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Analysis of Imperfect Competition in Natural Gas Supply Contracts for Electric Power Generation: A Closed-loop Approach

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Abstract

The supply of natural gas is generally based on contracts that are signed prior to the use of this fuel for power generation. Scarcity of natural gas in systems where a share of electricity demand is supplied with gas turbines does not necessarily imply demand rationing, because most gas turbines can still operate with diesel when natural gas is not available. However, scarcity conditions can lead to electricity price spikes, with welfare effects for consumers and generation firms. We develop an open-loop equilibrium model to evaluate if generation firms have incentives to contract or import the socially-optimal volumes of natural gas to generate electricity. We consider a perfectly-competitive electricity market, where all firms act as price-takers in the short term, but assume that only a small number of firms own gas turbines and procure natural gas from, for instance, foreign suppliers in liquefied form. We illustrate an application of our model using a network reduction of the electric power system in Chile with two strategic firms that make annual decisions about natural gas imports in discrete quantities. Our results indicate that these firms have incentives to sign natural gas contracts for volumes that are much lower than the socially-optimal ones. These strategies result in higher profits for strategic firms than under the socially-optimal import levels of natural gas. Interestingly, this effect is rather sensitive to the price of natural gas. A high price almost eliminates the incentives of generation firms to exercise market power through natural gas contracts.

Keywords: Market power, Natural gas, Electricity market, Generalized Nash equilibrium, Equilibrium Problem with Equilibrium Constraints

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1. Introduction

Natural gas has become an important resource for electricity generation. Since the 1980s, the share of electricity produced worldwide using natural gas has increased from 8% to nearly 23% in 2015 (EIA, 2019a). This increase in the use of natural gas for electricity production is a consequence of aggressive extraction efforts in the U.S., Asia Oceania, the Middle East, and Africa (Moniz et al., 2011) and a reduction in the Henry Hub natural gas spot price from 14.2 \$/MMBtu in 2005 to a low of 2.6 \$/MMBtu in 2016 (EIA, 2019b). While the increasing levels of penetration of renewable energy resources and storage are expected to reduce our reliance on fossil fuels, the International Energy Agency predicts that the use of natural gas for electricity generation will keep increasing up to 2027 in a Sustainable Development Scenario, in line with the Sustainable Development Goals set by the United Nations (EIA, 2019a).

Gas turbines are valuable assets in systems with large shares of generation from wind and solar resources. Unlike coal units, gas turbines can provide flexibile supply of power that can be used to balance the variability and unpredictability of wind and solar resources (Moniz et al., 2011; Lee et al., 2012). They can also provide these services at lower costs and with lower emissions levels than diesel units. Yet, the availability of natural gas is not uniform around the globe and many countries, states, or generation firms must rely on cross-border trading and the development of costly infrastructure to secure the availability of this fuel for the production of electricity.

Gas pipelines are a common alternative for the transportation of natural gas from suppliers to generation firms in all continents. For longer distances, when it cannot be delivered on land, natural gas is often transported in liquefied form (LNG), which requires gas liquefaction plants, gas tankers, and LNG terminals, in addition to gas pipelines. Given the high overhead costs of developing such infrastructure and the price volatility of natural gas in international markets, it is common for generation firms or midstreamers to secure the supply of this fuel through contracts for prices and volumes that are determined prior to its use for electricity generation (Abada et al., 2017). In some cases, these contracts can include take-or-pay clauses or indexation parameters that give suppliers additional alternatives to manage risk (Masten and Crocker, 1985).

A salient feature of gas generation is that changes in the availability or price of natural gas can have large effects on electricity prices. For example, beginning in 2004, Chile experienced a long period of scarcity of natural gas for electricity generation due to a political an economic crisis in Argentina, its main supplier of this fuel. The gas shortage did not result in demand rationing of electricity because gas units were still able to operate with diesel (Raineri, 2006). However, electricity prices increased from an average of 25 \$/MWh, prior to the period of natural gas restrictions, to more than 300 \$/MWh in the fall of 2008 (Systep, 2019). Cold winters and a high demand of natural gas for heating can also limit the availability of this fuel for power generation. For instance, in the electricity market of New England in North America, the average electricity price during the unusually cold winter of 2013/2014 was 137.6

$/MWh, whereas the average electricity price in the same season of 2015/2016, with milder temperatures, was just 27.6 $/MWh (ISONE, 2019). The price spike during the winter of 2013/2014 occurred due to constraints in gas pipelines or delayed LNG deliveries, leading to high natural gas prices in local markets. Periods of scarcity of natural gas have also been a concern in the electricity markets of California, the Midcontinent ISO, PJM, and the New York ISO (Walton, 2016).

