OLIVEIRA, F.S., WILLIAM-RIOUX, B. and PIERRU, A. 2023. Capacity expansion in liberalized electricity markets with locational pricing and renewable energy investments. *Energy economics* [online], 127(B), article number 106958. Available from: https://doi.org/10.1016/j.eneco.2023.106958

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2023

Energy Economics 127 (2023) 106958

Contents lists available at ScienceDirect

Energy Economics

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

Capacity expansion in liberalized electricity markets with locational pricing and renewable energy investments

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ARTICLE INFO

Keywords:
Auctions and mechanism design
Capacity planning
Electricity markets
Game theory
Renewable energy
Stochastic methods

ABSTRACT

We study the long-term incentives for expanding production capacity in liberalized electricity markets. How does electricity market design affect the prices of energy, capacity, and social welfare? And how is this capacity market affected by the geographical features of the electricity market? Should the system operator design the capacity market to provide incentives for investment in renewable technologies? We analyze the conditions under which capacity payments and markets enable higher investment relative to an energy-only market in which generators sell electricity but not capacity. We show that capacity markets benefit consumers and investors by increasing investment and reliability and capping peak prices. We prove that generators benefit from owning a portfolio of peak and baseload plants and show that investment strategies must consider regional capacity auctions. We demonstrate that a capacity payment per technology increases investment in renewable technologies and leads to the early retirement of older, carbon-emitting technologies. Regional capacity investment targets effectively decrease energy prices and significantly increase investment in renewable technologies.

1. Introduction

A significant aim of electricity market liberalization is to attract private investment. New policies and legislation are attempting to attract private players to invest in the necessary capacity to meet reliability requirements. Regulators are also actively imposing compulsory divestments to reduce new firms' barriers to entry and increase the number of generation companies in the electricity market. This topic has been the subject of intensive debate, focusing on capacity markets' role in improving investment signals, curtailing barriers to entry, and increasing market efficiency.

The electricity systems, for this reason, have developed two interdependent markets: the energy market, where electricity is traded, both spot and forward; and a capacity market in which generation capacity is purchased, typically by the system operator (using an auction), to reward investment in capacity. For example, Hickey et al. (2021) a pan-European study of the variation in capacity payments, showing these are very diverse across Europe but essential for generators to recover the *missing money*, i.e., the insufficient returns from the energy-only market, so that the capital costs are recovered, and investments are profitable.

Energy-only markets face the major problem that the generators' operating and capital costs can be recovered only through electricity and ancillary service prices. Thus, generators' profitability relies on the scarcity premium charged during peak demand hours (e.g., Bublitz et al., 2019; Finon and Pignon, 2008; Finon et al., 2008; Joskow, 2008; NERA, 2011; Roques, 2008). To recover their fixed costs, generators expect electricity prices to be very high for a few hours every year. At these times, available capacity is minimal, and the probability of a general blackout is higher than is acceptable to the regulatory authorities. Most importantly, these periods of high prices and reduced capacity may cause substantial losses to many other industries that depend on a reliable electricity supply. This issue is crucial to the future of private investment in electricity markets.

The primary motivation for this project is the call for investment in new capacity in liberalized electricity markets. This process is very complex, including privatizing existing assets once they are divested to smaller generators. It also incorporates investment in new technologies and the additional capacity required to meet the growing electricity demand. We must consider an extensive network of geographically heterogeneous generation assets in which zonal pricing is used to facilitate capacity expansion where necessary. To assess the challenges of capacity investment we introduce an equilibrium model that captures

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https://doi.org/10.1016/j.eneco.2023.106958
Received 5 May 2021; Received in revised form 26 March 2023; Accepted 15 August 2023
Available online 20 September 2023

locational pricing across zonal energy and capacity markets in which generators sell capacity across to serve peak demand. The model also considers fuel subsidies, the zonal transmission network, demand, and cost uncertainties, Cournot oligopolists, and smaller fringe generators.

The research questions addressed in this article are as follows. How does electricity market design affect market performance, including prices of energy and capacity and the value of the different generation technologies? What are the benefits of including a market for capacity as part of the options available to generators? Does the capacity market increase or decrease market power and social welfare? And how is this capacity market affected by the geographical features of the electricity market? Finally, how can the system operator design the capacity market to provide incentives for investment in renewable technologies?

This article is the first to analyze the interaction between investment decisions and locational pricing in oligopolistic markets (for capacity and energy). As, typically, the distributions of electricity demand and supply are very heterogeneous, it is essential to fully characterize the effects of locational issues on investment and the energy and capacity markets. For this reason, we develop a stochastic model with locational pricing to capture expected variations in demand and renewable energy production.

The practical implications of this project are twofold. From the perspective of policymakers, the model can help in capacity planning. The model is useful for several types of policy analysis. First, it can analyze the effects of introducing capacity markets on electricity prices and capacity investment within the privatization process. Second, it allows policymakers to explore the best pathway from the current market to the final objective for the country and consumers using simulations. This pathway is likely to take decades to complete. Finally, the model can show the effects of market mechanism design on production reliability, consumer surplus, and renewable investments. Thus, it can help policymakers strike a balance between these three components.

Second, from the perspective of new investors, this tool can help to assess the impacts of different market rules considering location issues. Investors can investigate these rules' effects on the value of the assets being privatized and the new capacity to be added to the system. We also analyze possible investment portfolio strategies. We explain how a prominent investor can optimally combine different production technologies to increase profitability and use capacity markets (and payments) to decrease investment risk.

This study also contributes to the literature by developing an innovative methodology. We analyze the interaction between the capacity and energy markets in a large competition model. The model accounts for endogenous oligopolistic pricing and locational capacity auctions. Moreover, it considers different technologies and transmission constraints. It is the first model to consider the interactions between the capacity and energy markets while accounting for transmission constraints and uncertainty (including risk-neutral generators and arbitrageurs).

This new methodology is necessary to analyze the impacts of the interactions between locational pricing and capacity markets on firms' optimal investment strategies. To this end, we solve a Nash equilibrium with oligopolistic generators, formulated as a mixed-complementarity problem (e.g., Hobbs and Pang, 2004; Metzler et al., 2003; Murphy and Smeers, 2005; Oliveira, 2017; Pineau and Murto, 2003). The model comprises several incumbent generators, modeled as Cournot players, with a competitive fringe. Each generator aims to maximize its profit. The model also includes an independent transmission system operator (TSO), whose main task is managing the electricity network. Finally, we incorporate an implicit market operator that organizes the energy and capacity markets and a representative arbitrageur of price imbalances between different regions.

The remainder of this article is structured as follows. Section 2 provides a review of the literature on capacity markets. In Section 3, we introduce the market structure and profit functions represented in the model. Section 4 explains the computation of the market equilibrium and summarizes the model's basic properties. Section 5 uses the model to analyze the hypothetical case of a restructuring of the Saudi electricity sector. Section 6 concludes.

2. Review of the literature on investment in electricity generation capacity

This section revises the literature on modeling investment in electricity markets, including different incentive mechanisms. Section 2.1 summarizes different modeling approaches to study investment in capacity; Section 2.2 revises the problem when there is only an energy market for electricity, but the capacity market does not exist; Section 2.3 revises the literature, which simultaneously includes an energy and a capacity market.

2.1. *Investing in capacity*

Investment in capacity has been researched from different perspectives, including capacity expansion games and auction mechanisms for capacity pricing (e.g., Bunn and Oliveira, 2008, 2016; Hall and Liu, 2013; Karabati and Yalçin, 2014). This problem has been studied from the generator's perspective, using mixed-integer linear programming (e.g., Chaton and Doucet, 2003; Kazempour et al., 2011) and from the technology's perspective (e.g., Eager et al., 2012; Ehrenmann and Smeers, 2011; Hach et al., 2016; Ritzenhofen et al., 2016).

There are three major approaches to studying the stochastic capacity expansion game: the closed-loop, open-loop, and Markov models. In the closed-loop model, firms commit to an irreversible investment in the first stage and produce in the second stage. This model is particularly appropriate for analyzing short-term problems when the decisions made in the first stage cannot be revised subsequently (e.g., Genc and Zaccour, 2013; Murphy and Smeers, 2005; Oliveira, 2017; Jin and Ryan, 2014a, 2014b; Wogrin et al., 2013; Zottl, 2010; Gonzales-Romero et al., 2019). In the open-loop model (e.g., Pineau and Murto, 2003), firms simultaneously decide their investment and production levels. Thus, investment is always reversible and adjustable to the required output. In the Markov models (e.g., Garcia and Shen, 2010; Murto et al., 2004; Oliveira and Costa, 2018), production is constrained by existing capacity and investment (which is available after some delay).

Of these three alternatives, we use the open-loop model of an oligopoly. We analyze how the interaction between the capacity and energy markets shapes investment and prices in the electricity market, considering locational pricing. We choose an open-loop model for three main reasons. First, it allows us to model the strategic interdependence between the different firms' investment strategies. Second, it facilitates the realistic representation of the investment policies available to firms. Third, it is transparent and relatively easy to validate analytically.

Hourly price spikes can cause extreme uncertainty and are socially challenging to accept. Moreover, in energy-only markets, the expected wholesale and ancillary services prices and the number of production hours never rise enough to lead to the required investment in capacity. This short-run problem is associated with sharp price rises and the central issue of energy-only markets (Jaffe and Felder, 1996; Joskow, 2008). These failures can result in electricity price spikes so that generators can recover their investment costs and justify new investments. Given the low probability of these price spikes, however, generators face higher risk and uncertainty on their returns. Generators' profitability is capped if the regulator imposes price caps to control price spikes. The capacity shortage caused by this lack of investment may lead to more frequent shortages and higher average energy prices.

