Capacity and Energy-Only Markets under High Renewable Penetration

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***Abstract*—This paper presents a multi-nodal intertemporal Cournot gaming model with transmission constraints and uses it to simulate energy-only and capacity-energy market designs in the presence of uncertainties stemming from intermittent renewable power generation. Both market paradigms are compared to a competitive benchmark in order to determine which one performs better in a concentrated market with significant penetration of wind and solar generation. As a specific example, the model is applied to the South Australian zone of the Australian National Electricity Market (NEM). The simulation results for the time interval 2013-2030 show that the capacity-energy market has the potential to induce significant new capacity and push prices much closer to the competitive level in contrast to the current energy-only market design.**

***Index Terms*—Cournot game, Inter-temporal optimization, Wind power variability, Australian electricity market.**

I. Introduction

Electricity markets can be classified into two dominant types: energy only markets (EOMs) such as those currently operating in Australia, New Zealand and Singapore, and capacity-energy markets (CEMs) which make a separate payment for capacity availability in addition to actual electricity generation. Both forms of electricity markets have become more sophisticated over time with co-optimized markets for ancillary services, close-to-real-time operation and management of transmission constraints. The very first electricity markets in Chile and the England and Wales power pool during 1980s and early 1990s, which can be labeled as the "first generation" markets, have been followed by the "second generation" more sophisticated markets since the mid to late 1990s throughout the world.

Recent investments in renewable energy and emphasis on carbon abatement have resulted in massive volumes of wind, followed by solar photo-voltaic (PV) generation, which create new challenges for power system operators. The technical challenges due to extreme variability in supply is already a subject of intense research.

High penetration of renewables also raise difficult questions for market design proponents since most of the existing "electricity" markets today were established before the advent of large-scale intermittent renewable power generation. Design of an "ideal" market has been the subject of heated debates as the one on the Electric Reliability Council of Texas (ERCOT) market design demonstrates [1]. One of the key objectives of this paper is to compare and contrast performance of EOM and CEM design under higher renewable penetration in terms of price and new entry outcomes.

TABLE I
THE VARIABLES USED IN THE COURNOT GAME MODEL

Variable	Description
i	generation company (genco) $i \in \mathcal{N} = \{1, \dots, N\}$
j	geographical nodes where gencos operate, $j \in \mathcal{M} = \{1, \dots, M\}$
y	a fixed interval, e.g. months/quarters/years $1, \dots, Y$
t	sub-periods within y e.g., blocks of hours for a load duration curve
$q_i^c(y)$	incremental capacity investment decision of genco i in year y
$q_i^e(y,t)$	electricity generation decision of genco i in year y and time period t
$P_{e,j}(y,t)$	per-unit electricity price at node j in year t and time period t
$P_{c,j}(y,t)$	per-unit capacity price/payment at node j in year t and time period t
$X_{i,j}^e(y,t)$	generation of a genco i at node j in year y and time period t
$Y_{i,j}^c(y)$	total generation capacity of genco i at node j in year y
$X_{i,j}^c(y)$	incremental capacity investment of genco i at node j in year y
$Y_j^e(y,t)$	total energy available at node j in year y and time period t
$F_{j',j}^e(y,t)$	physical energy flow from a node j' to node j in year y and time period t
$F_{j',j}^{max}$	transmission constraint a node j' to node j in year y

It should be noted that the emphasis in the analysis is to study the nature of equilibrium outcomes that are likely to emerge under these two alternative market designs. All other things being equal in the short term, conventional large gencos who may possess market power would be inclined to bid aggressively during periods of low wind availability, in part because off-peak prices tend to be depressed (including negative prices as we have discussed later). The volatility in an EOM is expected and is part and parcel of the design to induce new investment. The issue we explore in particular is whether high penetration of renewables in a concentrated market increases it to a point where it starts denting market efficiency considerably. While increased price volatility with significant wind penetration includes upside opportunities for new entrants, it also includes significant downside (low price) risks for price-taker new entrants. The CEM design in principle

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has some of the answers because it includes a capacity payment to incentivize new entrants and to dampen the need for incumbent large generators to bid too aggressively. The design therefore may in theory yield more orderly investment leading to lower price volatility, albeit may include the prospect of over-investment depending on the joint equilibrium outcome in capacity and energy markets.

A. Overview of Literature

Intermittency of wind and solar PV without adequate hydro or some other form of storage may cause significant swings in generation that can be far in excess of the ones accounted for in the traditional (N-1) security standard. Such variability in generation may cause major frequency excursions and may push the power system closer to the point of voltage collapse. There are multiple strategies for countering the effects of intermittency. Better and more coordinated operation of existing generation assets is one solution, yet this may not be sufficient in some scenarios. Then, the system needs to carry spinning reserve (including some form of storage, peaking gas/hydro generators or demand response), which in many systems can exceed the level needed to meet the outage of the largest generating unit. These novel spinning reserve requirements have significant implications for power system planning, operation and control as has been succinctly summarized by Perez-Arriaga [2] as well as investigated by [3], [4]. Lew et al [4] have discussed some of the recent advancements to add flexibility to a power system and how these resources can be optimized.

Achieving the necessary flexibility in generation requires additional investment which can only happen if the market design has targeted instruments to put a value on such flexibility [5]. Mitigating the impact of intermittency in generation requires efficient dispatch of flexible resources such as hydro and battery battery storage as well as demand side management in order to ensure that minimal ramping is needed from the more inflexible sources in the generation pool. In any case, some adjustments to the dispatch are inevitably needed bringing additional costs to the system. The estimates of these costs vary a great deal depending on the system characteristics but also the modelling methodology employed. Holttinen et al [6] from National Renewable Energy Laboratory (NREL) have recently reported results from an extensive case study for the USA showing that the cost of intermittency can be quite low, and adds only a small fraction of a cent per kWh to the overall cost of generation, e.g. 0.1-0.2 c/kWh.

Chao and Huntington [7] have compiled research findings and lessons from electricity market design during the early to mid-nineties. They highlight major differences in opinions on how markets should be structured, which experiments have been conducted with capacity and energy markets around the world, and regulatory reforms and experience with pricing and investment outcomes during the initial years of operation. Some of the debated issues include the need for a capacity market over and above an energy market, which arises because an EOM in itself does not necessarily attract sufficient generation capacity to meet the desired reliability standards.

