d_h \mu_{f,k,h}(Y_{t,\omega}, K) e^{-\rho t}, \quad k \in \mathbf{K}_{\text{nc}} \quad (59)$$

$$V_{f,k}^P(Y, K) = \frac{1}{\Omega} \sum_{\omega=1}^{\Omega} \sum_{t=1}^T \sum_{h \in \mathbf{H}} d_h \lambda_{f,k,h}(Y_{t,\omega}, K) e^{-\rho t}, \quad k \in \mathbf{K}_{\text{c}} \quad (60)$$

These marginal values are used for the regression on the initial demand shock. The regression (53) is replaced by a non-negative least square regression of the value of incremental investment

$$V_{f,k}^P(Y, K) = \sum_{i=1}^{|\gamma|} \beta_{f,k,i}(K) Y^{\gamma_i}, \quad k \in \mathbf{K} \quad (61)$$

with

$$\beta_{f,k,i}(K) \geq 0, \quad k \in \mathbf{K}, i = 1, \dots, |\gamma|, \quad (62)$$

Table 2: Historical electricity load in Germany, in TWh.

| Year | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| Load | 559.1 | 555.9 | 557.2 | 526.9 | 547.4 | 544.3 | 539.9 | 530.6 | 529.4 | 520.6 |

where (62) is introduced to ensure a unique solution to (58). The regression coefficients serve as input to the trigger equations that determine investment thresholds.

The outer loop likewise uses Monte Carlo simulation to generate scenarios $\omega = 1, \dots, \Omega$, of yearly demand shock realizations throughout the time horizon $s = 1, \dots, S$. For each year, s , and each scenario, ω , we run the inner loop with initial demand shock $Y_0 = Y_{s,\omega}$ and determine the investment thresholds of firm f and technology k , $Y_{s,f,k}^*$. If the demand shock at time s , exceeds the investment trigger, firm f invests marginally in technology k . If the trigger is reached for several technologies, firm f invests in the technology with the lower threshold. Upon investment, the installed capacity K_s is updated. We run the inner loop with $K_0 = K_s$ and find investment triggers until it is no longer optimal to invest. Then, we increment s by one. The procedure is repeated until the end of the time horizon. Finally, we determine the expected value of all capacity expansions of a firm by computing the average value of investment over all scenarios.

3 Model parameters

This section describes the methods for determining model parameters from market data. We consider a case study of the German power market and use real data to obtain supply and demand parameters and the technology mix.

3.1 Annual trend and volatility in long-term electricity demand

In the German power market, future energy consumption must decline. This follows from the target in Energiewende, cf. [49], of decreasing greenhouse gas emissions in Germany by 85–90 % by 2050. [39] argues that the German energy consumption may be reduced by 4.35 % from 2015 to 2030, which constitutes a decline of 0.29 % per year. Thus, we let the annual trend of the long-term electricity demand in (1) be $\mu = -0.29\%$.

The annual volatility is estimated from yearly power consumption data from 2006 to 2015, obtained from [12] and shown in Table 2. The annual volatility for the years $t = 1, \dots, T$ is computed by the formula

$$\sigma = \sqrt{\frac{1}{T-1} \sum_{t=1}^T \left((\ln Q_t - \ln Q_{t-1}) - \frac{1}{T} \sum_{t=1}^T (\ln Q_t - \ln Q_{t-1}) \right)^2} \quad (63)$$

where Q_t is the annual dispatch of year t . This formula is valid for log-normal distributions, including the geometric Brownian motion. The resulting volatility in long-term electricity demand is $\sigma = 2.3\%$.

Table 3: Parameters of the inverse demand function for time segments $h \in \mathbf{H}$.

| Time segment h | 1 | 2 | 3 | 4 | 5 |
|------------------|---------|---------|---------|---------|---------|
| a_h | 362 | 211 | 173 | 159 | 116 |
| b_h | -0.0040 | -0.0023 | -0.0023 | -0.0028 | -0.0026 |

3.2 Inverse demand function

We obtain the parameters of the inverse demand function in each time segment by a linear regression of hourly load data from [12] on hourly electricity prices for the German and Austrian wholesale market from [47]. The resulting parameters of the inverse demand functions are shown in Table 3.

3.3 Required rate of return

We deal with price risk when estimating the trend and volatility of long-term electricity demand, and we assume that no other risk factors are involved. In reality, risk factors such as technical and political risk may influence the required rate of return. Technical risk involves replacements of components that do not operate as efficiently as expected, whereas political risk relates to government changes of carbon taxes and subsidies. Here, we assume that technical and political risks are minor. Hence, we use a discount rate of 4 % as suggested by [10].

3.4 Load and renewable production segments

When dividing a year into time segments we aim to represent short-term variability in load and production from wind and solar power along with the correlation between these parameters. However, since hourly time segments would make our approach computationally intractable, we use temporal aggregation. Our segmentation procedure is based on a multi-dimensional duration curve approach as presented in [4]. Starting from historical hourly time-series for load, the procedure first constructs a duration curve and a step-function approximation to this curve. To account for correlation, historical hourly wind and solar power production data is mapped to the segments of the approximate load duration curve. Duration curves and step-function approximations are likewise constructed for these parameters. The combination of step-functions serve as input to the market equilibrium problem.

The data series used in the segmentation procedure are hourly normalized load and production profiles from 2010 to 2014. Hourly electric load is provided by [12], and hourly solar and wind power production profiles are collected from the Renewables.ninja project, see [52] and [63]. The load duration curve is divided into 5 load segments, and the solar and wind production duration curve into 4 segments each. In total, we thereby use $|\mathbf{H}| = 5 \times 4 \times 4 = 80$ segments to represent a full year.

3.5 Technology data

In Appendix B and C we present and discuss the cost and capacity data. We let the cost of rationing be 10 000 €/MWh, which is within the range of [21]. The renewable energy subsidy system of Germany is rapidly changing and governmental auctions for new renewable projects has been won without subsidies [56]. Thus, we disregard subsidies.