Under ideal conditions, electricity price spikes provide efficient signals for investments and give incentives to consumers exposed to spot prices to reduce demand (Cramton, 2017). However, price signals become distorted and result in welfare losses if scarcity conditions are the result of strategic behavior by generation firms (Wilson, 2000).

Motivated by the strong linkage between the availability of natural gas and electricity prices, we propose and equilibrium model to evaluate if generation firms have incentives to procure the socially-optimal levels of natural gas for power generation. We develop a closed-loop equilibrium model considering transmission constraints and linear losses, as well as demand, wind, solar, and hydro variability. In this model we assume that all generation firms behave competitively in the electricity spot market. However, firms that import natural gas can make strategic decisions about import volumes, taking into account the effects of these decisions upon electricity prices and dispatch decisions. We formulate this model as an Equilibrium Problem with Equilibrium Constraints (EPEC) that we solve by a discretization of the strategy space of strategic firms. Thus solution approach allows us to identify all possible Nash equilibria of the game and develop a better understanding the firms' best response functions than what it would be possible using a complementarity-based approach. We also develop a planning model that identifies the socially-optimal levels of natural gas imports for all firms and that we employ as a benchmark in our analysis.

We illustrate an application of the proposed model using a 9-node network reduction of the main electric power system in Chile, considering two strategic firms that make commitments of natural gas import volumes prior to the operation of the electricity market. Our results indicate that firms have incentives to exercise market power by making natural gas more scarce than under the socially-optimal import volumes. While the scarcity of natural gas does not result in electricity demand curtailment, it raises electricity prices, which is captured by strategic firms through a portfolio of inframarginal units. We also find that, for the set of scenarios considered in our study, the incentives to exercise market power by strategic firms are more sensitive to the price of natural gas in international markets than on the availability of hydro resources for electricity generation. Furthermore, we study the effect of different natural gas contract types—flexible or inflexible—that firms can report to the System Operator (SO). We find that the contract type has a negligible influence on the type of Nash equilibria we identify for each scenario of hydro conditions and natural gas prices.

The rest of the paper is structured as follows. In Section 2 we review the existing literature on the different approaches to model strategic behavior in electricity and natural gas markets and on the interdependencies of infrastructure between these two areas. In Section 3 we present our methodology, describing the models employed in our analysis and the solution approach. In Section 4 we present a case study of the electric power system in Chile and our data assumptions to illustrate an application of the equilibrium models. In Section 5 we present our results considering different scenarios of system conditions. Finally, in Section 6 we conclude.

2. Literature Review

There is a broad array of models to study incentives for the exercise of market power in electricity markets (Ventosa et al., 2005). Strategic bidding in wholesale spot markets is often modeled using Nash-Cournot models of imperfect competition (Jing-Yuan and Smeers, 1999; Hobbs, 2001), with some empirical evidence that such models can provide a reasonable approximation of actual market outcomes when used appropriately (Bushnell et al., 2008). More elaborate models of supply function equilibria better represent the bidding mechanism than the Cournot assumption (Baldick et al., 2004), but they are much more difficult to solve if realistic features such as transmission constraints are considered (Holmberg, 2009). In two-settlements electricity markets (e.g., day-ahead and real-time markets), strategic behavior can be modeled using open-loop equilibrium models of imperfect competition (Yao et al., 2008).

Strategic bidding in wholesale spot markets is not the only manner in which generation firms can exercise market power. For instance, if in a concentrated market firms are aware that they will subject to very strict market power mitigation measures or to a cost-based market, they could still behave strategically by selecting investments in specific types, sizes, and locations of generation units that would result in higher profits than under price-taking behavior. This result was first demonstrated by Kreps and Scheinkman (1983) in generic form and further explored by Murphy and Smeers (2005), Wogrin et al. (2013b), and Munoz et al. (2018) using open-loop equilibrium models applied to investment problems in electricity markets.