Generation capacity has often been an issue in hydro-dominated systems prior to the days of large-scale intermittent generation where the risk of a low-probability but high-cost event such as once-in-a-ten-year drought cannot necessarily be mitigated even with a fully efficient EOM. These debates continue to date. For example, as part of the latest debate on ERCOT design, Pfifenberger et al [8] have recently noted that while EOM can deliver an economically optimal level reserve margin, maintaining a reliability standard against once-in-a-ten-year events necessitates a CEM. This conclusion echoes a number of theoretical analyses conducted over the years including the following opinion [9] of Professor Paul Joskow from MIT, who states: “numerous analyses of the performance of organized energy-only wholesale markets indicate that they do not appear to produce enough net revenues to support investment in new generating capacity in the right places and consistent with the *administrative reliability criteria* that are still applicable in each region.”

Wolak has reported similar findings in the context of Latin American wholesale electricity design [10]. Large scale penetration of intermittent renewable generation in a thermal market raises a reliability issue similar to the one in a hydro-dominated system. However, the reliability issues in this case are not merely inter-annual but may occur at hourly, daily and seasonal timescales.

In addition, market power has emerged as a significant issue in both CEM and EOM markets as reported in a compilation of market power modelling studies in [11]. As will be discussed in the next section, market power has been a significant problem in Australia as well as in many other markets [7]–[10]. It was one of the key factors that contributed to the modification of the England and Wales markets’ initial pool designs [12].

Market design issues have also been debated in the European Union (EU) with a range of arguments for and against EOM and CEM. On the one hand, the lack of adequate coverage of system reliability in an EOM has been strengthened with the proliferation of intermittent renewables in the recent years. On the other hand, the reverse problem of over-investment in the type of generation in a CEM that is not flexible enough to cope with intermittency has also been an issue [13]. The major trend in EU however has been in favour of a capacity market. Finland, Greece, Ireland and Northern Ireland, Italy, Portugal, Spain and Sweden have already implemented some form of capacity market although the precise design of these markets show significant variation. CEMs have also been introduced in Belgium, Denmark, France, Germany and Great Britain [14].

B. Contributions and Organization

This paper examines the efficacy of energy-only (EOM) and capacity and energy markets (CEM) using a Cournot game model [15]–[18] and investigates the South Australia zone of the National Electricity Market (NEM) as an illustrative case study. Both market paradigms are compared with a competitive benchmark to evaluate which one performs better than the other in the highly concentrated South Australian zone of the National Electricity Market (NEM) of Australia which has a significant penetration of wind/solar generation. The Cournot game models are simulated over the years 2013-2030 to examine if one paradigm performs better than the other in inducing new capacity investments and bringing prices closer to the competitive level in the long term.

The rest of the paper is organized as follows. The next section discusses and analyzes various issues in EOMs with an emphasis on Australian NEM. Section III describes the analytical underpinnings of the Cournot (strategic) game model used both for energy-only and capacity-energy market analysis. Section IV presents extensive simulations of the South Australian zone of the NEM with real data and projections obtained from the AEMO's National Transmission Network Development Plan (NTNDP) [19]. The analysis presented here pays particular attention to uncertainties associated with intermittent wind generation. Low wind conditions during peak demand periods in South Australia have caused significant market power issues in the past [21]. Therefore, this study specifically explores whether higher penetration of wind going forward would require a change in the market design away from an EOM regime to maintain a reasonable investment and dispatch efficiency close to the economic optimal. The paper concludes with a discussion and remarks in Section V.

II. Energy-only Markets and Australian NEM

In an EOM market, the energy spot market plays a central role, and governs not only the exposed part of a generator/retailer portfolio, but also has a direct influence on the contract prices. The volatility in spot prices in an EOM market arises from continuous fluctuations in supply-demand balance. The volatility in a system such as NEM with a very modest amount of hydro and storage can be extreme with wholesale prices jumping from below 5 c/kWh to Australian Dollar (AUD)13.10/kWh in a matter of five minutes.

In South Australia, which is part of the NEM, high level of wind generation accounts for 27% of the market share, which (a) corresponds to a significant share of the market, and (b) depresses prices during high periods of wind (during off-peak) to a very low level with the bottom 500 hour prices in a price duration curve averaging (-)AUD 7/MWh.

In addition to price volatility, there has been ongoing political uncertainties in Australia over the last five to six years regarding energy policies. Consequently, there has been a trend of vertical integration wherein the large retailers have acquired generation assets often at strategic locations to form a flexible portfolio of low capex open cycle gas turbines (OCGT) and renewables, to manage policy as well as price volatility risks. In fact, a significant part of the NEM today has virtually been reduced to just three such vertically integrated players.

There are clear signs that a highly concentrated market such as South Australia is prone to abuse of market power [20]. Our recent analysis [20] that combines a game-theoretic analysis together with wind variability, for instance, simulates South Australian spot prices using a Cournot gaming model. When we compare these prices with a perfectly competitive benchmark, the prices at the high end (top 100 hours) is significantly higher by AUD 172/MWh compared to competitive prices and the shoulder period is also more than AUD 50/MWh higher. These price differences are strong indications that prices during shoulder/peak when contribution from wind are typically low, are susceptible to use of market power in a concentrated market. Since wind generators and generally any new baseload entrant that is not part of incumbent existing dominant gencos do not necessarily benefit from the higher peak/shoulder prices, the current EOM design poses a significant challenge for investment leading to a flexible generation mix that supports high renewable penetration.

III. Cournot Game Model

As the first step of our analysis, we define a generic Cournot (strategic or noncooperative) game to model the decisions and incentives of a set of generation companies or gencos, $\mathcal{N} = \{1, \dots, N\}$, actively participating in an electricity market. In the game defined, gencos decide on their power generation and incremental capacity investments at fixed time intervals. Specifically, each genco $i \in \mathcal{N}$ makes an incremental capacity investment $q_i^c(y)$ resulting in the generation capacity $Y_i^c(y) = \sum_{\tau=1}^{y-1} q_i^c(\tau)$ for $y = 1, \dots, Y$. These investments are over a set of geographically dispersed nodes $j \in \mathcal{M} = \{1, \dots, M\}$ such that $Y_i^c(y) = \sum_j Y_{i,j}^c(y)$. Each time period $[y, y+1)$, is further divided into fixed intervals, which may represent weeks, months, or quarters, denoted by $t = 1, \dots, t_M$. The genco i decides on how much electricity to generate $q_i^e(y,t) \le Y_i^c(y)$ at each time interval $[(y,t),(y,t+1))$. Consequently, the decision vector of each player (genco) i is

$$q_i := [q_i^c;\ q_i^e]^T \in \Omega := [0, q_{max}]^{Y + Y t_M},$$

where $[\cdot]^T$ represents the transpose operation, $q_i^c(y) = [q_i^c(1), \dots, q_i^c(Y)]$, $q_i^e = [q_i^e(1,1), \dots, q_i^e(Y, t_M)]$, and the parameter $q_{max} > 0$ is a scalar upper-bound on each element of q_i. Note that, the decision space Ω is compact and convex. Furthermore, the investment and operational decisions of gencos are captured in two separate but interleaved time scales. A list of all variables used in this paper is provided in Table I. The following three sub-sections are organized as follows: (a) Section III(A) provides an initial exposition to the EOM market analysis including the key properties of a Cournot Nash equilibrium in this setting; (b) Section III(B) then introduces the capacity decisions and payments to extend the discussion; and (c) finally, Section III(C) presents the complete model with all constraints that we have used for the analysis.