2.2. *Investing when capacity remuneration mechanisms exist*

This failure of energy-only markets to deliver the capacity necessary to maintain supply security has resulted in different types of payments to reward capacity investments (Crampton and Stoft, 2005; Gottstein and

Schwartz, 2010; Bublitz et al., 2019). Such charges include strategic reserves, capacity obligations, capacity payments (e.g., Galetovic et al., 2015; Fabra, 2018), capacity auctions, and reliability options (Finon and Pignon, 2008; Traber, 2017). Additionally, the form of an energy-only market may be modified to account for capacity availability. For example, the Texas market, regulated by the Electric Reliability Council of Texas (ERCOT), features an operating reserve demand curve. This curve increases energy prices in the day-ahead electricity market as capacity reserves decline (Zarnikau et al., 2020).

Capacity markets do not rely on the energy market to define the adequate investment level. Instead, they are based on a technical assessment of future electricity demand and the most efficient electricity-generation technology required to meet this demand. This process provides generators with a steadier revenue stream. Although it may increase wholesale prices, this mechanism offers higher reliability and lower price volatility overall. Each generator bids for its capacity at a fair price in the capacity market to compensate for the investment. Such auction-based capacity market sales usually occur several years before the date of electricity delivery. They aim to pay generators for investing in capacity, allowing them to cover some of the fixed costs of generation. The U.K.'s Department of Energy and Climate Change (2016) describes the main objectives of a capacity market. First, it must provide incentives for sufficient capacity investments to meet the regulator's reliability standards, and second, it should achieve supply security at a minimal cost. Several studies show that capacity markets can achieve these objectives if designed and implemented correctly (Creti and Fabra, 2007).

Besser et al. (2002) discuss the need for capacity obligations as a design standard given the political reality of liberalized electricity markets. Moreover, a recent ERCOT data study demonstrates that capacity payments can benefit consumers under perfect competition (Bajo-Buenestado, 2017). Capacity payments have also been used in the U.K. and Spain. However, in many cases, they have led to greater investment levels than observed in an energy-only market, decreasing scarcity rents (NERA, 2011; Roques, 2008). The capacity payments are estimated before (after) electricity generation in Spain (in the U.K). Nonetheless, they were subject to market manipulation in both cases. Khezr and Nepal (2021) analyze capacity markets under decreasing marginal costs, reporting that marginal and average cost-based pricing methods are not viable and recommending lump sum capacity payments so that generators can be profitable in the long term.

Capacity markets can be designed in various ways. A procurement agency can buy the expected required capacity (fixed and estimated by the agency) through an auction, as in the Pennsylvania-New Jersey-Maryland Interconnection in the US. Alternatively, the agency can design an explicit capacity demand function. In this case, an auction is also held. The buying price is a function of the generators' bids and the demand function designed by the buying agency. Capacity auctions in New England (U.S.) and the U.K. use this design (e.g., Statutory Instruments, 2014). Brown (2018) reported that a responsive capacity demand function is essential to reduce market power and increase consumer surplus. Bialek and Ünel (2022) study the interaction between green generation subsidies and capacity markets, proving that the heterogeneity of generation and the interaction between capacity and energy markets are essential in determining the effectiveness of the subsidies and market reforms. Although capacity payments have traditionally operated independently of technology, their use in the U.S. to procure certain technologies has recently been debated. The issue has been raised in cases where carbon pricing is insufficient to encourage the transition to renewable generation technologies (Spees et al., 2017, 2019). One example is the Forward Clean Energy Market variations in New England's wholesale electricity market.

However, such capacity markets can also be flawed for three main reasons. First, they may lack a connection to energy markets and fail to incorporate new capacity. Second, they may provide insufficient remuneration for investments in peaking capacity (i.e., mainly used to serve high-demand periods) owing to the short planning horizon. Third, they may fail to consider congestion charges and locational issues (Briggs and Kleit, 2013; Crampton and Stoft, 2005; Roques, 2008). A recent survey of capacity markets in the U.S. (Bhagwat et al., 2016) shows that reliability goals were achieved at the expense of economic efficiency.

Lynch and Devine (2017) and Devine and Lynch (2017) use a stochastic mixed complementarity model, the same modeling apparatus used in this article. Lynch and Devine (2017) examine the impact of refurbishment on electricity prices and generation investment, reporting that capacity payments increase reliability when refurbishment is not possible; when these are possible capacity payments and reliability options have similar results. Furthermore, Devine and Lynch (2017) propose a capacity payment that induces the truthful revelation of the generator's reliability.

In this article we use a stochastic mixed complementarity model. Our work extends and differs from theirs in three significant ways. First, we include transmission with locational capacity markets (or payments) by considering the TSO and arbitrageurs' activities. Second, we analyze the model's properties and show the effects of different assumptions regarding the generators' behavior and the market operator's (principal buyer's) decisions on these properties. Third, we model capacity auctions and payments, including technology-dependent capacity markets.

3. Description of the model of energy and capacity markets

We will now describe the model used to represent the interactions among agents in the energy and capacity markets. This includes representing independent power generation companies competing to serve zonal energy markets. The model analyzes capacity expansion in the Saudi Arabian power sector in numerical simulations presented in Section 6. This includes a simulation of an hypothetical unbundling of the current generation assets of the state-owned Saudi Electricity Company (SEC) into four independent regional generators.

The model incorporates the generators' investment and retirement decisions in different regional capacity markets for various technologies. We develop capacity market scenarios for the Saudi market to incentivize the development of renewable technologies, including solar and wind, and ensure a sufficient supply of conventional capacity to satisfy regional reserve requirements. Before presenting the calibration and numerical simulation of the Saudi power market, we derive general analytical results of the model in Section 5. These results help to describe general interactions between the market design and the behavior of the different players in perfect competition and a Cournot oligopoly. They are used to interpret the numerical results presented in Section 6 and inform the research questions, i.e., the impact of electricity and capacity market design on the decisions made by generators, electricity prices, supply and value of capacity, and consumer and social welfare.

The indices, variables, and coefficients used to construct the model are all defined in Table 1. The agents in the model include a group of competing generators and a competitive fringe, represented by the index i and j. We postulate the existence of a market organizer who is responsible for energy and capacity procurement. This organizer also forecasts demand and procures new capacity years ahead of delivery. Procurement can take the form of auctions or bilateral trading.

A TSO is introduced to coordinate transmission services between regional markets or zones, indexed by r. Finally, an independent arbitrageur ensures that the market is in equilibrium. Electricity generation from technology h (Q_{ihrls}) and capacity expansion decisions, including investment (I_{ihr}) and retirement (Y_{ihr}), are decentralized and controlled by profit-maximizing generators. They determine their production levels in different demand segments, indexed by l and ll, for each block of hours in the regional energy markets. The set s represents demand scenarios with probabilities ν_s that sum to one.

We start by defining the market-clearing conditions associated with the total demand for energy (1), capacity (2), and transmission services

Table 1
Sets and variables used in the model.

	List of indices used in the model
h	Electricity generation technologies
i, j	Firms, including generators and a competitive fringe
l, ll	Demand segments each year
n	Transmission lines connecting adjacent zones
u	Direction of the flow on a transmission line between zones
r	Regions in the zonal market
s	Scenarios capturing the stochastic components of demand and supply behaviors
	List of variables used in the model
π_i	Generator i's profit [million \$]
K_{ihr}	Available capacity of firm i for technology h in region r [GW]
P_{rls}	Energy market price in region r for demand segment l in scenario s [\$/KW]
δ_{hr}	Capacity market price for technology h in region r [\$/KW]
	Primal variables
	Generator
I_{ihr}	Capacity built by firm i for technology h in region r [GW]
Q_{ihrls}	Energy produced by firm i from technology h in region r for demand segment l in scenario s [GW]
S_{irls}	Energy sold by firm i in region r for demand segment l in scenario s [GW]
Y_{ihr}	Capacity retired by firm i for technology h in region r [GW]
	Arbitrageur
A_{rls}	Arbitrage into (+) or out of (−) zone r in demand segment l and scenario s [GW]
	TSO
L_{rls}	Load injected into (+) or extracted from (−) node r [GW]
T_{nls}	Energy sent across transmission line n [GW]
	Dual variables
ρ_{rls}	Transmission price for the net load (+/−) in region r for demand segment l and scenario s from Eq. (3)
η_{ihr}	Shadow price (marginal value) on the firm's retirement constraint (4.3)
λ_{ihrls}	Shadow price on the firm's capacity constraint (4.4)
γ_{ils}	Shadow price on the firm's aggregate sales constraint (4.5)
ω_{nlsu}	Shadow price on the lower bound of the transmission variable in constraint (5.2)
τ_{nls}	Shadow price on the TSO's transmission capacity constraint (5.3)
ζ_{ls}	Free variable from the arbitrage identity (6.2)
	Demand coefficients
a_{rls}	Intercept of the inverse demand curve in (1)
b_{rls}	Slope of the inverse demand curve in (1)
θ_{hr}	Intercept of the capacity auction in (2)
ξ_{hr}	Slope of the capacity auction in (2)
ν_s	Probability of each stochastic demand scenario s
	Generators' coefficients
c_{hrls}	Marginal cost of technology h in region r, demand segment l and scenario s [\$/KW]
f_h	Retirement cost of technology h [\$/KW]
o_h	Fixed operation costs of technology h [\$/KW]
w_h	Investment cost of technology h [\$/KW]
k_{ihr0}	Existing generation capacity owned by the generators [GW]
	TSO's coefficients
ϕ_{nl}	Marginal cost of transmission line n in demand segment l [\$/KW].
χ_n	Transmission capacity of line n [GW]
$PTDF_{nru}$	Power transfer distribution function for line n and zone r in direction $u \in \{+,-\}$

(3). Later in this section, we define the complex optimization problems of the generators (4), TSO (5), and arbitrageur (6). The complete MCP that clears the energy, capacity, and transmission services markets are derived in Section 4. As a convention, we list the orthogonal Lagrange multipliers (dual variables) associated with each constraint on the right-hand side of the corresponding equation.