Generation firms can also exercise market power by untruthfully reporting unit parameters such as ramping limits or minimum generation levels, or by taking advantage of these constraints on sequential markets. This issue was first studied by Kai et al. (2000) and later extended by Oren and Ross (2005); Moiseeva et al. (2015) and Moiseeva et al. (2017) using more sophisticated models, such as conjectural variations and open-loop equilibrium problems. There is also empirical evidence that generation firms have incentives to engage in such practices. In 2013, the firm J.P. Morgan was fined \$410M for strategic bidding in day-ahead and real-time markets, taking advantage of the Make Whole Payment mechanism through binding ramping limits in the electricity market of California (FERC, 2013). Interestingly, such strategic behavior is not limited to bid-based electricity markets, which are common in the U.S. and in Europe. The electricity market in Chile relies on a cost-based mechanism for the dispatch and pricing of generating units in the short term, which means that firms are not allowed to submit bids. Nevertheless, there have been two cases of generation firms being fined for untruthfully reporting minimum generation levels and up times that lead to increased profits, higher operating costs and prices, and the spillage of solar resources (REI, 2016, 2018).[1]

There are also models of imperfect competition applied to natural gas markets. Gabriel et al. (2005a) and Gabriel et al. (2005b), for instance, develop mixed-complementarity problems of Nash-Cournot competition in natural gas markets, considering producers, storage and peak gas operators, third-party marketers and end-use operators. Holz et al. (2008) applies similar models of Nash-Cournot competition to European gas markets considering multiple market settings (e.g., Cournot competition in upstream markets, downstream markets, or in both). Abada et al. (2017) develops a more elaborate equilibrium model considering uncertainty, risk-averse agents, and endogenous natural gas contracts, but assuming price-taking agents.

Nevertheless, we are only aware of one previous article studying the effects of strategic natural gas procurement decisions upon the electricity market, as we do in this paper. Duenas et al. (2012) propose an equilibrium model that considers both multi-year natural gas contracts and participation in the electricity market, assuming that generation firms take into account the impact of their production decisions using a model of conjectural variations. We improve upon the model proposed by Duenas et al. (2012) by developing an open-loop model of imperfect competition instead of one of conjectural variations and by considering transmission constraints. As it has been documented, equilibrium outcomes can be very sensitive to the choice of conjectural variation, which might be also inconsistent with the actual ability of a firm to affect prices in equilibrium (Lindh, 1992; Díaz et al., 2010). The rest of the existing literature that addresses the interdependencies between natural gas infrastructure and electric power systems focuses mostly on the economic benefits of co-optimized decisions of natural gas infrastructure and electric power systems (Shahidehpour et al., 2005; Li et al., 2008; Chaudry et al., 2014; Toledo et al., 2016), disregarding strategic behavior.

3. Methodology

In this section, we describe an open-loop equilibrium model of imperfect competition to study the incentives of strategic firms to exercise market power in the electricity market by selecting natural gas contract volumes that differ from the socially-optimal levels and a planning model. In Section 3.1 we first describe the open-loop equilibrium model formulated as an EPEC, where strategic generation firms select natural gas contract volumes taking into account the

[1] As discussed in Munoz et al. (2018), cost-based electricity market designs do not necessarily prevent firms from exercising market power due to the usual information asymmetries between the SO (or regulator) and generation firms, compounded by the difficulty of performing periodic audits to validate the technical parameters of all generation units in a system.

effect of these decisions in the optimal dispatch decisions and electricity prices determined by the SO. In Section 3.2 we describe a planning model that provides the socially-optimal outcomes.

For simplicity, we assume that the electricity market is perfectly competitive and focus only on strategic behavior in natural gas supply contracts for power generation. In bid-based electricity markets, such as many of the deregulated markets in North America, Europe, Australia, and New Zealand, this assumption implies that all firms submit bids that reflect their true marginal costs and that do not withhold generation capacity. In cost-based markets, such as the ones in Chile, Bolivia, Perú and countries in Central America, perfect competition means that the SO has access to all the relevant information needed to determine the true marginal cost of generation of all units in the system, including all relevant opportunity costs.

These are, of course, convenient assumptions that simplify our models. In practice, generators might have incentives to exercise market power in bid-based markets with few dominant firms and weak transmission systems (Borenstein et al., 1999). Furthermore, in cost-based markets the SO might not be able to compute all relevant opportunity costs for generators, which could yield inefficient dispatch schedules and prices (Munoz et al., 2018). Nonetheless, the models proposed here can be extended directly using, for instance, the assumption of Cournot competition among firms in the electricity market. Modeling imperfect competition in the electricity market is beyond the scope of this paper and we leave it as subject for future research.