3.6 Model implementation

We have implemented our model in Matlab 2016a [45], using five computation nodes and the following hardware: Lenovo NeXtScale, 2 x Intel E5-2643v3, 3.4 GHz, 512 Gb RAM. The optimal dispatch problem for the market is solved using the Gurobi 7.0.2 quadratic optimization solver [22].

The optimal stopping problem is solved on a grid for initial demand with 7 values and intervals of 0.1, as shown in Table 18. At each grid point, we simulate over T years, where $T = 50$ in our illustrative example and $T = 40$ in our German case study. The value of investment is evaluated using $\Omega = 500$ simulations. This is less than the ideal number of simulation but serves to limit the computation time that exceeds 24 hours in the German case study. The time horizon is $S = 10$ years in the illustrative example and $S = 23$ in the Germany case study.

4 Illustrative example

We examine a power market with two Cournot firms and a competitive fringe over an analysis period of 10 years. All firms have access to wind, solar, coal and combined-cycle gas turbine (CCGT) power plants. Input data for the initial installed capacities, costs, discount rate, and parameter estimates for the geometric Brownian motion are presented in Appendix B. We further use the parameter estimates in Section 3. For simplicity, we disregard the maximal production constraint, (8), and the security of supply constraint, (14).

Fig. 1a illustrates the development of the technology mix in the power market. Almost all new investments occur during the first year of the analysis period, indicating that the initial capacity is insufficient. The trend in demand of only 1% makes capacity investments limited during the remainder of the period. We note that 92 % of the investments during the analysis period are in solar and wind power plants. Investments in such power plants are attractive despite their non-controllable dispatch, since they have no marginal costs. Investments in CCGT and coal-fired generators are present, but to a minor extent. Coal-fired power plants are base load plants with low marginal costs and high investment cost, while CCTG power plants have opposite cost characteristics and are peak load plants. Due to the high marginal cost of CCGT plants, their contribution margin is considerably smaller than that of coal-fired plants. Consequently, the marginal value of additional capacity is low for CCGT compared coal-fired power plants. However, the operation of CCGT power plants is profitable

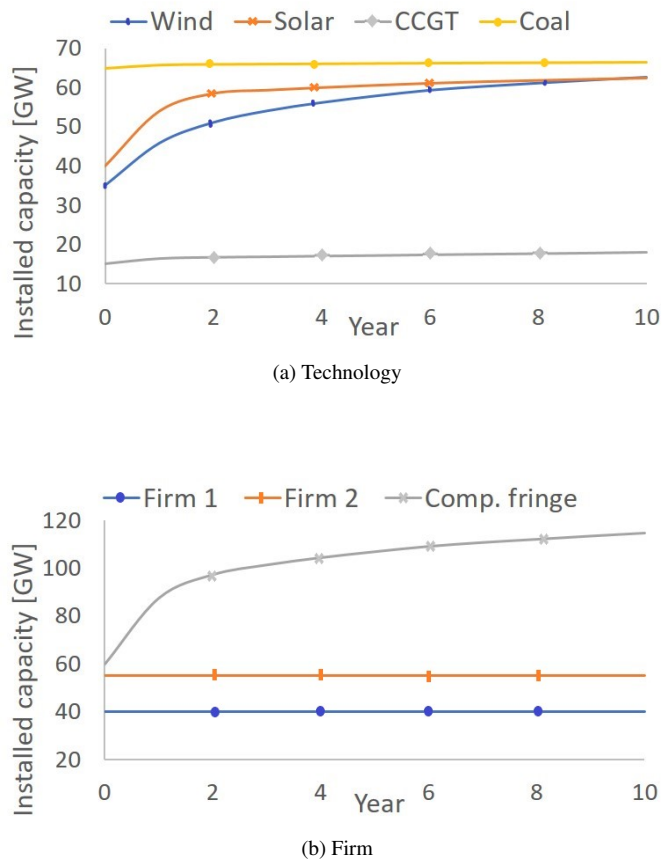


Fig. 1: The development of installed capacity by technology and firm.

in the time segments with high load net of non-controllable production and CCGT plays a key role in suppressing prices in these segments. If their durations are sufficiently short, the incentive to invest in peak load capacity is low. Then, periods of deficits in aggregate production, i.e. power shortage, can be observed. Nevertheless, we note that the durations are sufficient to maintain the profitability of the CCGT plants in this example.

In Fig. 1b, we observe that the competitive fringe increases its market share of capacity over the next 10 years. In contrast to traditional oligopolistic behavior, we find that the Cournot firms do not defend their market shares. In fact, they are better off with smaller market shares and higher prices. If the Cournot firms exercise a high level of market power, the electricity price increases until it is advantageous for new firms to enter the market and for existing price-taking firms to expand their

capacity and generate additional electricity. The competitive fringe is such a price-taker. Increasing its dispatch does not influence the price and its marginal value of additional capacity exceeds that of a Cournot firm. By accounting for market power, we therefore observe that strategic firms do not increase their market shares over time but hold back investment until prices are sufficiently high for price-taking firms to expand capacity.

5 Case study of the German power market

Through the epochal transformation, Energiewende, Germany aims to revamp their economy by reducing carbon emissions with 80–95% by 2050, compared to the levels of 1990, see [27]. To meet this ambitious emission target, new renewable capacity will have to substitute the conventional power plants of today. We seek to determine the technologies and capacity levels that competitive firms will find attractive by applying our capacity expansion model to the German power market, using an analysis period from 2017 to 2040. The German power sector is dominated by four large firms: RWE, Uniper, Vattenfall and EnBW, with a total share of almost 60 % of the generated electricity in 2012, cf. [55]. We model these firms as Cournot firms, in the same spirit as [31]. The rest of the power-producing firms are considered price-takers. Input data is presented in Section 3 and Appendix C.