3.1. Market clearing conditions

$$P_{rls} = a_{rls} - b_{rls}\sum_j S_{jrls} - b_{rls}A_{rls} \quad \forall rls \tag{1}$$

$$\delta_{hr} = \theta_{hr} - \xi_{hr}\sum_i K_{ihr} \quad \forall hr \tag{2}$$

$$L_{rls} = \sum_i S_{irls} + A_{rls} - \sum_i\sum_h Q_{ihrls} \quad \perp \rho_{rls} \in \mathbb{R} \quad \forall rls \tag{3}$$

Let P_{rls} be the energy price in dollars per kilowatt (\$/KW). Eq. (1) defines the zonal energy price as a linear function of total zonal sales S_{irls} and regional arbitrage A_{rls}. Here, a_{rls} and b_{rls} are the intercepts and slopes, respectively. These parameters provide a linear approximation of the demand response in the wholesale market. The model implicitly assumes that the wholesale price is passed on to consumers. Eq. (2) defines the capacity price δ_{hr} in dollars per kilowatt as a function of the capacity of technology h sold in region r. This capacity is sold and is always available to run when needed. This equation is based on the work of Crampton and Stoft (2005), Finon and Pignon (2008), NERA (2011)), and Brown (2018). All these studies discuss a downward-sloping demand function in the capacity market from theoretical and practical perspectives. We set up separate capacity auctions for each technology h. This allows us to set up specific capacity markets for renewable and conventional technologies. We use the intercept and slope, given by θ_{hr} and ξ_{hr}, respectively, to parameterize the corresponding capacity auctions.

Eq. (3) introduces the central auction for transmission services (POOLCO) for the transfer of energy between zones, following Hobbs (2001). The TSO organizes this auction. The free variable L_{rs} defines the zonal load balance as the sum of energy sales and arbitrage less the aggregate energy generated in zone r. The dual variable ρ_{rls} determines the price of transmission services in the POOLCO. It is a free variable representing the price paid to generators for supplying energy to the transmission grid or price paid by generators to pull energy from the grid to sell to customers in each region. The difference between the zonal prices defines the transmission price charged by the TSO.

These prices are treated as exogenous within the generators' and the TSO's optimization problems. This approach is similar to the Bertrand assumption for transmission rights, e.g., Neuhoff et al. (2005). We use this approach to avoid solving a more difficult two-stage model for transmission services. By allowing generators to sell energy at several locations through virtual transmission rights, we can implement the two-stage problem as an MCP (Metzler et al., 2003).

3.2. The generator's problem

The strategic generator's problem is presented in Eq. (4). The generator aims to maximize its expected profits π_i, as in Eq. (4.1). The profits include electricity sales $\sum_{rls} P_{rls}S_{irls}\nu_s$ less production costs $\sum_{hrls} c_{hrls}Q_{ihrls}\nu_s$. They also include the revenue earned in the capacity market $\sum_{hrm} K_{ihr}\delta_{rh}$ minus investment costs $\sum_{hr} w_h I_{ihr}$, fixed maintenance costs $\sum_{hr} o_h K_{ihr}$, retirement costs $\sum_{hr} f_h Y_{ihr}$ and transmission fees $\sum_{rls}\rho_{rls}\left(S_{irls} - \sum_h Q_{ihrls}\right)\nu_s$. Regional marginal costs c_{hrls} are proportional to the number of hours in each demand segment. They can be varied by scenario to capture increased production costs during high-demand periods. Each scenario has an associated probability ν_s that sums to one. As a convention, the orthogonal Lagrange multipliers (dual variables) associated with each constraint are listed on the right of the corresponding equation.

Generator's problem: (4)

$$\begin{aligned} max\pi_i = &\sum_r\sum_l\sum_s\left(P_{rls}S_{irls} - \sum_h Q_{ihrls}c_{hrs}\right)\nu_s \\ &+\sum_r\sum_l \delta_{hrl}\sum_h K_{ihr} \\ &-\sum_h\sum_r w_h I_{ihr} - \sum_h\sum_r o_h K_{ihr} - \sum_h\sum_r f_h Y_{ihr} \\ &-\sum_r\sum_l\sum_s \rho_{rls}\left(S_{irls} - \sum_h Q_{ihrls}\right)\nu_s \end{aligned} \quad \forall i \tag{4.1}$$

subject to:

$$Q_{ihrls} \le K_{ihr} \quad \perp \lambda_{ihrls} \ge 0 \quad \forall ihrls \tag{4.2}$$

$$Y_{ihr} \le k_{ihr0} \quad \perp \eta_{ihr} \ge 0 \quad \forall ihr \tag{4.3}$$

$$\sum_r \sum_h Q_{ihrls} \ge \sum_r S_{irls} \quad \perp \gamma_{ils} \ge 0 \quad \forall ils \tag{4.4}$$

$$K_{ihr} = k_{ihr0} + I_{ihr} - Y_{ihr} \quad \forall ihr \tag{4.5}$$

$$Q_{ihrls} \ge 0, I_{ihr} \ge 0, Y_{ihr} \ge 0, S_{irls} \ge 0.$$

Eq. (4.2) reflects the capacity constraint for energy generated from each technology. Eq. (4.3) states that capacity retirements are limited to the capacity owned within the current stock of available technologies per region. Retirements can be interpreted as generators' stranded assets when the market is liberalized. Eq. (4.4) limits the generator's total energy sales to its aggregate production. Eq. (4.5) is the identity for the available capacity, given by K_{ihr}.

3.3. The transmission market

Next, we describe the TSO's and arbitrageur's problems, which optimize zonal power transmission and arbitrage, respectively, in each demand segment and scenario. Zones are connected by transmission lines, which are indexed by n. A direct current optimal power flow (DCOPF) model linearizes the alternating current flow equations. The model approximates Kirchhoff's current and voltage laws without line losses (Gabriel et al., 2013; Hobbs and Pang, 2004).

The TSO's problem: (5)

$$max\mu_{ls} = \sum_r L_{rls}\rho_{rls} - \sum_n \sum_l \varphi_{nl} T_{nls} \tag{5.1}$$

subject to:

$$T_{nls} \ge \sum_r PTDF_{nru} L_{rls} \quad \perp \omega_{nlsu} \ge 0 \quad \forall nlsu \tag{5.2}$$

$$\chi_n \ge T_{nls} \quad \perp \tau_{nls} \ge 0 \quad \forall nls \tag{5.3}$$

$$T_{nls} \ge 0.$$

The TSO's problem, given by eq. (5), involves the efficient allocation of transmission capacity. The TSO charges the fee ρ_{rl}, taken from Eq. (3), as a price-taker in the POOLCO market for the total load balance in each region, L_{rls}. The objective function, Eq. (5.1), maximizes profits μ_{ls} defined as revenues from the sale of transmission services to generators and arbitrageurs (first term) less variable transmission costs φ_{nl} (second term) for the transfer of energy between nodes along transmission lines n. Non-negative transmission values T_{nls} are evaluated using the power transfer distribution factors ($PTDF_{nru}$), where the index $u \in \{+,-\}$ represents the two possible flow directions in the DCOPF model ($PTDF_{nr-} = -PTDF_{nr+}$). It is used in constraint (5.2), mapping the net loads in each zone as lower bounds on transmission. Finally, Eq. (5.3) defines the transmission capacity constraints, where χ_n is line n's available capacity and the dual variable τ_{nls} is the line congestion rent.

This representation of the TSO's problem differs from models of investment in transmission using bi-level (e.g., Gonzales-Romero et al., 2019) and multi-level (e.g., Jin and Ryan, 2014a, 2014b) approaches in several important ways. First, we consider existing transmission capacity only, and the role of the TSO is to compute the transmission prices. Second, in our model, the TSO assumes that the pricing of transmission and energy coincide. In contrast, both Gonzales-Romero et al. (2019) and Jin and Ryan (2014a, 2014b) consider the TSO to be a leader who can propose generation investments. Gonzales-Romero et al. (2019) assumes that there is only one generator per node, whereas we model competition in each node. We do not model intraday operations, considering only the performance of the different technologies in a typical year.

3.4. The arbitrageur's problem

Eq. (6.1) shows that the arbitrageur aims to maximize profits σ_{ls} by buying one region's excess energy ($A_{rls} < 0$) and selling it to neighboring regions ($A_{rls} > 0$) at a higher price. The arbitrageur behaves as a price-taker in both the energy and transmission markets. In the transmission market, the arbitrageur ensures that generators cannot increase their profits using zonal price arbitrage, even with imperfect competition. Eq. (6.2) sets the balance of arbitrage across all zones.