Nomenclature

Set definitions

$\mathcal{B}$	Buses or nodes, indexed b
$\mathcal{J}$	Generation firms, indexed j
$\mathcal{G}$	Generation units in the system, indexed i
$\mathcal{G}(j)$	Subset of generation units owned by firm j
$\mathcal{G}(b)$	Subset of generation units at bus b
$\mathcal{L}$	Transmission lines, indexed l
$\mathcal{T}$	Operating periods, indexed t

Parameters

CF_i	Maximum annual capacity factor
D_{bt}	Demand level [MW]
F_l	Line thermal limit [MW]
FOR_i	Forced outage rate
G_{ij}	Generator-firm incidence matrix
H_t	Length of time period [hrs]
HR_i	Generator heat rate [MMBtu/MWh]
IM_{lb}	Line-bus incidence matrix

K_i	Generation capacity [MW]
MC_i	Marginal cost of generation [$/MWh]
$LOSS_l$	Transmission loss
$VOLL$	Value of lost load [$/MWh]
W_{it}	Availability factor of generation technology

Decision variables

f^+_{lt}, f^-_{lt}	Power flows [MW]
q_{it}	Dispatch level [MW]
u_{bt}	Demand curtailment [MW]
x_j	Volume of natural gas contracted for the year [m^3]

3.1. Open-loop equilibrium model

3.1.1. Lower-level Problem

In the lower-level problem we assume that generation firms act as price takers with respect to the locational marginal prices computed by the SO, taking the contracted volumes of natural gas as x_j as parameters. With inelastic demand, it is possible to compute a solution of the resulting equilibrium problem by solving an equivalent optimization program, where the SO minimizes annual operating costs by selecting dispatch schedules, load curtailment levels, and line flows (Samuelson, 1952; Munoz et al., 2017).

The following linear program describes the optimization problem solved by the SO in the lower level:

$$min \sum_{t\in\mathcal{T}} H_t \cdot \left[\sum_{i\in\mathcal{G}} MC_i \cdot q_{it} + \sum_{b\in\mathcal{B}} VOLL \cdot u_{bt}\right] \tag{1}$$

Subject to:

$$D_{bt} - \sum_{i \in \mathcal{G}(b)} q_{it} - u_{bt} - \sum_{l \in \mathcal{L}} IM_{lb} \cdot \left[LF^+_{lb} \cdot f^+_{lt} - LF^-_{lb} \cdot f^-_{lt} \right] = 0 \quad (p_{bt}) \quad \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{2}$$

$$f^+_{lt} - F_l \leq 0 \quad (\mu^+_{lt}) \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{3}$$

$$f^-_{lt} - F_l \leq 0 \quad (\mu^-_{lt}) \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{4}$$

$$q_{it} - K_i \cdot W_{it} \cdot (1 - FOR_i) \leq 0 \quad (\lambda_{it}) \quad \forall i \in \mathcal{G}, t \in \mathcal{T} \tag{5}$$

$$\sum_{t \in \mathcal{T}} H_t \cdot q_{it} - CF_i \cdot K_i \sum_{t \in \mathcal{T}} H_t \leq 0 \quad (\beta_i) \quad \forall i \in \mathcal{G} \tag{6}$$

$$\sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{G}} H_t \cdot HR_{it} \cdot G_{ij} \cdot q_{it} - x_j \leq 0 \quad (\eta_j) \quad \forall j \in \mathcal{J} \tag{7}$$

$$q_{it} + q_{e(i)t} - K_i \cdot W_{it} \cdot (1 - FOR_i) \leq 0 \quad (\psi_{it}) \quad \forall i \in \mathcal{G}_G, t \in \mathcal{T} \tag{8}$$

$$f^+_{lt}, f^-_{lt} \geq 0 \quad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{9}$$

$$q_{it} \geq 0 \quad \forall i \in \mathcal{G}, t \in \mathcal{T} \tag{10}$$

$$u_{bt} \geq 0 \quad \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{11}$$

The parameters LF^+_{lb} and LF^-_{lb} are defined as follows:

$$LF^+_{lb} = 1 - \frac{LOSS_l}{2}(1 + IM_{lb}) \tag{12}$$

$$LF^-_{lb} = 1 - \frac{LOSS_l}{2}(1 - IM_{lb}) \tag{13}$$

Constraint (2) balances supply and demand at every node in every time period, considering line inflows/outflows and transmission losses. Note that if $IM_{lb} = 1$, then $LF^+_{lb} = 1 - LOSS_l$ and $LF^-_{lb} = 1$, which implies that if $f^+_{lt} > 0$ (i.e., there is power flowing into node b) there is a loss equal to $LOSS_l \cdot f^+_{lt}$. However, if $f^-_{lt} > 0$ (i.e., there is power flowing out of node b), then the line loss is accounted for at the node in the other end of the transmission line. Constraints (3) and (4) impose maximum flow limits on transmission lines.