A. Energy-Only Market Model

In an energy-only market, gencos' (including renewable generator) revenue solely come from power generation and sales. The incentives of the gencos are formulated using a linear production cost and revenue model as a first order approximation and to ensure theoretical and computational tractability. The quasi-linear model is commonly used in the literature [15], [18], [20]–[23].

The incentives of gencos are next modeled using quasi-linear utility functions such that the utility function of the genco i is

$$\begin{aligned} U_i^e(q) = & \sum_{y=1}^{Y}\sum_{t=1}^{t_M}\{q_i^e(y,t)P_e(y,t) - c_i^e q_i^e(y,t)\} \\ & -\sum_{y=1}^{Y} c_i^c q_i^c(y) - \epsilon\sum_{y=1}^{Y}(q_i^c)^2(y), \end{aligned} \tag{1}$$

where ϵ is a small positive scalar introduced to ensure strict concavity of the utility function. The constants c_i^c and c_i^e quantify the per unit capacity investment and power generation costs, of genco $i \in \mathcal{N}$, respectively. Hence, its total capital expense (capex) is $\sum_{y=1}^{Y} c_i^c q_i^c(y)$ and total operational expenses (opex, marginal generation cost) is $\sum_{y=1}^{Y}\sum_{t=1}^{t_M} c_i^e q_i^e(y,t)$. The players strategies are affected by the per-unit prices, $P_e(y,t)$ and $P_c(y)$, which depend on the aggregate electricity production and demand in the market. The linear per-unit pricing function

$$P_e(y,t) := \alpha(y,t) - \beta(y,t)\sum_i q_i^e(y,t) \geq 0, \tag{2}$$

is determined by the market demand for electricity [18] and $\alpha(y,t)$, $\beta(y,t)$ are inverse demand equation parameters.

Lemma 1. *The genco utility function (1) is concave in q_i.*

Proof. For any $\epsilon > 0$ and assuming α, β, c_i^c, $c_i^e > 0$, the Hessian of the utility function (1) is negative definite which ensures concavity [24]. $\square$

Given the aggregate demand and decisions of other gencos, each genco i solves the following profit maximization problem:

$$\max_{q_i \in \Omega} U_i^e(q) \text{ s.t. } A(y,t)q(y,t) \leq b(y,t),\ \forall t, y \tag{3}$$

where $q = [q_1; \ldots; q_N]^T$ and the matrix inequality $A(y,t)q(y,t) \leq b(y,t)$ represents the generation constraints at time period (y,t) including the capacity constraints

$$q_i^e(y,t) \leq Y_i^c(y),\ \forall t, y. \tag{4}$$

The convex optimization problem (3) admits a unique solution, which immediately leads to the following result.

Proposition 2. *The electricity generation strategic (noncooperative) game $\mathcal{G}^e = \{\mathcal{N}, q \in \mathcal{Q}^e, U^e\}$ admits a Nash equilibrium solution, q^*, if the player strategy space $\mathcal{Q}^e := \{q \in \Omega^N | A(y,t)q(y,t) \leq b(y,t),\ \forall t, y\}$ is compact, convex, and non-empty.*

Proof. The proof is provided in the Appendix. $\square$

B. Capacity and Energy Market Model

In a capacity and energy market, the genco i (including renewable generaor) receives revenue for not only generating power but also making a capacity investment. Both energy spot price and capacity payments are made to all generators including renewable generators. Hence, the utility function of a genco i differs from (1) and is defined as

$$\begin{aligned} U_i^{ce}(q) = & \sum_{y=1}^{Y}\sum_{t=1}^{t_M}\{q_i^e(y,t)P_e(y,t) - c_i^e q_i^e(y,t)\} \\ & +\sum_{y=1}^{Y}\{q_i^c(y)P_c(q,y) - c_i^c q_i^c(y)\}, \end{aligned} \tag{5}$$

where the linear per-unit pricing function for capacity

$$P_c(y) := \bar{\alpha}(y) - \bar{\beta}(y)\sum_i q_i^c(y) \geq 0, \tag{6}$$

is determined by the market demand for capacity and $\bar{\alpha}(y)$, $\bar{\beta}(y)$ are the inverse demand equation parameters.

Lemma 3. *The genco utility function (5) in a capacity and energy market is concave in q_i.*

Proof. Assuming α, β, $\bar{\alpha}$, $\bar{\beta}$, c_i^c, $c_i^e > 0$, the Hessian of the utility function (5) is negative definite which ensures concavity [24]. $\square$

Consequently, each genco i solves the following convex profit maximization problem:

$$\max_{q_i \in \Omega} U_i^{ce}(q) \text{ s.t. } A(y,t)q(y,t) \leq b(y,t),\ \forall t, y, \tag{7}$$

which admits a unique solution similar to (3). The counterpart of the result in Theorem 2 follows accordingly.

Proposition 4. *The electricity generation strategic (noncooperative) game modeling the decisions and incentives of gencos in a capacity and energy market, $\mathcal{G}^{ce} = \{\mathcal{N}, q \in \mathcal{Q}^e, U^{ce}\}$, admits a Nash equilibrium solution, $\bar{q}^*$, if the player strategy space $\mathcal{Q}^e := \{q \in \Omega^N | A(y,t)q(y,t) \leq b(y,t),\ \forall t, y\}$ is compact, convex, and non-empty.*

Proof. The proof is similar to that of the Theorem 2. $\square$

The main difference between the game modeling capacity and energy market, $\mathcal{G}^{ce}$, and the energy-only market game, $\mathcal{G}^e$, is the revenue term $\sum_{y=1}^{Y} q_i^c(y)P_c(q,y)$ in (5).