Arbitrageur's problem: (6)

$$max\sigma_{ls} = \sum_r (P_{rls} - \rho_{rls}) A_{rls} \quad \forall ls \tag{6.1}$$

Subject to:

$$\sum_r A_{rls} = 0 \quad \perp \zeta_{ls} \in \mathbb{R} \quad \forall ls \tag{6.2}$$

4. Computing the Nash equilibrium

This section describes the computation of the Nash equilibrium for the electricity market game. We then summarize the properties of the model that are relevant to capacity market operations and the behavior of the firms. Additionally, firms may implement different strategies owing to both their size and the types of generation technologies that they own, such as operating as a competitive price-taker or within a Cournot oligopoly as a price-maker. To capture these different behaviors, we derive an MCP for the electricity market game using conjectural variations that define a generator's expectation of its competitors' reactions to changes in its investments and energy sales in the wholesale market.

We explore the case of large oligopolistic firms organized as a Cournot oligopoly with a competitive fringe, applying the corresponding conjectural variations for each. Devine and Siddiqui (2020) address issues when modeling this type of market structure in an MCP, including myopic and contradictory behavior, such as the competitive fringe becoming a dominant firm by investing and producing more than the oligopoly. They propose instead using an Equilibrium Problem with Equilibrium Constraints (EPEC) to model such a market with price-making and price-taking firms. To avoid solving a more complex EPEC, we solve the MCP by applying a barrier of entry constraints on the competitive fringe, as discussed in Section 5. In the current section, we derive the optimality conditions for a given behavioral assumption within our MCP approach.

Let V_i and Z_i be the conjectural variations of each generator concerning its energy sales and investments, respectively. We assume that the conjectural variation in energy sales is independent of the scenario, region, and demand segment. Then, this conjectural variation is represented by $V_i = \sum_{j \ne i} \partial\left(\left(S_{jrls} + \partial A_{rls}\right)\right) / \left(\partial S_{irls}\right)$. Additionally, we assume that the conjectural variation in investments is independent of technology and region and that firms' investment and retirement strategies are the same. Then, this conjectural variation is represented by $Z_i = \sum_{j \ne i} \left(\partial I_{jhr}\right) / \left(\partial I_{ihr}\right) = \sum_{j \ne i} \left(\partial Y_{jhr}\right) / \left(\partial Y_{ihr}\right)$. We have assumed that $V_i = Z_i$ throughout the article, as we expect that the conjectures regarding production and investment are the same because these define the behavior of price-taking and strategic players. It would not be consistent for a player to be strategic in one market (capacity or energy), but behave as a price taker in the other market (energy or capacity).

We consider stylized cases for the conjectural variations. Specifically, we set $V_i = -1$ for the competitive fringe and $V_i = 0$ (i.e., the Cournot conjecture) for the other strategic players (generators). These simplifying assumptions help make the model more tractable for deriving analytical results and conducting numerical simulations. For the sake of brevity, we do not describe or justify this value selection. Doing so would detract from the key insights derived from studying stylized behaviors (perfect competition and Cournot). However, the conjectural variations may also be differentiated based on region, demand segment (peak versus baseload), and technology.

The Lagrangian functions of the generator's, arbitrageur and TSO's problems are shown in Appendix B. The dual equations of the Karush–Kuhn–Tucker (KKT) conditions for the generator's, arbitrageur and TSO's problems are shown in Eq. (7).

TSO's Problem: (7)

$$\gamma_{ils} + \rho_{rls} - c_{hrls} - \lambda_{ihrls} \leq 0 \quad \perp Q_{ihrls} \geq 0 \quad \forall ihrls \tag{7.1}$$

$$\delta_{hr} - \xi_{hr}(1+Z_i)K_{ihr} + \sum_l \sum_s \lambda_{ihrls} v_s \leq w_h + o_h \quad \perp I_{ihr} \geq 0 \quad \forall ihr \tag{7.2}$$

$$-(\delta_{hr} - \xi_{hr}(1+Z_i)K_{ihr}) - \sum_l \sum_s \lambda_{ihrls} v_s - \eta_{ihr} \leq f_h - o_h \quad \perp Y_{ihr} \geq 0 \quad \forall ihr \tag{7.3}$$

$$P_{rls} - b_{rls}(1+V_i)S_{irls} - \rho_{rls} - \gamma_{ils} \leq 0 \quad \perp S_{irls} \geq 0 \quad \forall irls \tag{7.4}$$

$$\rho_{rls} = \sum_n \sum_u PTDF_{nru} \omega_{nlsu} \quad \perp L_{rls} \in \mathbb{R} \quad \forall rls \tag{7.5}$$

$$\sum_u \omega_{nlsu} \leq \varphi_{nl} + \tau_{nls} \quad \perp T_{nls} \geq 0 \quad \forall nls \tag{7.6}$$

$$P_{rls} + \zeta_{ls} = \rho_{rls} \quad \perp A_{rls} \in \mathbb{R} \quad \forall irls \tag{7.7}$$

Eqs. (7.1) to (7.4) are derived by imposing the condition that the gradient of the generator's Lagrangian function equals zero in the optimal solution. In other words, the partial derivatives concerning Q_{ihrls}, I_{ihr}, Y_{ihr} and S_{irls} should equal zero, as the optimal solution should be stationary. Eqs. (7.5) and (7.6) are the stationarity conditions from the TSO's problem with respect to L_{rls} and T_{nls}, respectively. Combined, they define the zonal transmission price ρ_{rls} by mapping the line transmission costs φ_n and congestion rents τ_{nlsu} through the PTDF. Eq. (7.7) is derived by imposing the condition that the gradient of the arbitrageur's Lagrangian concerning A_{rls} is equal to zero. This assumption enforces the no-arbitrage condition, ensuring the same differential between the energy and transmission prices in zones r and r', that is, $P_r^{'}ls - P_{rls} = \rho_{r'ls} - \rho_{rls}$.

We calculate the Nash equilibrium that clears both the energy and capacity markets. To do so, we incorporate the inverse demand functions, given by Eqs. (1) and (2), and the POOLCO market condition, given by Eq. (3). We also take the original identities and primal constraints from the generators' problem, given by Eqs. (4.2) to (4.5). Finally, we use the TSO's capacity constraints, given by Eqs. (5.2) and (5.3), and the no-arbitrage condition, given by Eq. (6.2). The complete set of KKT conditions defines the open-loop MCP model, which can be solved as a single mathematical problem.

5. Analytical results

We use the MCP model to analyze the interactions between the market design and the different players' behavior. The analytical results presented below partially characterize the results that can be observed in real markets. They are essential for understanding and explaining the computational results presented in the next section. The main advantage of this method is that it allows us to derive general effects that are not case-dependent and may be applied to other countries.

We begin by examining the case of a marginal technology, such as a peaking plant. We assume that this plant has a sufficiently large capacity, so production is not constrained. We also study the case of a baseload plant, which sells its total output to all market segments throughout the year. In this section, we assume that there is only one market segment, m, and one technology, h. This setting represents times when capacity is scarce. All proofs are provided in Appendix A.

Lemma 1 shows that the energy and capacity markets are interdependent without capacity constraints. The supply of electricity is only affected by the short-term marginal cost and the marginal firm's ability to profit by withholding production from the energy market.

Lemma 1. Consider an unconstrained marginal plant h, $0 < Q_{ihrls} \leq K_{ihr}$ owned by generator i in region r, segment l, and scenario s, such that $S_{irls} \geq 0$. This plant sets its energy sales equal to $S_{irls} = \frac{P_{rls} - c_{hrls}}{b_{rls}(1+V_i)}$ and its installed capacity equal to $K_{ihr} = \frac{\delta_{hr} - w_h - o_h}{\xi_{hr}(1+Z_i)}$.

Lemma 2 shows that generator i is a price taker in the energy market when the plant is working at total capacity. The generators' rent per megawatt-hour sold equals the shadow price of the capacity $\lambda_{ihrls} = P_{rls} - b_{rls}(1+V_i)S_{irls} - c_{hrls}$. The practical implication of this result is that baseload plants benefit from a system in which marginal plants operate at higher heat rates and overall energy costs and can profitably withhold production from the energy market. Lemma 2 indicates that the capacity price does not need to cover fixed costs. Instead, the baseload plant benefits from having higher rents in the energy market because the peaking plant's marginal value sets the pricing.

Lemma 2. A plant working at full capacity earns rent in the energy market that equals the expected capacity shadow price $\sum_l \sum_s \lambda_{ihrls} v_s = w_h + o_h + \xi_{hr}(1+Z_i)K_{ihr} - \delta_{hr}$.

Theorem 1 describes the relationship between the pricing strategies of generator i. We assume this generator owns an unconstrained peak plant (p) and a constrained baseload plant (b). In equilibrium, the expected shadow price of the baseload plant, $\mathrm{E}(\lambda_{ibrls}) = \sum_l \sum_s \lambda_{ibrls} v_s$, equals the difference between the baseload and peak fixed costs. Thus, the capacity depends on the differences between the fixed costs of the baseload (higher) and peak plants per hour.

Part (a) of Theorem 1 illustrates the trade-off between *the capacity price received by the baseload plant* and *the expected energy price that the peak plant sets*. Thus, when selecting the energy price, the generator can also cover the baseload plant's fixed costs using the peak plant. Moreover, part (b) of Theorem 1 represents the baseload plant's capacity price as a function of three factors. These factors are the *baseload plant's* production and investment costs, the generator i's market power in the capacity market, and the peak plant's expected marginal production costs. The higher the marginal plant's expected cost is, the lower the capacity price of the baseload plant is. Thus, if the marginal plant's variable operating cost is higher, a higher proportion of the baseload plant's production and investment costs can be recovered in the energy market. As a result, the capacity price is lower.