In (5) we impose maximum generation limits per generator derated by average forced outage rates. We model wind and solar variability using hourly capacity factors W_{it} from historical data, for all other generation technologies $W_{it} = 1$. Constraint (6) imposes maximum annual capacity factors, which we use to constrain generation from hydro units. For those units, the Lagrange multiplier β_i is the value of an additional unit of water for electricity generation. Constraint (7) limits the amount of electricity that gas turbines can produce over the year taking as an input the contracted volumes of natural gas per firm x_j. For simplicity, here we ignore natural gas storage and transport constraints and assume that total volume of natural gas contracted per firm x_j can be used to power any of the gas turbines owned by firm j. However, natural gas storage and transport constraints can be accounted for extending our model with features from Toledo et al. (2016). In constraint (8) we limit the amount of power that a gas turbine i and its virtual diesel counterpart $e(i)$ can produce in a time period. This constraint can only be active if the SO finds that it is optimal to run the turbine with natural gas for some fraction of the time period t and with diesel for the remaining fraction of t.[2] In practice, we observe that this constraint never binds and $\psi_{it} = 0 \; \forall i \in \mathcal{G}_G, t \in \mathcal{T}$.

The KKT conditions of the optimization problem solved by the SO are the following ones:

$$0 \leq q_{it} \perp -H_t \cdot MC_i + p_{b(i)t} - \lambda_{it} - H_t \cdot \beta_i - \tag{14}$$

$$H_t \cdot HR_i \cdot G_{ij} \cdot \eta_j - \psi_{it} \leq 0 \qquad \forall i \in \mathcal{G}, t \in \mathcal{T} \tag{15}$$

$$0 \leq u_{bt} \perp -H_t \cdot VOLL + p_{bt} \leq 0 \qquad \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{16}$$

$$0 \leq f^+_{lt} \perp \sum_{b \in \mathcal{B}} IM_{lb} \cdot LF^+_{lb} \cdot p_{bt} - \mu^+_{lt} \leq 0 \qquad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{17}$$

$$0 \leq f^-_{lt} \perp \sum_{b \in \mathcal{B}} IM_{lb} \cdot LF^-_{lb} \cdot p_{bt} - \mu^-_{lt} \leq 0 \qquad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{18}$$

$$p_{bt} \text{ free} \perp D_{bt} - \sum_{i \in \mathcal{G}(b)} q_{it} - u_{bt} -$$

$$\sum_{l \in \mathcal{L}} IM_{lb} \cdot \left[LF^+_{lb} \cdot f^+_{lt} - LF^-_{lb} \cdot f^-_{lt} \right] = 0 \quad \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{19}$$

$$0 \leq \mu^+_{lt} \perp f^+_{lt} - F_l \leq 0 \qquad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{20}$$

$$0 \leq \mu^-_{lt} \perp f^-_{lt} - F_l \leq 0 \qquad \forall l \in \mathcal{L}, t \in \mathcal{T} \tag{21}$$

$$0 \leq \lambda_{it} \perp q_{it} - K_i \cdot W_{it} \cdot (1 - FOR_i) \leq 0 \qquad \forall i \in \mathcal{G}, t \in \mathcal{T} \tag{22}$$

$$0 \leq \beta_i \perp \sum_{t \in \mathcal{T}} H_t \cdot q_{it} - CF_i \cdot K_i \sum_{t \in \mathcal{T}} H_t \leq 0 \qquad \forall i \in \mathcal{G} \tag{23}$$

$$0 \leq \eta_j \perp \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{G}} H_t \cdot HR_{it} \cdot G_{ij} \cdot q_{it} - x_j \leq 0 \qquad \forall i \in \mathcal{J} \tag{24}$$

$$0 \leq \psi_{it} \perp q_{it} + q_{e(i)t} - K_i \cdot W_{it} \cdot (1 - FOR_i) \leq 0 \quad \forall i \in \mathcal{G}_G, t \in \mathcal{T} \tag{25}$$

3.1.2. Upper level equilibrium

We assume that there is a subset of strategic firms $\mathcal{J}_S$ that own natural gas turbines that contract a fixed amount of natural gas for the year x_j for a price GP, taking into account the effect of these decisions on electricity prices p_{bt} and