C. Multi-Nodal Model with Transmission Constraints

The game model is extended to take into account the transmission constraints and multi-nodal generation at different geographical locations. Transmission flow limits just like generation capacity limit is a physical constraint that should be recognized because it can impact on the equilibrium quantities in the Cournot equilibrium. Transmission constraints will not necessarily affect all generators equally and to that extent it might give a strategic advantage to one generator more than others, e.g., a local generator in a constrained load pocket may have significant market power over others [25]. Generation from (dispatchable) generators is considered controllable and to the extent transmission constraints affect generation is incorporated in the Nash equilibrium analysis. For example, a local generator possessing market power in the constrained part of the network can strategically withdraw generation to produce less than what a least-cost dispatch might otherwise dictate.

Let $X^e_{i,j}(y,t)$ be the generation of a genco i at node j at year y and period t. Then, the total generation of a genco i is $q^e_i(y,t) = \sum_{j=1}^{M} X^e_{i,j}(y,t)$. The generation of a genco i at node j is bounded above by its capacity at that node $X^e_{i,j}(y,t) \le Y^c_{i,j}(y) \le q^c_i(y)\ \forall y,t$, where the current capacity is the sum of capacity investments in previous years: $Y^c_{i,j}(y) = \sum_{\tau=1}^{y-1} X^c_{i,j}(\tau)$.

The physical energy flow from a node j to another node j' at a given time period is denoted by $F^e_{j',j}(y,t)$. Then, the total energy available at node j is

$$Y^e_j(y,t) = \sum_{i=1}^{N} X^e_{i,j}(y,t) + \sum_{j'} (F^e_{j',j}(y,t) - F^e_{j,j'}(y,t)),$$

in accordance with conservation of energy at that node. The energy flows between nodes are bounded by transmission constraints, $F^e_{j',j}(y,t) \le F^{max}_{j',j}(y)\ \forall y,t$.

The incentives of the gencos are formulated using a linear production cost and revenue model. Equilibrium generation and hence flows would be determined by solving the individual profit maximization problems simultaneously, which is equivalent to solving the following quadratic optimization problem as discussed in [18], [20]. The pricing/dual variable relationship at the equilibrium is also derived in [18]. Hence, the Nash equilibrium solution of the multi-nodal game with transmission constraints is obtained by solving:

$$\begin{aligned}\max_{X^e, X^c, F} \sum_{j,y,t} &\left\{ Y^e_j(y,t) P_{e,j}(y,t) - \sum_i c^e_i q^e_i(y,t) \right\} \\ &- \sum_{i,j,y,t} \frac{1}{2} \beta_j(y,t) (X_{i,j}(y,t))^2 \\ &+ \sum_{j,y} \left\{ Y^c_j(y) P_{c,j}(y) - \sum_i c^c_i q^c_i(y) \right\} \\ &- \sum_{i,j,y} \frac{1}{2} \bar{\beta}_j(y) (X^c_{i,j}(y))^2\end{aligned} \tag{8}$$

subject to capacity and transmission constraints

$$Y^e_j(y,t) = \sum_{i=1}^{N} X^e_{i,j}(y,t) + \sum_{j'} (F^e_{j',j}(y,t) - F^e_{j,j'}(y,t))\ \forall j \tag{9}$$

$$Y^c_{i,j}(y) - Y^c_{i,j}(y-1) = X^c_{i,j}(y-1) \tag{10}$$

$$X^e_{i,j}(y,t) \le Y^c_{i,j}(y)\ \forall y,t \tag{11}$$

$$q^e_i(y,t) = \sum_{j=1}^{M} X^e_{i,j}(y,t) \tag{12}$$

$$q^e_i(y,t) \le Y^c_i(y),\ \forall t,y. \tag{13}$$

$$F^e_{y,t,j,j'} \le F^{max}_{y,j,j'} \tag{14}$$

The parameters used in Equations (8)-(14) are defined in Table I.

Perfect Competition

Perfect competition refers to a market with sufficiently low concentration with many players where no individual player can influence price. Price always equals to marginal cost in such a scenario unlike a Cournot competition where prices are above marginal cost [18].

The Perfect Competition (PC) scenario differs from the Cournot model. The terms $\sum_{i,j,y,t} \frac{1}{2}\beta_j(y,t)(X_{i,j}(y,t))^2$ and $\sum_{i,j,y} \frac{1}{2}\bar{\beta}_j(y)(X^c_{i,j}(y))^2$ in (8) can be interpreted as *dead-weight loss* to the society due to the imperfect nature of competition, i.e., the loss in consumer surplus with prices set above efficient level of marginal cost [21]–[23].

The *perfect competition* (PC) objective function (without capacity payments) is defined as [18]

$$\begin{aligned}\tilde{V}(q) = \ \sum_{y=1}^{Y} \sum_{t=1}^{t_M} &\left\{ \left[\alpha(y,t) - \frac{\beta(y,t)}{2} \sum_j q^e_j(y,t) \right] \right. \\ &\left. \cdot \sum_i q^e_i(y,t) - \sum_i c^e_i q^e_i(y,t) \right\} \\ &- \sum_{y=1}^{Y} \sum_i \left\{ c^c_i q^c_i(y) - \epsilon (q^c_i)^2(y) \right\}.\end{aligned} \tag{15}$$

Note that, the PC objective is the sum of player utilities defined in (1) and does not include the capacity payments $\sum_{j,y} q^c_j(y) P_{c,j}(y)$. This PC objective can also be related to the definition of price. If the constraints are omitted and given that ϵ is very small, then the first order sufficient conditions show that the price (approximately) equals marginal cost which is a characteristic feature of perfect competiton and an efficiently functioning market, i.e. no player exercises market power.

As expected, the solution $\tilde{q}$ that maximizes $\tilde{V}(q)$ may not necessarily coincide with the NE solution q^* in Proposition 2 where players exercise market power. However, if the game $\mathcal{G}^e = \{\mathcal{N}, q, U^e\}$ is modified carefully by introducing an additional incentive term $f_i(q)$ to the individual profit objectives of the firms, $\tilde{U}^e_i(q) = U^e_i(q) + f_i(q)\ \forall i$, then it is possible to modify the NE, $\tilde{q}^*$, of the new game $\tilde{\mathcal{G}}^e = \{\mathcal{N}, q, \tilde{U}^e\}$ such that it coincides with the "perfect competition" solution, i.e. $\tilde{q}^* = \tilde{q}$, as discussed in [26].