Theorem 1. *For generator i, which owns a baseload plant b and a peak plant p*:

a) $E(P_{rls}) = w_b + o_b + \xi_{br}(1+Z_i)K_{ibr} + E(b_{rls}(1+V_i)S_{irls}) + E(c_{brls}) - \delta_{br}$.
b)

$$\delta_{br} = w_b + o_b + \xi_{br}(1+Z_i)K_{ibr} + E(c_{brls}) - E(c_{prls}).$$

Theorem 1 implies that a generator operating both marginal baseload and peaking plants and exhibiting Cournot behavior ($V_i = 0, Z_i = 0$) can game the market, increasing energy and capacity prices (in a capacity auction). The practical implication of this result is that promoting competition among marginal producers can also increase large baseload generators' output.

To understand the interaction between the capacity and energy markets, we need to examine the demand segments where market disruption is possible. Such a disruption may occur if the marginal plant generates electricity at full capacity and a generator goes offline or if demand exceeds capacity. Theorem 2 derives a relationship between energy and capacity prices in which capacity payments are made only to the available capacity in the disrupted segments. The energy price depends on the capacity price and the parameters used to design the capacity auction, as Corollaries 1, 2, and 3 summarize.

Theorem 2. Assume that region r is isolated from the rest of the transmission system at a time m when demand exceeds r's installed capacity. The energy and capacity prices are such that $P_{rls} = a_{rls} - \frac{b_{rls}\theta_{hr}}{\xi_{hr}} + \frac{b_{rls}}{\xi_{hr}}\delta_{hr}$.

Corollary 1. The capacity and energy prices positively correlate in a capacity auction. Compared to other regions, the capacity price is lower in regions with higher installed capacity relative to demand. The energy price is also lower in these regions in the case of a disruption. The opposite holds in regions with lower installed capacity).

Corollary 2. The higher the slope (ξ_{hrm}) of the capacity auction is, the higher the energy price is if a disruption occurs.

Corollary 3. The higher the intercept (θ_{hrm}) of the capacity auction is, the lower the energy price is if a disruption occurs.

Theorem 3 shows that the design of the capacity market is also a determining factor in the success of technologies. The capacity payment may ensure a technology's survival if the expected marginal short-run loss is less than the investment and plant retirement costs.

Theorem 3. Assume that $\delta_{hr} - \xi_{hr}(1+Z_i)K_{ihr} = w_h + o_h$ for technology h in zone r. Then, firm i retires technology h in region r if and only if $\sum_l \sum_s (c_{hrls} - (P_{rls} - b_{rls}(1+V_i)S_{irls}))v_s < -f_h - w_h$.

The first expression in Theorem 3 ensures that the capacity market recovers the fixed maintenance cost. The second expression sets the threshold for the retirement of technology h. Specifically, the sum of expected potential marginal operating losses and market power effects must be less than retirement costs f_h and sunk investment costs w_h. In an energy-only market, the threshold for the retirement of technology h is reduced to $f_h - o_h$, which accounts for its fixed operating costs.

When designing a capacity market, it is necessary to provide sufficient technologies to ensure a reliable electricity supply. The number of adequate technologies depends on market specifics. Theorem 4 shows that a generator can only recover a marginal plant's investment and fixed operation costs in an energy-only market if it can profitably withhold production. Furthermore, when there is also a capacity market, electricity production rises, and energy prices fall.

Theorem 4. Assume that there is no transmission between regions and consider an investment in marginal technology h in region r producing at full capacity. a) In the energy-only market, the generator's optimal sales are such that $E(P_{rls} - c_{hrls}) = E(b_{rls}(1+V_i)S_{irls}) + \frac{w_h + o_h}{L}$. b) Expected energy prices fall if a capacity market is introduced.

Designing a capacity market also requires determining which technologies to prioritize. Capacity markets may incentivize technologies to phase out carbon emissions when carbon prices are absent or insufficient. Moreover, as Theorem 5 states, creating a capacity market for technology h increases the marginal revenue the marginal investment receives. Thus, the introduction of a capacity market leads to higher investment.

Theorem 5. Introducing a capacity market for technology h in region r increases investment.

6. Case study: capacity expansion in the Saudi electricity market

This section analyzes the Saudi Arabian power sector's capacity expansion problem assuming that SEC's generation assets would be unbundled into four independent regional generators (G1, G2, G3, and G4). We build the MCP model described in Section 4 using the general algebraic modeling system (GAMS) and solve it using the PATH solver (Dirkse and Ferris, 1995).

Each generator makes investment and retirement decisions in Saudi Arabia's four primary grid regions. These regions are the Central, East, South, and Western Operating Areas (abbreviated COA, EOA, SOA, and WOA, respectively). The existing transmission infrastructure connects the regions. The COA-EOA, COA-WOA, and WOA-SOA lines have capacities of 5.2, 1.2, and 1.5 GW, respectively. These values are sourced from the KAPSARC Energy Model (KEM) Saudi Arabia for 2015 (Matar et al., 2017) under the assumption that no new interregional transmission capacity is built. Fig. 1 depicts the radial network.

Each generator operates three different existing technology types: open cycle gas turbine (OCGT), combined cycle gas turbine (CCGT), and steam turbine (ST) technology. The SEC's existing assets are distributed among the four new generators such that one owns a 27.1% share and the others each own 24.3%. This allocation does not represent any announced plans. It is chosen to reflect a market in which multiple players own and operate similar and differentiable technology mixes. The SEC's and other independent generators' ownership of the existing conventional generation capacity is shown in Table 2. These values are derived from the data in the annual report of the Electricity and Cogeneration Regulatory Authority (ECRA, 2019).

The generators can also invest in new units, including OCGT, CCGT, solar photovoltaic (PV), and wind power plants. For each technology, Table 3 lists the investment, retirement, fixed and non-fuel variable costs, and the heat rates expressed in million British thermal units (MMBtu) per MWh for oil and gas. These values reflect data provided by the SEC. Total operating cost coefficients used in the model combine the fuel and non-fuel components, using an assumed fuel price and heat rate of each technology and fuel mix. The liquid fuel supply (i.e., crude) is unlimited in each region. Natural gas is allocated regionally based on the reported levels of available gas for power generation in 2018 and projected to 2020 (no imports). The marginal cost of transmission is set to \$3.7/MWh for all interregional transmission lines based on Saudi National Grid data.

Hourly production by solar PV and wind is based on resource profiles from KEM Saudi Arabia (Matar et al., 2017). For each season and load block the renewables production is determined in Eq. (4.2) by multiplying the capacity variable K_{ihr} by the capacity factor (i.e., the averaged unrestricted output divided by the installed capacity) for solar and wind listed in Table C.1 and Table C.2, respectively (Appendix C). An additional constraint is added to the model requiring regional spinning reserves to operate at 20% of the current operating capacity of renewables. These act as a backup in case of outages. Only OCGT plants are used as spinning reserves and are configured to consume 10% of the fuel required when generating electricity. Spinning reserves are used as backup battery storage is not considered a viable economic option at the GW generation scale investigated. To avoid complicating the derivation of the analytical results we do not explicitly include these constraints in the generators' problem, equation block (4). The constraints are included in our numerical simulations adding an additional cost and minimal fuel consumption requirement for PV installments.

Power demand profiles are constructed for 2020 by rescaling regional load profiles from 2015 based on regional demand projections. We set expected demand growth for COA, EOA, SOA and WOA equal to 11%, 12%, 14% and 9%, respectively. Total demand in the wholesale energy market is forecast to be 409 TWh in 2020. The regional demand

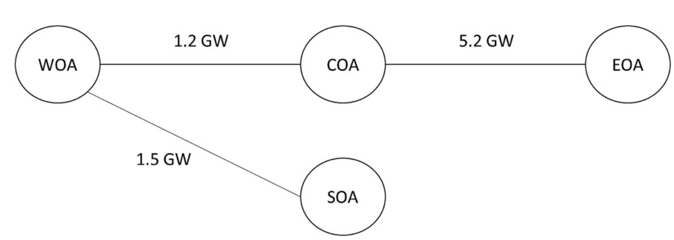

Fig. 1. Radial electricity transmission network of Saudi Arabia's four functional areas.

Table 2
Initial structure of capacity ownership by the SEC and other generators.

Capacity (GW)		CCGT	OCGT	ST	Total
Other independent generators	COA	0	1.42	2.4	**3.82**
	EOA	2.57	4.84	6.2	**13.61**
	SOA	0.00	0.00	2.43	**2.43**
	WOA	4.6	1.3	4.52	**10.42**
	Total	**7.17**	**7.56**	**15.55**	**30.27**
SEC	COA	3.08	9.56	0.01	12.65
	EOA	2.74	5.24	9.49	17.47
	SOA	0.00	1.49	2.64	4.13
	WOA	4.18	6.42	10.57	21.17
	Total	**9.99**	**22.71**	**22.71**	**55.41**
All firms	**Total**	**17.16**	**30.27**	**38.25**	**85.69**

profiles span eight demand segments (L1, L2, L3, L4, L5, L6, L7 and L8) and three seasons (summer, fall/spring and winter). The duration of each segment, and forecasted demand is shown in Table 4. Note the operating cost coefficients used in the model, c_{hrls} and φ_{nl}, are expressed in \$/KW, scaled to reflect the number of hours in each segment.

For each year we considered 7 different stochastic demand conditions (not shown) with probability ν_s capturing high and low variations across three standard deviations, based on SEC's hourly load profiles. The standard deviations are reported in Table C.3 in Appendix C.