Although our model does not account for time-varying costs, in our simulations, we let costs change over the analysis period. Investment costs of solar and wind power are expected to decline over the next decades. In contrast, carbon prices, and thus, the marginal costs of conventional power plants are likely to rise over the same period. For technologies with decreasing (resp. increasing) costs, the true value of waiting is therefore higher (resp. lower) than the model predicts. An underestimated (resp. overestimated) value of waiting results in earlier (resp. later) investments than optimal. In addition, our simulations assume finite lifetimes of the power plants, and hence, the marginal value of additional capacity is lower than for a model with an infinite lifetime. These modifications to the modeling framework are introduced to closer reflect reality.

5.1 Base case

Our base case assumes Cournot competition and no regulation such as capacity payments.

The use of real options analysis allows us to obtain technology-specific thresholds, above which demand is sufficiently high to trigger investment. Table 4 provides the trigger levels for demand in the beginning of the analysis period, i.e. 2017. The numbers are sorted by firm and technology and normalized by the initial demand shock. Hence, a trigger level indicates the required percentual increase in demand to incentivize investment. The first column of numbers assumes Cournot competition and no regulation. It can be observed that a doubling of current demand more or less triggers renewable investment, whereas base load and peak load generation require over 50 times current demand on average. Hence, no investments occur in 2017.

Table 4: Investment triggers of 2017 sorted by firm and technology and under Cournot competition, perfect competition and regulation, respectively. Normalized by the initial demand shock and truncated to 100.

| Firm | Technology | Cournot | Perfect | Regulated |
|------------|------------|---------|---------|-----------|
| RWE | Wind | 2.39 | 2.39 | 2.39 |
| | Solar | 2.60 | 2.60 | 2.60 |
| | Biomass | 6.48 | 6.47 | 6.47 |
| | Hydropower | 100 | 100 | 100 |
| | Nuclear | 100 | 100 | 100 |
| | Hard Coal | 100 | 100 | 100 |
| | Brown Coal | 100 | 100 | 100 |
| | CCGT | 100 | 100 | 100 |
| | OCGT | 100 | 100 | 100 |
| Uniper | Wind | 1.85 | 1.85 | 1.85 |
| | Solar | 2.02 | 2.02 | 2.02 |
| | Biomass | 3.07 | 3.07 | 3.08 |
| | Hydropower | 99.0 | 100 | 100 |
| | Nuclear | 100 | 100 | 100 |
| | Hard Coal | 18.4 | 18.4 | 24.3 |
| | Brown Coal | 4.57 | 4.73 | 4.92 |
| | CCGT | 100 | 100 | 100 |
| | OCGT | 100 | 100 | 100 |
| Vattenfall | Wind | 1.83 | 1.82 | 1.83 |
| | Solar | 2.00 | 2.00 | 2.00 |
| | Biomass | 2.95 | 2.94 | 2.95 |
| | Hydropower | 98.0 | 98.0 | 97.1 |
| | Nuclear | 100 | 100 | 100 |
| | Hard Coal | 3.56 | 4.51 | 3.66 |
| | Brown Coal | 3.67 | 3.74 | 3.84 |
| | CCGT | 100 | 100 | 100 |
| | OCGT | 100 | 100 | 100 |
| EnBW | Wind | 2.000 | 1.998 | 2.000 |
| | Solar | 2.188 | 2.187 | 2.188 |
| | Biomass | 3.74 | 3.73 | 3.74 |
| | Hydropower | 76.6 | 72.6 | 82.4 |
| | Nuclear | 100 | 100 | 100 |
| | Hard Coal | 100 | 100 | 100 |
| | Brown Coal | 5.75 | 6.07 | 6.49 |
| | CCGT | 100 | 100 | 100 |
| | OCGT | 100 | 100 | 100 |
| Fringe | Wind | 1.623 | 1.621 | 1.625 |
| | Solar | 1.786 | 1.784 | 1.788 |
| | Biomass | 1.990 | 1.999 | 2.01 |
| | Hydropower | 100 | 100 | 100 |
| | Nuclear | 100 | 100 | 100 |
| | Hard Coal | 2.20 | 2.22 | 2.26 |
| | Brown Coal | 2.11 | 2.14 | 2.15 |
| | CCGT | 11.2 | 12.2 | 10.1 |
| | OCGT | 100 | 100 | 100 |

Installed capacities are consistent with the thresholds. Fig. 2a illustrates the installed capacity of different generation technologies. No investments occur before 2022 despite power plants reaching the end of their lifetime, indicating that Germany has a sufficient level of installed capacity today.

After 2030, investments in solar and wind power plants are boosted despite their non-controllable dispatch. This may be explained by their reduction in investment costs and a rise in the carbon price, making renewables relatively more profitable than conventional power plants. It may be argued, however, that these investments are overestimated because the value of waiting for a lower investment cost or a higher carbon price is not fully captured in our model. Nevertheless, we do not experience investments in solar and wind power before 2030.

No capacity is installed in the conventional base load technologies, i.e. hard coal, brown coal and nuclear. Nuclear power plants are actively phased out according to German policy, see [27], and the increased marginal cost as a result of the rising carbon price makes the other technologies uncompetitive compared to renewables and open-cycle gas turbine (OCGT) plants.

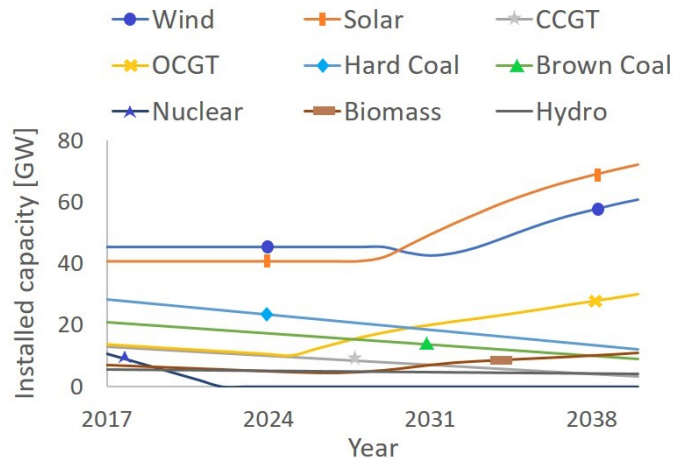
With a reduction in the capacity of conventional power plants but a boost in renewable capacity over the analysis period, total installed capacity increases. The reason is that solar and wind power plants have lower normalized generation than base load power plants.