Proposition 5. *Let q^* denote the NE of the game $\mathcal{G} = \{\mathcal{N}, q, U^e\}$ defined in Proposition 2. If the profit function of the players are modified by introducing an incentive term such that*

$$\begin{aligned}\tilde{U}^e_i(q) = \sum_{y=1}^{Y} \sum_{t=1}^{t_M} \{ q^e_i(y,t) P_e(y,t) - c^e_i q^e_i(y,t) \} - \sum_{y=1}^{Y} c^c_i q^c_i(y) \\ -\epsilon \sum_{y=1}^{Y} (q^c_i)^2(y) + \sum_{y=1}^{Y} \sum_{t=1}^{t_M} \frac{\beta_i(y,t)}{2} (q^e_i)^2(y,t) + k_i\,,\end{aligned} \tag{16}$$

where k_i is a player-specific constant, then the NE, $\tilde{q}^*$, of the new game $\tilde{\mathcal{G}}^e = \{\mathcal{N}, q, \tilde{U}^e\}$ coincides with the "perfect competitive" solution

$$\tilde{q} = \arg\max_{q \in \Omega^N} \tilde{V}(q)$$

under the constraints $A(y,t)q(y,t) \le b(y,t),\ \forall t,y.$

Proof. The proof is provided in the Appendix. □

While Proposition 5 provides an interesting theoretical insight on potential improvement of market efficiency [27] within the context of this specific model, it is not immediately clear how the incentive terms in (16) can be implemented in practice. Capacity markets constitute one practical possibility in this direction. As the case study in the next section discusses in detail, capacity markets may enable the Nash equilibrium to move closer to the perfect competition counterpart.

IV. Numerical Analysis

A. Case Study and Setup

The South Australian region of NEM is a relatively small market with less than 5 GW of installed capacity at present. About three-fourth of the approximately 14 TWh annual generation comes from lignite coal and gas. However, this is expected to change significantly in the coming years. The energy requirement in the market is expected to grow very slowly from around 13 TWh in 2012 to just over 15 TWh in 2030 under the Medium Economic Growth scenario, which assumes an annual compound growth rate well below 1%.

There are two key attributes of the South Australian electricity market that should be highlighted before applying the Cournot model developed:

1) It is a highly concentrated market that has major connotation for exercise of market power; and
2) The market already has significant share of wind generation with a high degree of variability.

We elaborate on these two points below. The market is heavily concentrated at present with three players accounting for 70%-80% of average annual market share. We simulate the Energy Only Market (EOM) and Capacity-Energy Market (CEM) paradigms discussed in the preceding section for the South Australian market for 2013-2030. The input data and assumptions for this modeling including demand, available generation portfolio, availability, etc are sourced from AEMOs National Transmission Network Development Plan (NTNDP) [19]. We have modeled the NEM as a two-node market with South Australia and Rest of the NEM as two nodes connected by a line with a flow limit [20].

The market share of the generators in calendar year (CY) 2012 are depicted in Figure 1, which shows that 77% of the market was supplied by three gencos. As a starting point for our analysis we calibrate the energy-only Cournot model (1)-(2) to reproduce the observed prices and market shares closely. The calibration process essentially estimates the parameters of the inverse demand function and contract level that reasonably reproduce the observed market outcomes. The calibration methodology for EOM is discussed in [28]–[30]. In order to simulate the CEM for South Australian market, we simultaneously calibrate the capacity and the energy components to ensure that the capacity and energy demand curve parameters align with long run marginal cost of generation in the market.

Wind generation capacity in NEM has grown from less than 400 MW in 2005/06, to over 1,200 MW in early 2013. Wind accounted for 26% of annual generation in 2012 – already well in excess of the 20% National Renewable Energy Target (RET) set for 2020.

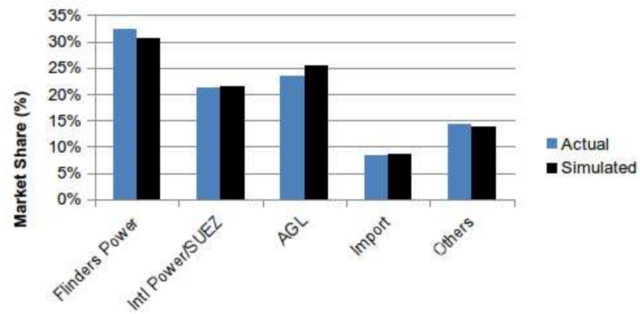

Fig. 1. Market share of South Australian generators in 2012.

There is significant daily, seasonal and inter-annual variability of wind generation in South Australia. Half-hourly wind generation data for July 2006 to April 2013 from AEMO has been used to develop a distribution of wind for each load block of load duration curve. The variability of wind has important attributes. Figure 2, which reflects half-hourly wind data for the Financial Year 2012/13 shows that the share of wind typically peaks in early morning hours when demand is at the lowest. In contrast, peak electricity demand more or less coincides with lowest share of wind generation.

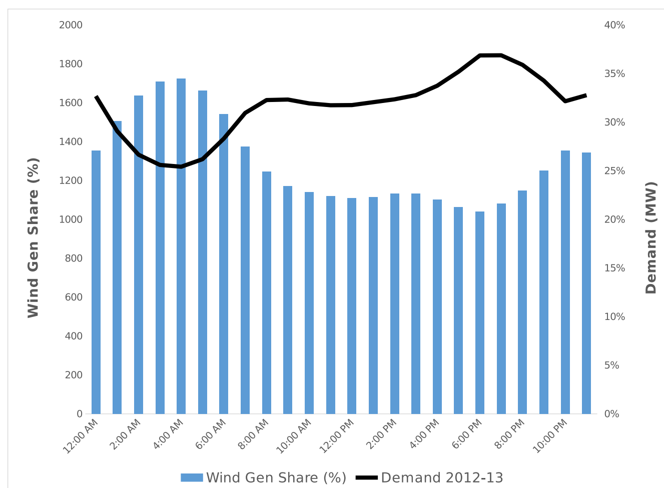

Fig. 2. Daily variability (2012-2013): average wind and demand profile (Source: AEMO).