[2] A more sophisticated approach could be to introduce binary variables s_{it} that indicate whether a gas turbine is operating with gas ($s_{it} = 1$) or not ($s_{it} = 0$) in a given period t. We could then replace constraint (8) by $q_{it} \leq M \cdot s_{it}$ and $q_{e(i)t} \leq M \cdot (1 - s_{it})$, where M is a large positive number. Unfortunately, such formulation would make the lower-level equilibrium problem non-convex and the locational marginal prices p_{bt} that result from fixing the binary variables s_{it} to their optimal values would not necessarily support the optimal dispatch decisions of the SO (e.g., some generation units might operate at a loss) (O'Neill et al., 2005).

dispatch decisions q_{it}. Abusing notation, we denote x_{-j} the contract decisions of rival firms. Electricity prices and dispatch decisions can be now expressed as $p_{bt}(x_j, x_{-j})$ and $q_{it}(x_j, x_{-j})$, respectively. Given a set of natural gas contracts for all strategic firms (x_j, x_{-j}), the annual profits from electricity sales for firm $j \in \mathcal{J}_S$ can be expressed as follows:

$$\Pi_j(x_j, x_{-j}) = \sum_{t \in \mathcal{T}} H_t \sum_{i \in \mathcal{G}} G_{ij} \cdot \left[p_{b(i)t}(x_j, x_{-j}) - MC_i\right] \cdot q_{it}(x_j, x_{-j}) - GP \cdot x_j \quad (26)$$

We assume that each strategic firm $j \in \mathcal{J}_S$ is rational and selects a contract level x_j taking the rival's decisions x_{-j} as fixed quantities. We express the profit-maximization problem of each strategic firms as follows:

$$\max_{x_j} \Pi_j(x_j, x_{-j}) \quad (27)$$

Subject to:

$$x_j \geq 0 \quad (28)$$

Constraints (14) to (25)

Since constraints (14) to (25) are complementarity conditions, each strategic firm $j \in \mathcal{J}_S$ solves an optimization problem subject to the KKT conditions of the lower-level problem, also known as a Mathematical Problem with Equilibrium Constraints (MPEC). The set of all MPECs for all strategic firms $\mathcal{J}_S$ define an Equilibrium Problem with Equilibrium Constraints (EPEC).

3.2. A planning model of natural gas imports

We also formulate a planning model that to find the socially-optimal solution of the planning problem, assuming that a central authority could make such decision under perfect information. This planning model finds the import volumes of natural gas for strategic firms that minimize the total system cost (i.e., cost of supplying electricity plus the cost of natural gas imports).

The optimization problem of the central planner is formulated as follows:

$$\min_{q,u,x} \sum_{t \in \mathcal{T}} H_t \cdot \left[\sum_{i \in \mathcal{G}} MC_i \cdot q_{it} + \sum_{b \in \mathcal{B}} VOLL \cdot u_{bt}\right] + \sum_{j \in \mathcal{J}_S} GP \cdot x_j \quad (29)$$

Subject to:

Constraints (2)-(11), (28)

Note that if import levels x_j are continuous, the optimization problem of the central planner coincides with the solution of an open-loop equilibrium problem, where firms select natural gas import decisions at the same time they choose production levels in the electricity market (Samuelson, 1952; Munoz et al., 2017). However, if x_j are discrete variables, as we assume in our solution approach, this equivalency does not necessarily hold.

3.3. Solution approach

EPECs are not guaranteed to have a pure-strategy Nash equilibrium and, if one exists, it might not be unique due to nondifferentiability and noncuasiconcavity issues that are common in applications with transmission constraints (Ehrenmann, 2004). Therefore, identifying even one Nash equilibrium (if one exists) can be extremely challenging.

A common approach to identify stationary points of complex or large-scale games is through diagonalization (Ahn and Hogan, 1982). This process is akin to a Gauss-Seidel fixed-point iteration, where each player $j \in \mathcal{J}_S$ solves the MPEC problem described in the previous section, assuming that all of the other agents' strategies x_{-j} are fixed. The algorithm converges when no agent $j \in \mathcal{J}_S$ changes its strategy x_j from the previous iteration. Some examples of the application of this method to find stationary points of EPECs in electricity markets include Cardell et al. (1997), Hobbs et al. (2000), Su (2005), Hu and Ralph (2007), Yao et al. (2008), and Wogrin et al. (2013a). In general, convergence of the diagonalization method in these settings is not guaranteed and can be sensitive to choice of the point used to initiate iterations. Furthermore, in the presence of multiple Nash equilibria, the algorithm (if converges) will return only one Nash equilibrium for each starting point, making it hard to draw general conclusions about the problem.