The installed capacity in base load power plants and renewables is sufficiently high to avoid rationing in most of the time segments before 2030. As investment in renewable capacity increases during the analysis period, however, the need for peak load investment rises. OCGT plants have low investment costs and high marginal costs and are therefore peak load plants, suitable for covering short periods of deficits in production. In periods with high load and modest renewable generation, they have a positive contribution margin, which makes them attractive to invest in.

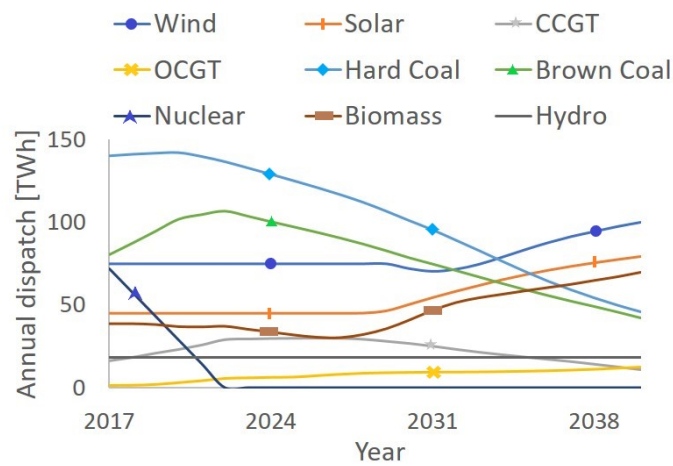
The dispatch is presented in Fig. 2b. Given the capacity mix in Fig. 2a, generation from peak load plants become necessary to avoid rationing as time passes. Such controllable capacity covers demand net of renewable generation and conventional base load but have a high marginal cost. This shifts the market equilibrium to one with a lower total dispatch at a higher price. The slightly negative trend in demand may likewise contribute to a decline in the total dispatch.

We notice that the dispatch of wind and solar increases in line with investments and that more power is generated by biomass as time passes. This is not surprising, as solar and wind power have no marginal costs, and except for these, biomass has the lowest marginal cost after 2030. Hydropower plants likewise have no marginal cost, but their dispatch is constrained and their investment costs are high. In spite of a decline in investment capacity, we also observe that the coal-fired power plants maintain a high normalized generation, i.e. they produce a considerable share of the total dispatch. This happens because the coal-fired power plants have lower marginal costs than gas-fired power plants.

The covering of demand net of renewable and coal-fired production by the gas-fired power plants is first with CCGT and second with OCGT plants. CCGT plants have higher investment cost and lower marginal cost than OCGT plants and therefore cover medium load. OCGT plants, on the other hand, operate as a strategic reserve



(a) Installed capacity



(b) Annual dispatch

Fig. 2: The development of installed capacity and annual dispatch of the generation technologies, 2017–2040.

in the market and only generate electricity when all other power plants are already in use.

Finally, we find consistency between our results and the policy targets in Energiewende. Our approach indicates that 70 % of the total dispatch is generated by renewables by 2040 compared to the target 67%, see [27].

Fig. 3 presents electricity prices for selected time segments with varying load and renewable generation. We confirm that an increased share of renewables leads to lower prices when the renewable normalized production is high, but higher prices otherwise. Additionally, the increase of non-controllable wind and solar power plants results in higher price fluctuations between time segments. The negative prices in the time segment with low demand and high renewable production is due to the assumption that wind and solar power production have to be dispatched.

5.2 Perfect competition

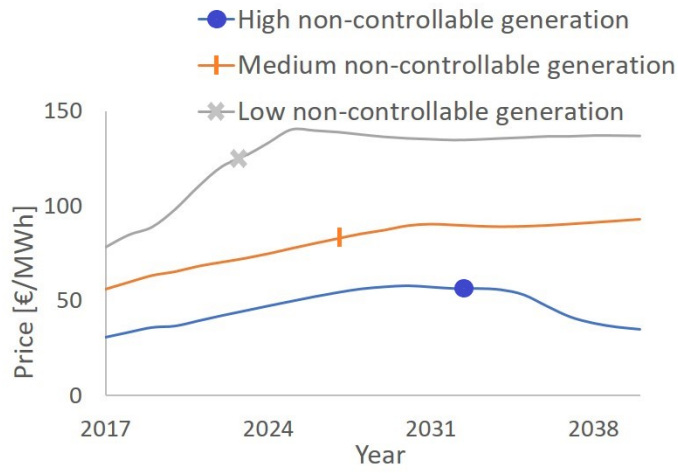
We compare investment behavior in the imperfectly competitive market to the case in which investment and dispatch are determined by a benevolent central planner, or equivalently, a perfectly competitive market. In contrast to firms that are able to exercise market power, the central planner aims to maximize the total welfare gain from capacity investments. The central planner gains a higher consumer surplus than the imperfectly competitive market at the expense of a lower producer surplus.

The second column of numbers in Table 4 provides investment thresholds under perfect competition. Generally, the trigger levels are almost the same as those with imperfect competition. The average demand level required to incentivize investments is slightly lower under the central planner, reflecting that with imperfect competition Cournot firms withhold investment to maintain a high power price and producer surplus. In particular, the trigger levels are lower for renewable and gas-fired plants. However, they are higher for coal-fired plants, meaning that the central planner is more hesitant to invest in such capacity. A plausible reason is that Cournot firms have more incentive to invest in controllable capacity, as they can use this to exercise market power. This is not possible with the non-controllable renewable capacity.