Moreover, the inverse demand function, Eq. (1), is calibrated by calculating the coefficients using the generators' expected long-run marginal cost in each regional demand segment (D_{rls}) at current administered fuel prices. During baseload demand segments, the long-run marginal cost ($LRMC_{rls}$) equals the sum of a CCGT plant's variable operating and fixed costs (capital and operating) divided by the total number of hours. During peak demand segments, we derive the long-run marginal cost for peaking OCGT plants. The slope b_{rls} is set to reflect the estimated long-run price elasticity of demand (e_{rls}) in the wholesale electricity market: the long-run marginal cost divided by forecasted energy demand and the long-run price elasticity of demand: $b_{rls} = (LRMC_{rls})/(D_{rls}/e_{rls})$. We then determine the corresponding intercept $a = LRMC_{rls}\,(1 + 1/e_{rls})$.

Bigerna and Bollino (2015) develop a framework for estimating demand elasticities and present values in Italian wholesale electricity markets. These values range from −0.05 to −0.12. A liberalized wholesale power market has not yet been introduced in Saudi Arabia. Thus, the data needed to perform similar calculations for this market do not exist. Instead, we start by using a final demand elasticity of −0.16 derived from Saudi residential electricity consumer data by Atallah and Hunt (2016). The calibration process includes several iterations in which the regional slopes b_r are adjusted between +/− 9%, until the regional energy demand matches the forecast for 2020 in each load block l and scenario s. Because we do not account for transmission or distribution losses, the demand represents the generators' total energy production.

This calibration sets the condition of the business-as-usual (BAU) scenario replicating the expected demand under the current market structure. That is a market where the principal buyer organizes power purchase agreements with administered fuels prices of \$1.25 per mmbtu applied to all fuels (crude and natural gas) on an energy equivalent basis, and assuming no new capacity investments and no retirements. In the counterfactual scenarios described below, we analyze the transition to a wholesale market under different conditions, including demand response under the BAU demand curve. This includes firm behavior (competitive versus Cournot), fuel price reform, and the introduction of capacity markets with investments and retirements.

6.1. Capacity expansion with energy and transmission markets only

Here, we consider a restructured wholesale energy-only market with no capacity market. The competitive fringe is constrained to own and supply a maximum of 20% of the total capacity and energy, respectively, representing barriers to entry. These include limited access to capital for new firms, land rights, import permits for purchasing new equipment and other incentives favoring large generators' development. As mentioned earlier, these constraints allow us to solve the open-loop MCP as opposed to using a more complex EPEC as proposed by Devine and Siddiqui (2020).

We start by simulating two scenarios with fuel prices administered at BAU levels. First a case where firms operate in perfect competition ($V_i = -1$) and second where the four new firms form an oligopoly ($V_i = 0$): *competitive and Cournot energy market (current fuel prices),* respectively.

Table 3
Costs, expected lifetime, and heat rate of each technology.

Plant Type	Investment cost \$/KW	Retirement cost \$/KW	Lifetime years	Fixed cost \$/KW	Non-fuel variable cost \$/MWh	Heat rate MMBtu/MWh	
						Gas	Oil
OCGT	1016	152	25	11.2	4.6	11.37	12.63
CCGT	1102	165	30	12.4	3.76	6.82	7.26
ST	1026	154	35	11.2	1.87	9.22	9.75
PV	1153	–	25	9	–	–	–
Wind	1400	–	25	12.4	–	–	–

Table 4
Forecasted 2020 electricity demand in GW by region, season and demand block.

Units: GW	Hour Blocks	L1 0–4	L2 4–8	L3 8–12	L4 12–14	L5 14–17	L6 17–19	L7 19–21	L8 21–24
Region	Season								
COA	Winter	8.12	8.06	8.75	9.19	9.45	10.61	10.32	9.60
	Spring/Fall	13.19	11.91	13.41	14.62	14.89	14.84	14.59	14.10
	Summer	16.91	15.86	17.75	19.08	19.31	18.54	18.44	17.61
EOA	Winter	12.08	11.92	12.29	12.60	12.78	13.27	13.14	12.76
	Spring/Fall	15.72	14.97	15.92	16.66	16.60	16.73	16.64	16.36
	Summer	17.60	16.84	18.11	18.89	18.86	18.60	18.51	18.08
SOA	Winter	3.52	3.15	3.30	3.60	3.56	4.02	4.10	3.97
	Spring/Fall	4.37	3.84	4.26	4.68	4.56	4.59	4.84	4.75
	Summer	4.88	4.40	4.82	5.17	5.05	4.89	5.24	5.13
WOA	Winter	8.63	7.67	8.48	9.16	9.25	9.64	9.65	9.48
	Spring/Fall	13.05	11.73	13.02	14.12	14.14	13.63	13.81	13.68
	Summer	14.37	13.52	14.90	15.81	15.75	14.78	15.03	14.76

The same scenarios are run increasing fuel prices to \$3/mmbtu defined as our target reformed market, labeled as the *Competitive and Cournot energy market*. This raises the marginal production costs and the spark spread for efficient baseload units during peak demand periods, increasing operating revenues and encouraging a more efficient generation mix.

Finally, we run a *competitive energy market with oil price reform* scenario. The generators do not get any implied subsidies, with fuel prices set to international levels, calibrated to \$10/MMBtu or \$58 per barrel of oil. While a less likely outcome, this removes the inefficiencies caused by subsidies, and incentivizing investments in renewables. The capacity market scenarios described in the following section introduce incentives to encourage investments in solar PV technologies while maintaining prices at \$3/MMBtu. This supports Saudi Arabia's renewable energy targets while minimizing disruption (retirement) of existing conventional assets.

Table 5 summarizes the results of the BAU scenario, and the competitive and Cournot energy market scenarios with different fuel prices, including consumer surplus, fuel subsidies, total production and average electricity prices.

In Table 5, the consumer surplus measures the additional value that consumers obtain from electricity beyond the price they pay. Fuel subsidies are computed using the price-gap approach, the difference between the international price and the administered local price. Note that from the state's perspective, there is no subsidy on fuel expenditures, as administered fuel prices are higher than domestic production costs. We instead calculate the indirect or implied subsidy as the revenues foregone by the state-owned fuel supplier based on this internal pricing structure. The social surplus is defined as the sum of generator profits and the consumer surplus less implied fuel subsidies. The last column of Table 5 shows the average cost of electricity, which is the consumer price assuming that the utilities earn no rents.

The last scenario demonstrates that the most efficient solution from a social surplus perspective involves reforming fuel prices and promoting a competitive market. Thus, market mechanisms and private investment are optimal for ensuring that a reliable and efficiently priced electricity supply is provided. This scenario generates 18 GW and 10 GW of new solar PV and wind capacity, respectively.

We observe the distortion caused by fuel subsidies under the Cournot scenarios, with the exercise of market power decreasing the total subsidy amount and leading to a higher social surplus than the competitive market. When the generators exercise market power, production, fuel consumption, and thus implied fuel subsidies, decrease.

Note in the *competitive energy market* with *current fuel prices*, there is relatively little change with respect to the BAU. This suggests that at current fuel prices the market is near an optimal state, with slight improvements in the average cost of generation from investing in new capacity. Therefore, market reforms should include fuel price reforms to realize a higher social surplus. Fuel price reforms also increase generators revenues, and therefore the value of assets sold to the private sector by the state.

As expected, the Cournot energy market scenarios substantially increase the generators' profitability (irrespective of the fuel price reform) and, thus, the realized value of the SEC's existing assets that are sold to the private sector. However, the government may consider strategies to promote competition to prevent excessive firm profits post privatization while protecting the consumer surplus. The fuel price reform under a competitive market results in a more modest increase in profits. While the social surplus is lower in the competitive energy market scenario (versus Cournot), it is favorable when combining the outcomes of both the state and consumers. The reduction in implied fuel subsidies (\$9.1 billion) relative to the BAU scenario is enough to cover the reduction in consumer surplus, \$6.3 billion. By comparison, in the Cournot oligopoly, fuel subsidies decline by \$11.2 billion, while the consumer surplus declines by \$22.4 billion.

We also perform a sensitivity analysis on the allocation of existing assets by running scenarios with four regional monopolies, assigning the majority of baseload or peak generation capacity to a single large investor. This results in a marginal shift in the market equilibrium, with prices changing $<1\%$ on average. The distribution of assets among generators is more heterogeneous in this scenario, with the larger investors developing capacity in their respective regions.

6.2. Capacity payments and auctions

We next introduce capacity market scenarios to the Cournot energy market, considering both fixed capacity payments and a capacity auction. We use these results to illustrate the earlier theoretical results (Theorems 3 and 5) on using capacity market design to influence the investment (and retirement) balances for different technologies. The state could use this strategy, implemented by the principal buyer, to support the development of available capacity (reserves) and expansion policies in Saudi Arabia. For example, this strategy could support the government's renewable investment objectives. We also investigate the capacity market's impact on prices in the energy market (Theorem 4) and the implications for consumers.

First, we run a scenario with fixed capacity payments for all technologies (Capacity payment). In this case the regional capacity prices are set to a fraction of the CCGT's annualized fixed cost (capital and maintenance). The regional fractions are derived from the results of the Cournot energy market, as the ratio of hours in each region when the realized peak energy demand (the highest stochastic demand scenario) exceeds 80% of the capacity made available by all generators. The ratios used to set the regional capacity prices are 66%, 3%, 46%, and 7% in the COA, EOA, SOA and WOA, respectively. These results depict how the COA and SOA more prone to capacity constraints purchasing the most power from neighboring regions driving up electricity prices nationally. Therefore, higher capacity prices in these regions can help prevent firms from creating regional shortages that drive up prices.