Figure 3 shows capacity factor of aggregate wind capacity in South Australia from July 2006 (i.e., when SA had around 400 MW of wind capacity) to June 2013. There is significant seasonal trend with peak summer months typically observing a capacity factor below 30% which again reinforces the observation in Figure 2. Wind generation peaks around July when peak demand is typically 20% below summer peak. There is also significant year-on-year variation over the 7 year period. In order to capture this variability, we have (a) developed correlation between wind generation and load using

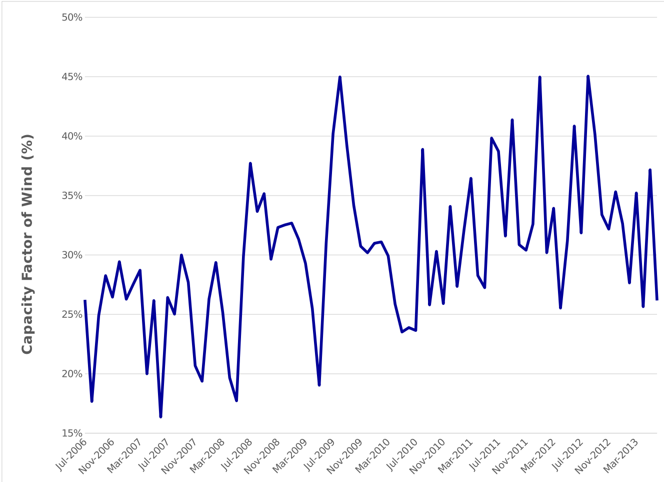

Fig. 3. Seasonal and inter-annual variability: capacity factor of South Australian wind (Source: AEMO).

half-hourly load data for 7 years; (b) developed a normalized distribution of wind generation for each load block of the load duration curve; and (c) investigated variability of wind generation using a Monte Carlo model that restricts availability of wind in each time period by sampling generation from a probability distribution. We have represented the distribution of wind generation based on a discretized version of the distribution shown above using 500 wind energy availability samples, and calculated the Cournot Nash equilibrium for each sample.

As discussed in [20] and above, the variability of wind has a significant bearing on dispatch and prices in South Australia. Figure 4 shows the average time distribution of wind in South Australia. The variability of wind for each half-hourly time period relative to the previous period is significant. We conduct a Monte Carlo analysis where we use a probability distribution shown in Figure 5 around the average profile using historic wind generation data that is obtained from AEMO [19].

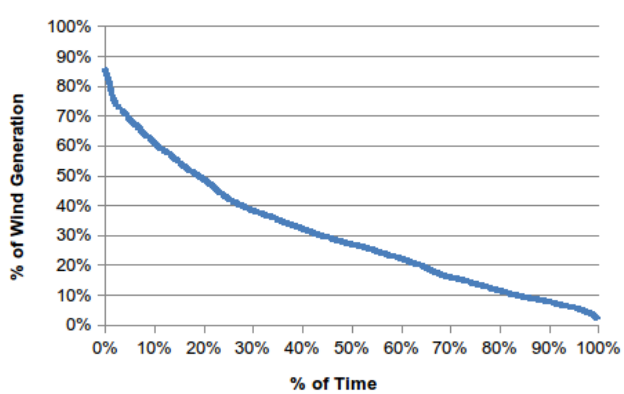

Fig. 4. Variability of wind: average profile over a year (Source: AEMO Wind Study Data [31]).

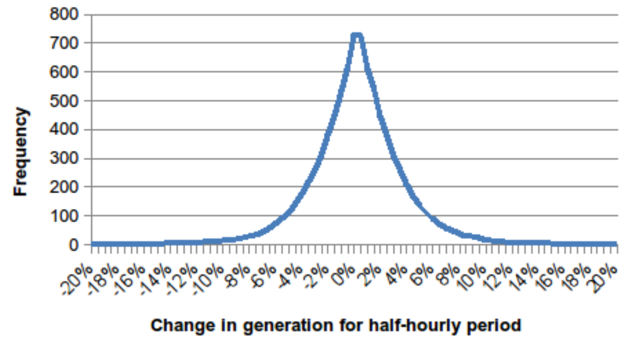

Fig. 5. Variability of power generation: frequency of variation over half-hourly periods in a year.

B. Simulations

We produce a capacity expansion plan for the least-cost or perfect competition (PC) scenario for FY 2013-2030, as shown in Figure 6. We assume a carbon price trajectory as per the Federal Treasury Core modeling scenario that is also included in the AEMO planning dataset [19]. Carbon prices under this scenario rise from real AUD 23/tonne in 2013 to AUD 61/tonne by 2030. We assume that the 20% RET will be continued until 2030 which effectively encourages significant entry of renewables which we capture in our model. As Figure 6 shows, wind will account for half of the long term capacity needs till 2030. Note that during this period, very little growth in energy demand is expected. The total wind capacity by 2030 is estimated to be 2,450 MW which will account for 7,726 GWh of generation, i.e., more than half of the annual energy delivered. Nevertheless, the existing gas generation and to some extent new gas generation are expected to provide a critical role together with other renewable resources including solar and biomass.

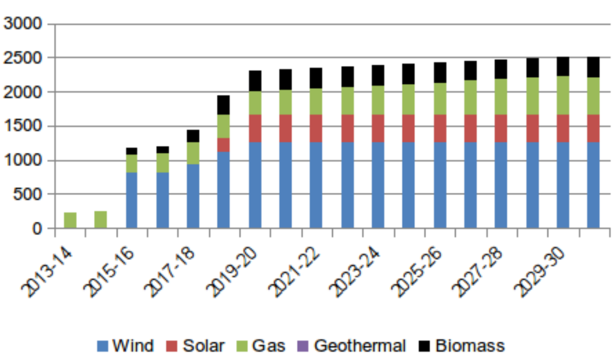

Fig. 6. Long term capacity plan for South Australia under perfect competition.

Next, we simulate EOM and CEM regimes for the medium economic growth scenario assuming:

1) The current portfolio of generation expands proportionally to accommodate the new entry, except for new biomass and geothermal capacity that form part of the

"fringe" competitive entrants with other small existing firms;
2) Medium economic growth scenario;
3) Continued existence of carbon prices;
4) Wind generation variability modeled using 500 random samples drawn from the distributions shown in Figure 4 and Figure 5. We effectively recalculate the Cournot Nash equilibrium as wind generation varies and in many cases may present opportunistic bidding behavior by the large gencos.
5) EOM uses a high price cap of AUD 13,100/MWh (real) and that for the CEM is much lower at AUD 1,310/MWh, i.e., one-tenth of the value in an EOM. The base value of 1,310/MWh broadly reflects price caps used in other capacity markets. As noted before, the EOM energy demand and CEM capacity and energy demand curve parameters are co-calibrated to ensure the two models produce the same price outcomes (in terms of the long run marginal costs) for the existing generation portfolio.