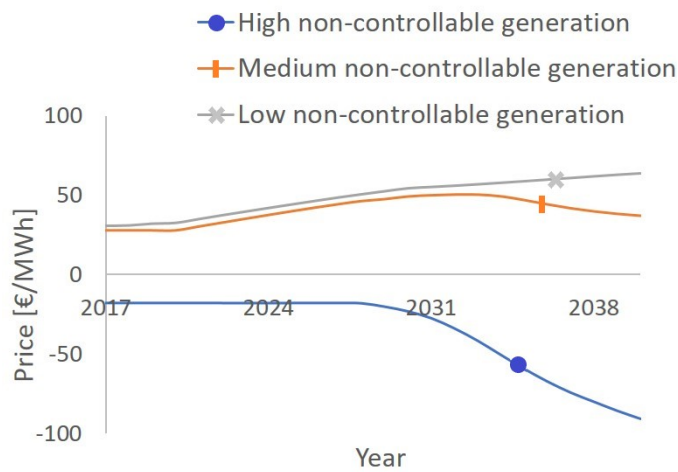
We proceed to compare power prices. In Fig. 4, we observe that for the first 13 years of the analysis period, the average power price is lower under the central planner than in the imperfectly competitive market. With imperfect competition, firms in possession of market power control a high share of the installed controllable capacity. They exhibit market power by withholding dispatch to maintain a high power price and thereby producer surplus, especially during peak periods. After 2030, a significant part of the base load capacity with low marginal cost has been phased out and the Cournot firms have lost market power. As a result, the average price in the imperfectly competitive market converges to the average price under the central planner.

5.3 Capacity payments

In the optimal dispatch problem for the market (26)–(34), we included the problem of an entity that governs rationing and carries its cost. Although firms do not carry the



(a) High demand



(b) Low demand

Fig. 3: Electricity prices in selected time segments when non-controllable dispatch is high, medium and low, respectively, 2017–2040

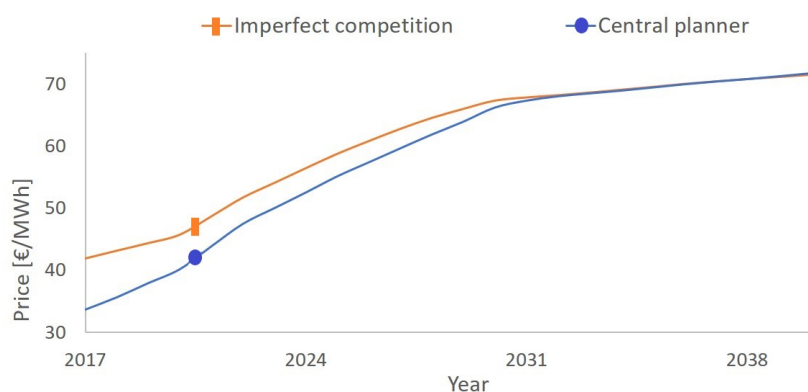


Fig. 4: Average power prices in the imperfectly competitive market and the market governed by a central planner, 2017–2040.

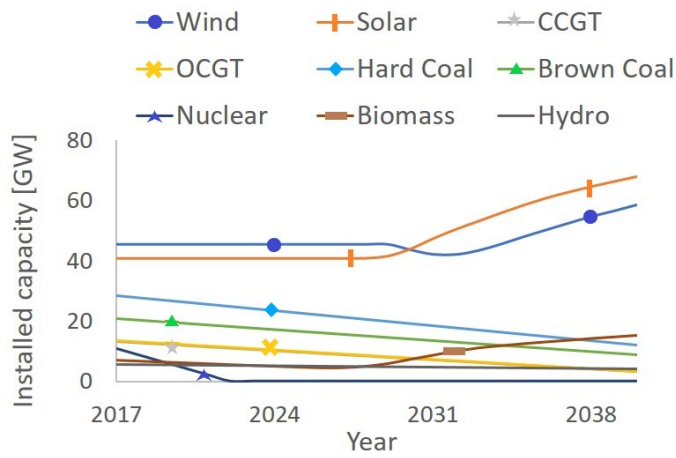
cost of rationing, this affects their marginal value of additional capacity through the system constraint (14). For comparison, we consider a market that does not include the rationing problem.

Fig. 5 presents investment and dispatch of gas-fired power plants. We observe a significant reduction in the installed capacity and dispatch of gas-fired power plants. Not surprisingly, we notice a significant level of rationing within 2040.

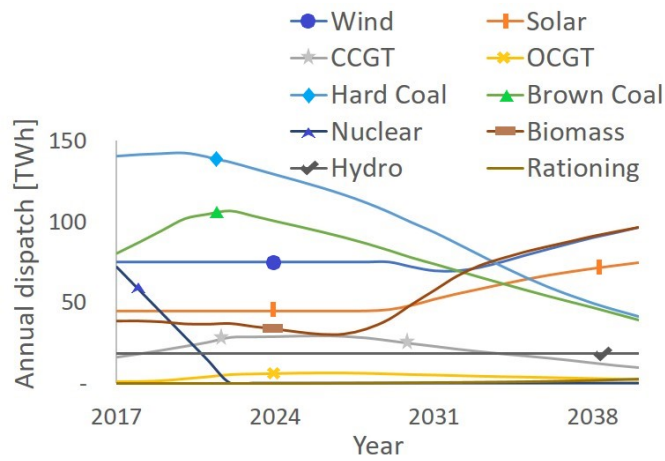
To avoid rationing, the regulator must incentivize investments in peak load capacity, e.g. by introducing capacity payments. We argue for a capacity payment of 31 000 €/MW in Appendix D. A higher level makes peak load plants profitable even with little generation, and a lower level leads to less peak load investments than optimal for the system, as shown in Tables 19 and 20 of Appendix D. It is reasonable for the regulator to make capacity payments to gas-fired power plants, as these have the lowest emissions and can easily ramp up and down.