We run an additional capacity market scenario that includes a fixed payment only for renewables (Renewables capacity payment). In this scenario, the capacity price is differentiated not only by market segment m but also by technology h. This covers a percentage of the renewable plants fixed costs (capital and maintenance), shown in Table 3. With an

Table 5
Profits, Consumer Surplus and Social Surplus (billion \$).

Scenario	Firm profits	Consumer surplus	Fuel subsidy	Social surplus	Supply (TWh)	Average price (\$/MWh)	Average cost (\$/MWh)
BAU	0.55	77.90	19.01	59.43	404	18.3	14.4
Competitive energy market (current fuel prices)	0.64	77.82	19.01	59.64	404	18.4	14.3
Competitive energy market	0.90	71.58	9.87	62.61	369	34.4	29.4
Cournot energy market (current fuel prices)	16.82	60.00	14.29	62.54	337	56.1	14.1
Cournot energy market	15.41	55.55	7.19	63.77	315	81.0	29.2
Competitive energy market with oil price reform	3.57	63.47	–	67.04	341	55.3	38.5

administered fuel price of \$3/MMBtu, PV and wind investments require a capacity payment above around 35% of the fixed costs. Given the higher costs of wind versus solar, and to encourage a balanced investment in both, we apply a capacity price equal to 60% and 50% of the fixed costs of wind and solar, respectively.

Table 6 compares the profits, consumer surplus, social surplus, supply, and average unit price paid to the firms (including capacity payments), from the original Cournot energy market to the two capacity market scenarios. Capacity payments are included in the firms' profits but are subtracted from the social surplus. Relative to the baseline Cournot energy market, capacity payments lead to increases in profits, the consumer surplus, and total electricity demand and production. In the Renewable capacity payment scenario, firm profits are marginally lower because of lower average and maximum energy prices. This decrease is caused the addition of PV production that substitutes OCGT plants during the midday peak at a lower marginal production cost (see Fig. 2). Wind also contributes to lowering the marginal production cost, but also operates at night during some load segment and seasons. Both scenarios lead to higher consumer surplus.

The Capacity payment scenario results in a small social surplus decline, as either consumers or the government must cover the additional capacity market cost for all existing conventional technologies. However, in the case of Renewables capacity payment this cost is more than covered by the reduction in fuel subsidies with conventional fuels displaced from the generation mix. As a result, the social surplus increases by \$1 billion relative to the Cournot energy market and results in a lower fixed capacity payment by targeting only renewable investments. The capacity payment scheme clearly can help attract new renewable investments while displacing energy subsidies, marginally improving consumer surplus and social surplus in an oligopolistic market.

Fig. 2 illustrates the available capacity by technology in our five scenarios. When higher fuel prices are applied in the Cournot energy market scenario, investors' technology choices shift to more efficient CCGTs. Around 18.6 GW of OCGT plants are retired with 5.2 GW of new efficient CCGT plants. This occurs as regional oligopolies reorganize their baseload and peak capacities to maximize profits.

The capacity payment scenarios show that the principal buyer's actions can influence the investors' optimal strategies. The existing OCGT capacity that the SEC sells to the private sector is preserved. This avoids efforts by oligopolies to create scarcity in peak generation capacity and helps to reduce average and peak energy prices (Table 6). The capacity market also contributes to maintaining regional reserve requirements, measured as the percentage of regional dispatchable capacity exceeding the expected regional peak power demand. Without a capacity payment, reserves fall well below 10% in the COA and SOA. In high demand scenarios reserves are found to fall into the negative relying heavily on transmission from the neighboring EOA and WOA. However, in the Capacity payment scenario reserves are always positive. Therefore, in the absence of a capacity market, the Cournot energy market may face higher regional reliability and outage concerns, with potential system costs not accounted for in the current model.

It follows from Theorem 3 that plant retirements are postponed when either the cost of retirement or the cost of investment in new capacity increase. They are also postponed when marginal production costs decrease, as, for example, through a subsidy.

As in the competitive energy market with the oil price reform scenario, the Renewable capacity market scenario incentivizes the development of new solar and PV capacity, 25 GW and 9 GW, respectively. However, this scenario does not comprehensively reform energy prices. As shown in the Competitive energy market: oil price reform scenario, such reforms lead to the retirement of existing assets, such as OCGT and ST capacity (Fig. 2).

6.3. TSO's role in a capacity market

Thus far, we have presented a national overview of capacity markets' impacts. However, we have not yet addressed the roles of the TSO and regional transmission services under different market structures. Fig. 3 depicts the expected zonal energy prices, difference in zonal POOLCO prices, and total transmission in the Cournot energy market and capacity payment scenarios in panels (a), (b), and (c), respectively. The figure shows the values for each grid region during the midday demand peak from noon to 2 p.m., segment L4 from Table 4.

As expected, power flows from regions with lower prices (e.g., EOA and WOA) to regions with higher prices (e.g., COA and SOA) when capacity is available. Note that the differences in energy prices across connected regions in (Fig. 3a) match the differences in POOLCO prices shown in Fig. 3b for each scenario, satisfying the requirement of the no-arbitrage condition in Eq. (7.7). Capacity markets tend to reduce regional differences in energy prices. The WOA-SOA link is the exception where price differentials increase under the Renewables capacity payment scenario. This is because the WOA invests in additional wind generation capacity with a lower production factor during the midday demand peak, increasing transmission from the SOA.

Generators' efforts to withhold capacity and increase prices in regional energy markets through shortages during peak demand periods are less effective with capacity markets. This exciting result has an explanation. It follows from Theorems 4 and 5 that capacity markets reduce energy prices and increase investments in capacity. The resulting additional production capacity, distributed among the regions, decreases the transmission needs, energy, and transmission prices.

6.4. Renewables capacity auction

From a societal perspective, capacity payments for PV can encourage renewable investments when incentives, like administered prices, exist for fuels used by conventional generation capacity. However, capacity payments represent a high fixed cost that must be paid either as a subsidy from the government or by consumers. Discounting indirect fuel subsidy savings from reduced consumption of oil, which are not direct payments by the state, these transfer payments organized by the principal buyer between the generators, final consumers, and government accounts impose a real societal cost.

An auction may be more suitable for managing capacity prices as a function of the quantity of capacity built to incentivize large renewable investments. We, therefore, introduce a Renewables capacity auction scenario designed to gradually increase investment in solar PV and wind, following Theorem 5, while ensuring that the price declines as a function of the total capacity submitted. The intercept of Eq. (2) θ_{hr} is set

Table 6
Profits, consumer surplus and social surplus (billion \$).

Scenario	Firm profits	Consumer surplus	Fuel subsidy	Capacity payment	Social surplus	Supply (TWh)	Average price (summer max) (\$/MWh)
Cournot energy market	15.41	55.55	7.19	–	63.77	315	81.0 (207.6)
Capacity payment	16.4	56.49	7.77	1.96	63.15	319	79.1 (191.9)
Renewables capacity payment	15.02	56.21	4.49	1.91	64.83	316	79.0 (188.9)

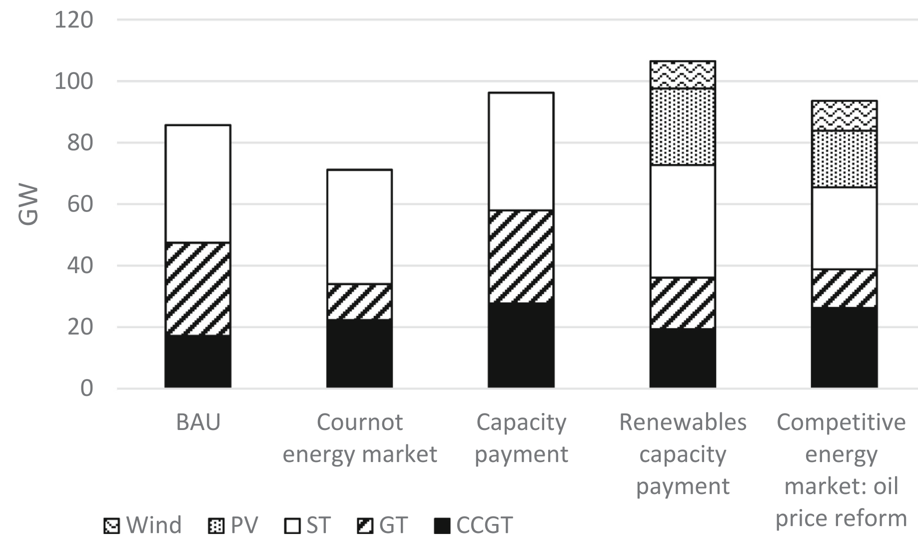

Fig. 2. Available capacity (GW) per technology in different scenarios.