Figure 7 shows total new capacity entry in the market for least-cost/PC, EOM and CEM scenarios. In all cases, the long term capacity stabilizes after 2029/30 given the slow increase in demand, but there is a significant gap in capacity in the EOM scenario. There is 366 MW less capacity by 2030/31 in EOM relative to the PC and 466 MW less relative to the CEM scenario. The latter scenario consistently adds higher capacity compared to the perfect competition (PC) scenario.

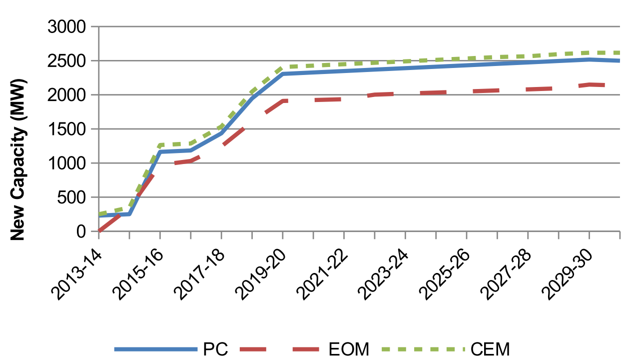

Fig. 7. Comparison of cumulative capacity entry: PC, EOM and CEM.

The difference in new entry is primarily due to gas capacity entry (both Open Cycle GTs and baseload CCGTs) as depicted in Figure 8. The CEM scenario adds as much as 666 MW of new gas capacity including a 300 MW CCGT. In comparison, EOM adds only 453 MW of OCGT. Although the differences are relatively small, there are reasonably significant ramifications for price efficiency across the two regimes as we discuss next.

It is important to note that the pricing impacts are "effects" caused by exercise of market power that is more prevalent in an EOM design. Put differently, price volatility is higher in the EOM because there is less gas capacity, specifically baseload CCGT capacity.

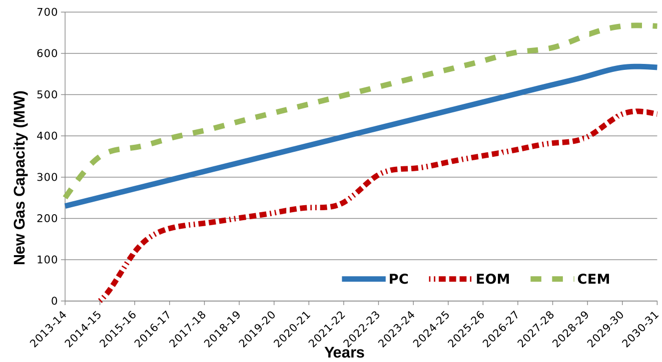

Fig. 8. Comparison of cumulative gas capacity entry (MW).

Figure 9 shows the equilibrium prices for 500 Monte Carlo sample runs for different wind profiles for 2013, i.e, with existing generation portfolio. In order to make the prices comparable, we combine capacity and energy prices for the CEM scenario to create a composite energy-only- equivalent price by levelizing the capacity price over the year and adding it to the energy price. At the left end are the "Low Wind" samples that typically allow aggressive bidding by dominant gencos during peak period to raise prices well above competitive price levels. This is because a significant part of the capacity in South Australia effectively becomes unavailable creating a state of low level of competition. Such a condition will render high degree of market power to other non-intermittent generators in the system - an effect that we have discussed at length in our previous analysis in [21]. In order to provide a benchmark tothe observed prices, in 2012/13 (July 2012 to 31 May 2013), prices in SA have averaged at AUD 65/MWh, or at the high end of prices in the left. The CEM and PC prices are much closer, albeit the former prices also diverge significantly under Low Wind condition. In other words, the market power issues in a CEM regime would also continue under a low wind generation situation, albeit less prominently compared to an EOM counterpart. It should also be noted that CEM and PC prices match very closely for Avg/High Wind conditions. The average prices across all 500 samples for EOM, CEM, and PC are AUD 47.8/MWh, AUD 42.9/MWh and AUD 40.4/MWh, respectively.

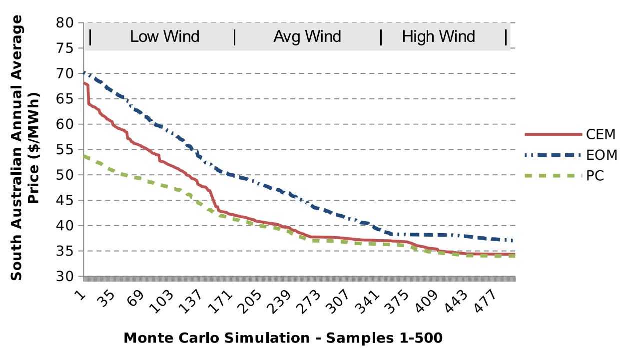

Fig. 9. Comparison of prices across random samples for 2013.

The longer term trend of prices across the three scenarios shown in Figure 10 demonstrates that prices over time will diverge, under the assumption that the current generation portfolios will grow over time (and hence market concentration will continue to be high) maintaining the existing level of contracting (as per the calibration). The prices in Figure 8 are averages across 500 Monte Carlo samples and load blocks modeled within each year. By 2030, EOM prices are 28% above the competitive level; a significant markup. In comparison, the composite capacity/energy price for CEM is 10% above the competitive level, which is mostly caused by surplus investment in capacity over and above a least-cost level would suggest.

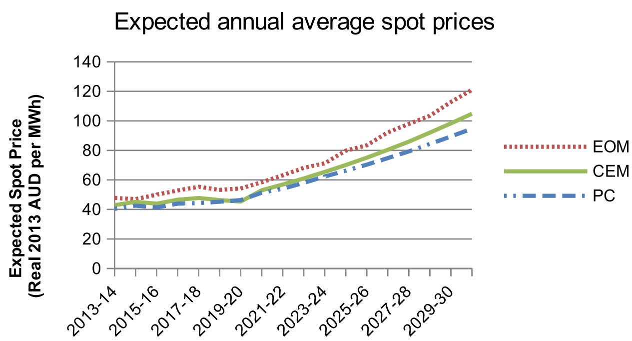

Fig. 10. Expected annual average spot prices (AUD/MWh).