Another solution alternative is the identification of Nash equilibria through the intersection of best-response functions (BRFs). Murphy and Smeers (2005), for instance, derive closed-form solutions of BRFs for a closed-loop investment game between a peaking generator and a base-plant unit, which allows them to characterize all possible Nash equilibria and provide general results. Wogrin et al. (2013b) follow a similar approach to compare the solutions of open- and closed-loop equilibrium models. However, the derivation of closed-form solutions to BRFs for all agents in equilibrium models with more realistic features, including intertemporal constraints (e.g., maximum generation per year) and transmission limits, is extremely difficult.

Here we employ a simple solution approach based on an approximation to the original equilibrium problem described previously. We assume that natural gas contract volumes x_j can only be made in discrete amounts (e.g., a multiple of the volume of gas that can be stored in one tank of an LNG carrier). This simplification allows us to compute BRFs for all strategic firms and then identify all possible Nash equilibria of the game. We compute solutions as follows:

1. First, we compute the maximum volume of natural gas that each generation firm could use over the set periods $\mathcal{T}$, denoted X_j^{Max}. We compute this bound by simply assuming that all gas units owned by firm j can operate at nominal capacity over all periods $t \in \mathcal{T}$. Under perfect information, we know that rational firms will always choose import levels x_j such that $0 \leq x_j \leq X_j^{Max}$.
2. Second, we focus on possible contract strategies x_j such that $x_j \in [0, X_j^{Max}]$ $\forall j \in \mathcal{J}_S$ and discretize the solution spaces $[0, X_j^{Max}]$ taking as a reference,

for instance, the volume of gas that can be stored in one tank of an LNG carrier.

3. Third, we solve the lower-level problem (i.e., economic dispatch) for each possible combination of contract volumes of strategic firms. This provides the optimal dispatch decisions $q_{it}(x_j, x_{-j})$ and locational marginal prices $p_{b(i)t}(x_j, x_{-j})$ needed to compute the profit function $\Pi_j(x_j, x_{-j})$ of each strategic firm $j \in \mathcal{J}_S$.
4. Fourth, we compute the BRF of each firm $j \in \mathcal{J}_S$, here denoted $F_j(x_{-j})$, by solving the following problem:

$$F_j(x_{-j}) = \text{argmax}\ \Pi_j(x_j, x_{-j})$$

5. Finally, we identify all Nash equilibria.

Note that the solution of the planning problem can be computed directly from this discretization, but it is also possible to find it by solving a mixed-integer linear program.

4. Case Study

We show an application of the model described in the previous section employing a 9-node network reduction of the main electric power system in Chile from Moreno et al. (2015), depicted in Figure 1. Table A.8 in Appendix shows line ratings for the 8 transmission corridors considered in our study. We consider a loss factor of 6% of power flows, which is equal to average transmission losses reported by the National Independent System Operator (CEN, 2018).

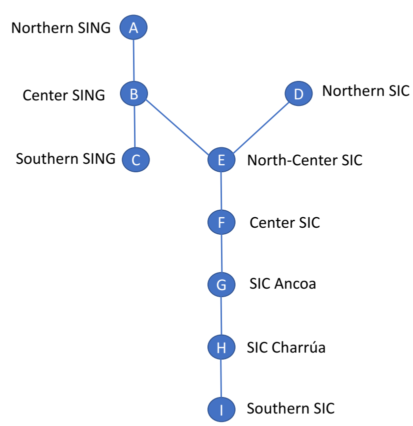

Figure 1: 9-node network representation of the main transmission system in Chile.

We assume that the two largest generation firms in the country, here denoted Firm 1 and Firm 2,[3] make decisions on natural gas imports strategically, anticipating the effect of their decisions on dispatch levels and electricity prices. These two firms own a diverse portfolio of generation technologies that can, in principle, help them capture the benefits of reducing the availability of natural gas in the system through other generation units with low operating costs, such as hydropower.

We group all other generation firms into a single competitive fringe that has a fixed level of natural gas available for the year in study based on historical data. Table 1 shows installed capacity per technology for the two strategic firms and the fringe. We want to highlight that the 1328.8 MW of gas generation capacity included in the fringe belong to small firms that, unlike Firm 1 and Firm 2, own little or no generation units that operate with fuels other than natural gas. Since, in practice, a large fraction of the natural gas utilized by fringe firms is purchased in local, secondary markets, our assumption to include these firms as part of a perfectly competitive fringe should not alter our results significantly.

Table 1: Installed generation capacity for the two strategic firms and the competitive fringe in MW.