Fig. 6a shows installed capacities when both OCGT and CCGT power plants receive capacity payments. We notice excessive investments in CCGT plants at the expense of renewables. The renewable dispatch is 42% in 2040. With capacity payments for OCGT only, as illustrated in Fig. 6b, we find a capacity mix similar to the one presented in Fig. 2a. Despite the introduction of capacity payments, however, we do not manage to replicate the investment behavior with minimization of rationing. The renewable dispatch is 67% in 2040 but rationing is still present. Nevertheless, we argue that introducing capacity payments of 31 000 €/MW, i.e. 7.2% of the investments cost of OCGT power plants, produces results closest to the base case.

The third column of numbers in Table 4 provides investment thresholds with capacity payments for OCGT only. As desired, the investment triggers are similar to those of Cournot competition including the rationing problem, i.e. the first column of the table. However, the capacity payments slightly overcompensate for excluding minimization of rationing, with lower thresholds for investments in OCGT plants of the fringe but higher thresholds for the coal-fired plants of especially the Cournot firms.

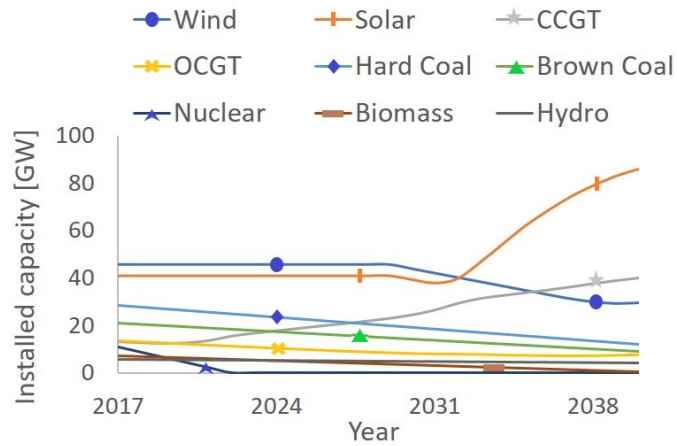


(a) Installed capacity

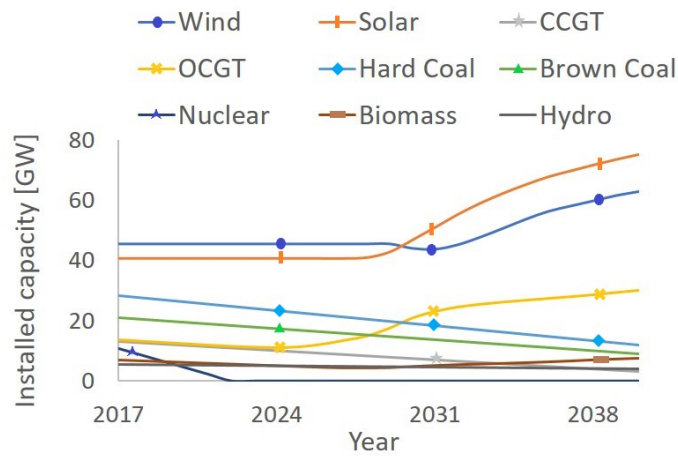


(b) Annual dispatch

Fig. 5: The development of installed capacity and annual dispatch in the market without minimization of rationing, 2017–2040.



(a) OCGT and CCGT



(b) OCGT

Fig. 6: Installed capacity with capacity payments of 31 000 €/MW, 2017–2040

6 Concluding remarks

This paper analyses how firms in the electricity market, with different levels of market power, invest in new capacity. We use a real options approach and include several features such as heterogeneous technologies, an endogenous electricity price, time-varying short-term demand and renewable supply and long-term demand uncertainty.

The aim is to provide regulators and policymakers with a better understanding of the investment behavior in imperfectly competitive power markets with an increasing penetration of renewable production.

In an illustrative example, we show that large firms use their market power to maintain high prices instead of defending their market shares. In fact, increasing their dispatch reduces the electricity price, and thus, their incentive to invest in new capacity is small compared to price-taking firms. If excessive market power is exercised, new firms will enter the market and the intensity of competition increases.

We further apply our framework to the German electricity market. We observe that a high renewable penetration results in large price fluctuations and rationing. However, investments in peak load capacity provide a controllable dispatch that reduces price spikes and may serve to avoid deficits in production. We demonstrate that without explicit minimization of rationing, capacity payments are beneficial to avoid high deficits in production but that the design of the capacity payment mechanism significantly affects the capacity mix. We argue that capacity payments to technologies with low investment costs and high marginal costs have benefits that offset the disadvantages of a high share of renewables.

Although our framework shows that capacity payments to peak load plants help to meet the targets in Energiewende, it should be remarked that several characteristics of the German power market are left out of the analysis, e.g. offshore wind power plants, batteries, cross-border interconnections, and carbon capture and storage. These characteristics could be incorporated into our model. Extensions of our framework are possible in several other directions. For instance, the equilibrium model may be extended to include a power grid with several nodes, such as to use our framework for optimal grid investments. With regard to modeling, we may extend the optimal stopping problem to allow for time-dependent costs. Finally, it would be highly interesting to quantify the inaccuracy of assuming myopia.

A Welfare gain

The welfare gain equals the expected discounted social welfare from the capacity expansions over an infinite time horizon, i.e.

$$\mathbb{E}_0 \left[\int_0^\infty \psi(Y_t, K_t) e^{-\rho t} dt - \sum_{f \in \mathbf{F}} \sum_{k \in \mathbf{K}} \int_0^\infty I_k e^{-\rho t} dK_{t,f,k} \right], \quad (64)$$

where

$$\psi(Y, K) = \sum_{h \in \mathbf{H}} d_h \left(\int_0^{Q_h} P_h(Y_t, Q) dQ - \sum_{f \in \mathbf{F}} \sum_{k \in \mathbf{K}} c_k q_{f,k,h} - c_r q_{r,h} \right)$$

is the instantaneous social welfare, i.e. the sum of producer profits and consumer surplus, and $\{K_{t,f} : t \geq 0\}$ is the (approximate) optimal solution to (35).