Figure 11 provides some insights into the reason for price differences for EOM and CEM scenarios. In 2013 (solid lines), both scenarios have prices relatively close although the peak block prices for EOM at AUD 471/MWh for the top 100 hours is significantly higher than the CEM counterpart of AUD 351/MWh. However, the 2030 peak prices for EOM are nearly double that of CEM. CEM peak price indeed rises from 2013 level quite significantly to average over AUD 660/MWh due to significant increase in wind market share and associated volatility. In comparison, EOM peak and shoulder prices are very volatile and contain a significant premium due to strategic withholding of firm capacity during peak by the three dominant gencos. This finding sums up the risks faced in an EOM design under a high degree of intermittent generation penetration. The incentive for the same gencos in a CEM is far less diminished due to the presence of a capacity payment which in turn encourages a greater volume of new entry, and also a substantially lower price cap. It may also be worth noting that the tail of the price duration curve for EOM scenario is actually lower than that for CEM. This suggests that in an EOM setting, highly volatile peak/shoulder prices would also be accompanied by significantly depressed off-peak prices. This in part explains the lack of gas capacity entry that we have discussed before.

In summary, we can collate the key observations to develop good insights into the ramification of introducing a capacity market, as follows:

1) the presence of a capacity market dampens the need for earning excessive profits during a limited number of

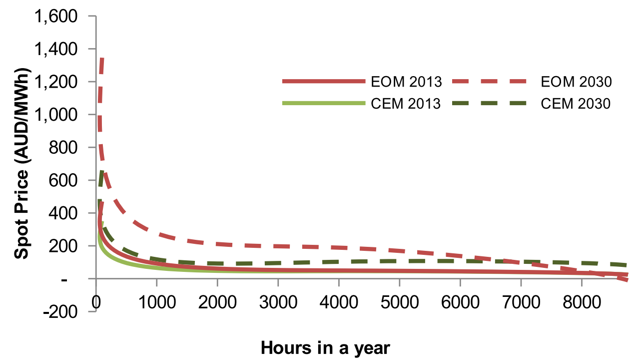

Fig. 11. Price duration curves for 2013 and 2030: EOM and CEM.

hours of very low reserve margin as noted by Hogan [32] among others. This is particularly important under a high degree of intermittent renewable generation that may not be available during peak demand periods. This is best captured in Figure 9 which shows how low wind conditions may cause the EOM prices to be substantially above those under a CEM regime;
2) increased penetration of wind may exacerbate the problem of EOM to "*raise the specter of market power*" as Hogan described it in 2004/05 [32], over the years. Figure 10 shows that EOM annual average prices diverge away from the CEM counterparts over the years considerably as wind capacity continuously grow to account for approximately half of the installed capacity by 2030. The ability to push prices above the competitive level under low wind conditions may allow prices to be higher by 18% relative to CEM which is a significant problem.
3) A higher propensity to abuse market power under the EOM regime is also evident if we look at the shape of price duration curves in Figure 10. It shows that prices during the summer peaks which coincide with low wind periods have substantially higher price than those under the CEM. The presence of a capacity market provides revenue certainty and together with a lower price cap leaves less room for gencos to exercise market power. These finding sum up the risks faced by consumers/retailers in an EOM design under a high degree of intermittent generation penetration. The opportunity for the same gencos to exercise market power in a CEM is diminished due to the presence of capacity payments which in turn encourage a greater volume of new entry. It may also be worth noting that the tail of the price duration curve for EOM scenario is actually lower than that for CEM. This suggests that in an EOM setting, highly volatile peak/shoulder prices would also be accompanied by significantly depressed off-peak prices. The shape of price duration curve under EOM presents greater risks to gencos and retailers alike. A depressed price during off-peak naturally discourages

baseload investment. This in part explains the lack of gas capacity entry as we have discussed before.

V. Conclusion

In this paper, we have analyzed the ramifications of high wind penetration in South Australia, a highly concentrated part of the Australian National Electricity Market. Motivated by our recent analysis of the same market [20] as well as that of Mountain [33] that showed significant increase in market power especially during peak and shoulder periods, this analysis further probes potential changes in market design and the longer term capacity entry and price implications. In particular, we have explored a capacity and energy market (CEM) design which in conjunction with the existing energy-only market (EOM) design have been compared and contrasted with a perfectly competitive benchmark.

We have developed a multi-commodity inter-temporal Cournot game-theoretic model to simulate a capacity-energy market over time. The inter-linkage among the two products, namely capacity and energy, are preserved through constraints linking generation and capacity. Our models helped us investigate how new entry would occur under different market design choices in a concentrated market with high share of intermittent renewables. Such market conditions do not necessarily lead to new capacity. However, market design choices may lead to a different capacity mix which may differ from the optimal combination that a well-designed market wants to achieve.

Thus, our findings generally indicate that a CEM design performs better than EOM. Although the market power issues during peak/shoulder cannot fully be eliminated under CEM, especially for a low wind availability condition when incumbent dominant gencos possess significant ability to exercise market power, prices are significantly closer to the competitive benchmark compared to those under EOM. The CEM design also incentivizes significantly higher new entry compared to the EOM. In fact, there is a higher capacity entry relative to the competitive benchmark and in this sense, introduces a degree of inefficiency. However, we have calculated the composite energy price for the CEM scenario with levelised capacity costs and it shows long term prices are 10% higher compared to a competitive level. The EOM scenario yields prices that are 28% higher than a competitive benchmark. Although there is significant excess capacity in South Australia at present, it has been driven primarily through the Renewable Energy Target. Since the market, notwithstanding the excess capacity, shows symptoms of market power, it is important that the market design issues raised in this study is probed further to understand the efficacy of the current energy-only market design.

Appendix

Proof of Proposition 2

In the N-player nonzero-sum strategic (noncooperative) static game $\mathcal{G} = \{\mathcal{N}, q \in \mathcal{Q}^e, U^e\}$, the strategy space $\mathcal{Q}^e$ is assumed to be convex, compact and non-empty. The player utilities $U_i,\ i = 1, \dots, N$ defined in (1) are continuous on $\mathcal{Q}^e$ and concave in q_i from Lemma 1. Thus, from Theorem 4.4 in [34], the game $\mathcal{G}$ admits a Nash equilibrium solution, q^*, in pure strategies.

Proof of Proposition 5

The perfect competition objective $\tilde{V}(q)$ defined in (15) is concave in its arguments for any $\epsilon > 0$ for its Hessian can be written as a sum of a negative semi-definite matrix and a negative definite diagonal matrix [24]. The necessary and sufficient Karush-Kuhn-Tucker (KKT) conditions of the corresponding Lagrangian coincides exactly with those of the individual optimization problems, $\max_{q_i} \tilde{U}_i(q)$, of players with modified profit functions, which are concave in q_i. Thus, the result in Proposition 5 immediately follows.

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