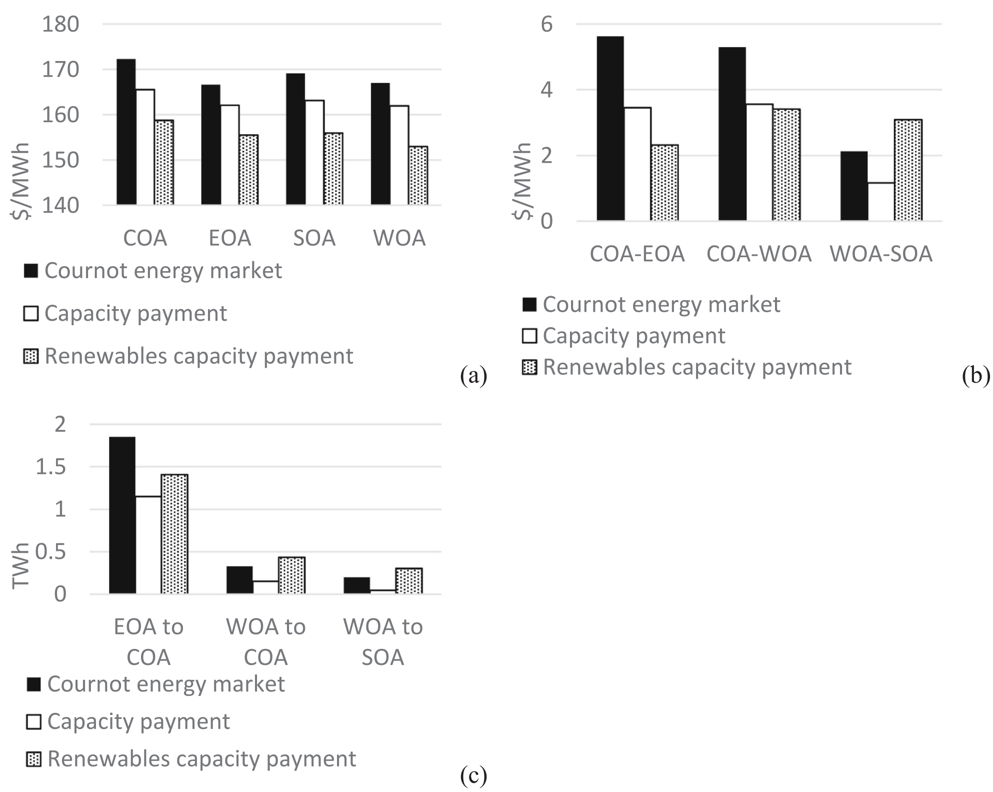

Fig. 3. Regional energy prices (a), transmission or POOLCO prices (b), and total power transmission (c) in the Cournot energy market and Capacity payment scenarios during peak midday demand.

to double the capacity prices specified in the capacity payment scenario (i.e., 50% and 60% of the fixed costs of solar and wind, respectively). The slope of Eq. (2) is defined for a selected capacity target in each region $\left(C^*_{hr}\right)$ when the price equals the targeted portion of the fixed cost, e.g., $\xi_{hr} = 0.5\,\theta_{hr}/C^*_{hr}$, for $h = PV$.

We assume the regional renewable capacity targets shown in Table 7, reflecting values set under Saudi Arabi's 2030 vision, i.e., 40 GW PV and 16 GW wind (note that Saudi Arabia's updated target is that renewables form 50% of the total power generation capacity in 2030). They provide a balanced distribution with wind concentrated in the Western and Southern regions where annual capacity factors are higher (Table C.2).

Table 7
Targeted renewables capacity in the auction (GW).

	COA	EOA	SOA	WOA
PV	15	5	5	15
Wind	14	0	2	0

We analyze the sensitivity of energy and capacity prices to changes in the regional PV capacity targets in the Capacity auction PV scenario. Fig. 4 compares the equilibrium prices in the COA by changing the regional renewable targets in increments of 20% until it reaches 200% of

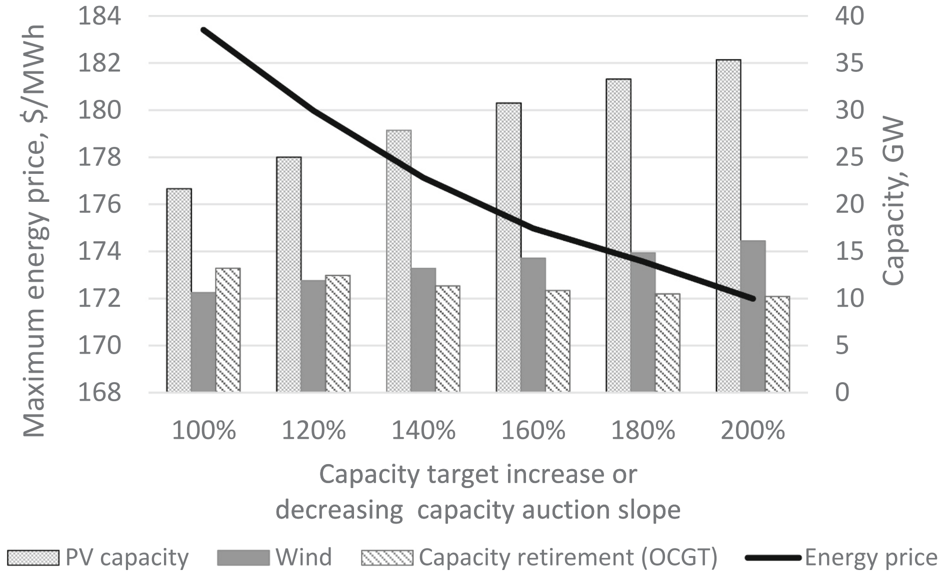

Fig. 4. Capacity auction sensitivity analysis for the COA.

the values in Table 7. Fig. 4 shows the increase in total PV and wind capacity and reduction in OCGT retirements as the spinning reserve requirements increase.

Corollary 2 predicts that decreasing the capacity auction's slope (increasing the target) should reduce the maximum energy market prices by incentivizing more investment (higher target) in renewable capacity. A lower slope implies that additional capacity can be added to the system at a higher price. In a capacity-constrained market, decreasing the capacity auction's slope increases capacity through new investments (or offsetting retirements).

We observe a trade-off between capacity and energy prices. When the capacity target doubles, the maximum energy price declines by 7% while capacity prices increase by about 14%, incentivizing an additional investment of 13.5 GW in total PV capacity, and an additional 3.5 GW of wind.

Another challenge with the PV capacity market scenarios is distortions in the regional reserve margins. Focusing the capacity market on renewable investments can contribute to declining dispatchable reserves (OGCT and CCGT combined), that can lead to regional shortages during peak demand hours in the COA and SOA. As in the Cournot energy market, reserves are negative in some regions, falling as low as −36% in the COA during the Capacity auction PV sensitivity analysis. Therefore, in designing a capacity market to incentivize renewable investments, the principal buyer should consider how this will impact the availability of dispatchable OCGT units to ensure adequate regional reserves.

7. Conclusions

We analyzed the capacity expansion problem in a liberalized electricity market with an oligopolistic market structure. We consider a stochastic demand pattern, fixed and variable generation costs, and several alternative generation technologies. We account for the interactions between the energy market and the capacity market in a mathematical model with zonal pricing for the generators' production and investment decisions and the trade of energy between zones organized by a TSO. We used this model to compute the Nash equilibrium of a Cournot oligopoly with a competitive fringe.

After deriving theoretical implications from the combination of energy and capacity markets, we applied the mathematical model to study possible market reforms of Saudi Arabia's electricity sector. Our results are based on a detailed calibration of demand, transmission, generation, and investment costs.

Our analysis shows that new generators benefit from owning a diversified portfolio of peak and baseload plants. Buyers of existing capacity benefit if a capacity market is introduced soon after privatization. This timing allows them to capture a more significant share of the rents created by the new market structure.

Our study demonstrates several benefits of privatizing the electricity industry with capacity auctions (or payments). Doing so increases supply reliability during peak demand periods, creates more significant investments in and less retirement of existing technologies, and, crucially, increases the value of existing generation capacity. Additionally, capacity payments lead to lower energy prices and more significant investments, and reduce differences in regional POOLCO prices. This result suggests that the Saudi government might consider designing and implementing a capacity market before fully privatizing state-owned generation assets. Following privatization, regional capacity payments can be used to encourage investment in renewable capacity by the private sector to achieve government targets.

We illustrate how a renewable capacity market in a Cournot oligopoly can help increase investment and improve consumer and social surpluses. The additional fixed costs of wholesale electricity are more than offset by the reduction in inefficient implied fuel subsidies. This way, a capacity market can improve market efficiency and renewable investments while maintaining competitive fuel prices for conventional technologies. Moreover, introducing a capacity market for renewable energy (solar and wind) supports the retirement of carbon-emitting technologies, such as OCGT and ST technologies, and can help reduce the country's CO_2 emissions.

Our numerical analysis also shows that reforming industrial fuel prices before restructuring Saudi Arabia's electricity industry can increase the value of existing assets. Prospective new entrants may benefit from buying assets if they receive a guarantee that the fuel price reform will be implemented after the electricity industry is privatized. Additionally, the market regulator and the SEC need to consider the potential effects of non-competitive behavior on energy prices. Such behavior can have an even more pronounced impact on the value of existing assets sold to the private sector.

Finally, we study how a capacity market can address declining capacity reserve and system reliability in regions affected by neighboring markets. Without a capacity market, negative reserve margins can emerge, increasing the risk of system outages, and costs not accounted for in our social surplus calculation. While capacity payments or auctions for renewables can shift production away from thermal technologies and reduce fuel subsidies, this can further reduce reserve margins. The principal buyer(s) should consider this when designing a capacity auction. New entrants' investment strategies should consider regional capacity auctions and their abilities to negotiate the rules of any such auctions with the principal buyer(s).

Credit author statement

Fernando Oliveira has collaborated in conceptualization; writing - original draft; methodology, review & editing; formal analysis; supervision.

Bertrand Rioux has collaborated in conceptualization; validation; software; methodology; writing - original draft.

Axel Pierru has contributed to conceptualization; writing - original draft.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2023.106958.

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