B Input parameters of the illustrative example

Table 5: Cost data

| | Wind | Solar | CCGT | Coal |
|-----------------------------|---------|---------|---------|-----------|
| Fuel cost [€/MWh] | | | 41.20 | 11.61 |
| Emission cost [€/MWh] | | | 7.62 | 21.71 |
| Marginal cost, c [€/MWh] | 0 | 0 | 48.83 | 33.32 |
| O & M. cost, OMC [€/MWy] | 38 000 | 17 000 | 18 000 | 42 000 |
| Investment cost, I [€/MW] | 760 000 | 650 000 | 730 000 | 2 380 000 |

Operation and maintenance costs and investment costs are extracted from [59]. For solar and wind power, we use data from 2030. Fuel and emission costs are extracted from Table 12. [59] summarizes cost data from several sources. The validation of data from [59] is outside the scope of this paper.

Table 6: Initial installed capacity

| | Wind | Solar | CCGT | Coal |
|-------------------------|--------|--------|--------|--------|
| Firm 1 [MW] | 0 | 0 | 0 | 40 000 |
| Firm 2 [MW] | 15 000 | 20 000 | 10 000 | 10 000 |
| Competitive fringe [MW] | 20 000 | 20 000 | 5 000 | 15 000 |

Table 7: Parameters for demand shock process, discount rate and α_1

| Y_0 | μ | σ | ρ | α_1 | S | T |
|-------|-------|----------|--------|------------|-----|-----|
| 1 | 0.01 | 0.03 | 0.04 | 3.58 | 10 | 50 |

Table 8: Y_0^{grid} and γ

| | |
|---------------------|--|
| Y_0^{grid} | $Y_s - 0.3, Y_s - 0.2, \dots, Y_s + 0.3$ |
| γ | $0.27, 0.54, 0.81, \dots, 3.51$ |

C Input data case study Germany

All costs are given for the years 2017, 2020, 2030 and 2040. We use linear interpolation to determined costs between these years. After 2040, we assume all costs to be fixed at 2040 levels. Validation of data is outside the scope of this paper.

Table 9: Investment costs [€/kW]

| Technology | 2017 | 2020 | 2030 | 2040 |
|------------|-------|-------|-------|-------|
| Wind | 980 | 860 | 760 | 660 |
| Solar | 980 | 800 | 650 | 500 |
| Biomass | 2 350 | 2 400 | 2 300 | 2 220 |
| Hydro | 1 600 | 1 600 | 1 570 | 1 570 |
| Nuclear | 6 480 | 6 480 | 6480 | 6480 |
| Hard coal | 1 940 | 1 940 | 1 940 | 1940 |
| Brown coal | 2 380 | 2 380 | 2 380 | 2 380 |
| CCGT | 430 | 430 | 430 | 430 |
| CCGT | 730 | 730 | 730 | 730 |

Investment costs are extracted from [59]. We assume all wind power plants to be onshore and assume that all hydropower plants are impoundment facilities. There are few unused reservoirs in Germany today. Hence, we use cost data for refurbishing existing hydropower plants with reservoirs.

Table 10: Fixed operation and maintenance costs [€/kW]

| Technology | 2017 | 2020 | 2030 | 2040 |
|------------|------|------|------|------|
| Wind | 44 | 41 | 38 | 37 |
| Solar | 18 | 17 | 17 | 17 |
| Biomass | 63 | 63 | 63 | 63 |
| Hydro | 65 | 65 | 65 | 65 |
| Nuclear | 198 | 198 | 198 | 198 |
| Hard coal | 54 | 54 | 54 | 54 |
| Brown coal | 42 | 42 | 42 | 42 |
| CCGT | 17.5 | 17.5 | 17.5 | 17.5 |
| CCGT | 18 | 18 | 18 | 18 |

Operation and maintenance costs are extracted from [59].

Table 11: Marginal costs [€/MWh]

| Technology | 2017 | 2020 | 2030 | 2040 |
|------------|------|------|------|------|
| Wind | | | | |
| Solar | | | | |
| Biomass | 30.8 | 31.4 | 33.5 | 34.6 |
| Hydro | | | | |
| Nuclear | 7.1 | 7.1 | 7.1 | 7.1 |
| Hard coal | 28.0 | 28.0 | 52.4 | 64.6 |
| Brown coal | 23.6 | 23.6 | 48.1 | 60.3 |
| CCGT | 67.1 | 67.1 | 84.4 | 93.0 |
| CCGT | 44.8 | 44.8 | 60.1 | 66.2 |

Marginal costs are extracted from [32] and [61].

Table 12: CO₂-prices, gas prices, hard coal prices, lignite fuel costs and plant efficiencies

| | 2017 | 2020 | 2030 | 2040 |
|---|------|------|------|------|
| CO ₂ -prices [€/tCO ₂] | 20 | 20.0 | 60.0 | 80.0 |
| Gas price [€/MMBut] | 7.2 | 7.2 | 7.2 | 7.2 |
| Hard coal [€/t] | 60.6 | 60.6 | 60.6 | 60.6 |
| Fuel cost of brown coal plants [€/MWh _{el}] | 11.6 | 11.6 | 11.6 | 11.6 |
| <i>Efficiency</i> | | | | |
| Hard coal | 47 % | 47 % | 47 % | 47 % |
| OCGT | 42 % | 42 % | 42 % | 42 % |
| CCGT | 59 % | 59 % | 59 % | 59 % |

CO₂-prices, gas prices and coal prices are based on a compromise between the carbon neutral scenario and the 4 degree scenario presented in [33]. The efficiencies of the plants and fuel cost of brown coal plants are found in [32].

Table 13: Initial installed capacity [MW]

| Technology | RWE | Uniper | Vattenfall | EnBW | Fringe | Total |
|------------|-------|--------|------------|------|--------|-------|
| Wind | 0 | 0 | 19 | 400 | 44580 | 45510 |
| Solar | 0 | 0 | 0 | 0 | 40850 | 40850 |
| Biomass | 0 | 0 | 40 | 109 | 6911 | 7060 |
| Hydro | 0 | 1895 | 2600 | 1095 | 0 | 5590 |
| Nuclear | 6482 | 0 | 0 | 2712 | 1606 | 10800 |
| Hard coal | 4098 | 3200 | 2800 | 3430 | 14850 | 28380 |
| Brown coal | 12756 | 900 | 164 | 393 | 6687 | 20900 |
| OCGT | 662 | 1813 | 911 | 416 | 9236 | 13038 |
| CCGT | 2523 | 1528 | 0 | 0 | 9576 | 13627 |

Total installed capacity in Germany is found in [17] and [51]. The initial installed capacities of RWE, Uniper, Vattenfall and EnBW can be found in [57], [65], [66], [11] and [51].

Table 14: Inelastic demand in the different time segments [MWh/h]

| Segment h | 1 | 2 | 3 | 4 | 5 |
|-------------|--------|--------|--------|--------|--------|
| Q_h^{mn} | 55 000 | 40 000 | 30 000 | 20 000 | 15 000 |

Table 15: Energy constrained technologies

| f | RWE | Uniper | Vattenfall | EnBW | Fringe | Total |
|-------------------------------------|-----|--------|------------|------|--------|-------|
| Hydro, $Q_{f,HP}^{\max}$ [TWh/y] | 0 | 6.47 | 8.88 | 3.74 | 0 | 19.09 |

We assume that hydropower is the only technology with a binding energy constraint on accumulated generation. Total energy availability is found in [16]. We assume that the amount of energy in different reservoirs are distributed according to the installed capacity.

Table 16: Technical lifetime and annual phase-out rate of different technologies

| Technology | Lifetime [y] | Phase-out rate for existing plants |
|------------|--------------|------------------------------------|
| Wind | 25 | *0.0400 |
| Solar | 25 | *0.0400 |
| Biomass | 25 | 0.0400 |
| Hydro | 40 | 0.0125 |
| Nuclear | 60 | **0.0167 |
| Hard coal | 40 | 0.0250 |
| Brown coal | 40 | 0.0250 |
| OCGT | 30 | 0.0333 |
| CCGT | 30 | 0.0333 |

Technical lifetime can be found in [59]. The phase-out rate is estimated by the reciprocal lifetime.

*A considerable share of the wind and solar investments are made within the last few years [17]. Thus, we assume that no wind and solar plants are phased out before 2030.

**Germany has decided to phase out nuclear power by 2022 [2]. For simplicity, we assume a linear phase-out of installed capacity between 2017 and 2022.

Table 17: Simulation parameters

| Y_0 | μ | σ | ρ | α_1 | S | T | Utilization rate |
|-------|---------|----------|--------|------------|-----|-----|------------------|
| 1 | -0.0029 | 0.023 | 0.04 | 13.92 | 23 | 40 | 0.76 |

Power plants cannot be utilized at all times. Thus, we define a utilization rate reflecting the down time of conventional power plants and the desire to have back-up capacity available. The utilization rate is computed by dividing maximum hourly demand in Germany in 2016 by the total installed controllable capacity.

Table 18: Y_0^{grid} and γ

| | |
|---------------------|--|
| Y_0^{grid} | $Y_s - 0.3, Y_s - 0.2, \dots, Y_s + 0.3$ |
| γ | 1, 2, 2, ..., 13 |

D Determining the level of capacity payment

In implementing capacity payments, the reliability of supply is a major concern. Thus, we argue that capacity payments should be determined such that the level of installed peak load capacity, i.e. gas-fired power plant capacity, approximates the capacity found in section 5.1. Table 19 presents the installed capacity of gas-fired power plants, the share of renewables in 2040, the aggregated rationing from 2017 to 2040 found in section 5.1 and the first paragraph of section 5.3, i.e. when no capacity policies are implemented. Table 20 shows the effect of different capacity payment levels. We do not examine capacity payments above 31 000 €/MW, as these make OCGT power plants profitable even with sporadic operation.

Table 19: Installed capacity of gas-fired power plants, renewable dispatch in 2040, and aggregated rationing from 2017 to 2040 under different capacity payment levels

| | Base case | No capacity policy |
|---------------------------|-----------|--------------------|
| Gas capacity [GW] | 34 | 6 |
| Renewable dispatch | 70 % | 73 % |
| Rationing 2017-2040 [TWh] | 0 | 16 |

Table 20: Installed capacity of gas-fired power plants, renewable dispatch in 2040, and aggregated rationing from 2017 to 2040 under different capacity payment levels

| | 25 000 €/MW | | 28 000 €/MW | | 31 000 €/MW | |
|---------------------------|-------------|------|-------------|------|-------------|------|
| | Gas | OCGT | Gas | OCGT | Gas | OCGT |
| Gas capacity [GW] | 35 | 18 | 40 | 26 | 48 | 33 |
| Renewable dispatch | 48 % | 71 % | 45 % | 69 % | 42 % | 67 % |
| Rationing 2017-2040 [TWh] | 5 | 9 | 2 | 5 | 1 | 2 |

Table 20 shows that capacity payments for all types of gas-fired power plants result in high investments in gas-fired power plants at the expense of renewables. Moreover, we find that a capacity payment of 31 000 €/MW to OCGT power plants results in a small level of rationing and an installed capacity of gas-fired power plants close to that of the base case that includes minimization of rationing. We therefore argue for capacity payments of 31 000 €/MW to OCGT power plants.

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