Technology	Firm 1	Firm 2	Fringe	Total
Biogas	-	-	59.7	59.7
Biomass	-	-	425.9	425.9
Coal	370.0	661.8	4622.5	5654.3
Diesel	314.7	338.8	2259.4	2912.9
Gas turbine (dual)	1769.5	1644.8	1328.8	4743.1
Large hydro	741.0	1678.0	1037.0	3456.0
Mini hydro	26.8	30.0	396.3	453.0
Petcoke	-	-	75.0	75.0
Propane	-	-	14.5	14.5
RoR hydro	797.8	314.8	1391.2	2503.8
Solar	-	-	1704.6	1704.6
Wind	-	18.2	1302.5	1320.7
Total general	4019.8	4686.3	14617.3	23323.4

We employ a data set of nine hourly demand profiles (one per node), four profiles of wind generation, and two solar profiles for year 2016, all retrieved from publicly available resources (CEN, 2018) and Bergen and Muñoz (2018). While the original data set includes 8760 hourly observations for year 2016, we find that it is possible to capture a relatively large fraction of the variance of demand, hydro, wind, and solar profiles using only 25 representative time blocks selected using the K-means clustering algorithm (Munoz and Watson, 2015; Munoz et al., 2016). As shown in Figure A.8 in the Appendix, the total

[3] In this article we only use the electric power system in Chile as an application of our model, therefore, we prefer to omit actual firm names in order to avoid a potential misinterpretation of our results.

within-clusters sum of squares decreases more slowly with more than 20 clusters. We also include the 2 observations of minimum and maximum demand for the system, as in the constrained variant of the clustering method (Wagstaff et al., 2001).

We consider three scenarios for hydro power (dry, average, and wet) and three for natural gas prices (low, medium, and high) based on historical data. Additionally, following the current rules of the SO in Chile, we assume that generation firms can report natural gas contracts as either flexible or inflexible. Under both types of contracts the SO finds the most efficient use of the reported contracted quantities for the year, taking the contracted volumes as fixed parameters. I a contract is reported as flexible, the SO the operator optimizes all available resources assuming that the fuel cost of the gas-powered units owned by the firm with a flexible contract is equal to GC. In contrast, if the natural gas contract is reported as inflexible (e.g., due to a take-or-pay clause), the SO optimizes energy resources assuming that the cost of natural gas is equal to zero in Equation (1).[4] These three sets of scenarios result in the 18 cases listed in Table 2.

Table 2: Case studies for all possible scenarios of hydro conditions, gas prices, and contract types.

Case	Hydro scenario			Gas price GC [$\$/MMBtu$]			Contract type	
	Wet	Average	Dry	6.4	9.2	10.9	Flexible	Inflexible
1	•			•				•
2	•			•			•	
3	•				•			•
4	•				•		•	
5	•					•		•
6	•					•	•	
7		•		•				•
8		•		•			•	
9		•			•			•
10		•			•		•	
11		•				•		•
12		•				•	•	
13			•	•				•
14			•	•			•	
15			•		•			•
16			•		•		•	
17			•			•		•
18			•			•	•	

[4]Note that here we assume that the contract types are scenarios, not decision variables for strategic firms. However, one could also model the choice of a specific type of contract, flexible or inflexible, as a strategic decision variable in addition to contract volumes x_j.

5. Results

In this section we present our numerical results. We first use Case 1 and two simple illustrative examples to understand the shape of best response functions and the impact of transmission constraints upon our results. Next, we split the 18 cases shown in Table 2 between contract types, inflexible and flexible, which facilitates the analysis of the effect of natural gas prices and hydro scenarios on gas import decisions. All odd-numbered cases consider inflexible contracts and all even-numbered cases correspond to flexible ones.

All models were implemented using the Pyomo algebraic modeling language and solved with an academic license of CPLEX 12.4 in a personal computer with an Intel Core i5 processor @2.7 GHz with 8Gb of RAM. Each run of the economic dispatch model takes approximately 5 seconds and identifying best response functions for one case takes at most 3 hours.

5.1. Understanding the shape of best response functions

In this section we use results from Case 1 to explain the shape of best response functions. Figure 2 shows the best response functions of firms 1 and 2 in green and blue-colored dots, respectively. Gas import decisions are in cubic hectometers (10^6 m^3), denoted hm^3. We also indicate all Nash equilibria as orange-colored squares, at the intersection of best response functions. The socially-optimal import levels of natural gas are indicated using a black-colored triangle. We identified this unique solution for each case study using the planning model described in Section 3.2.

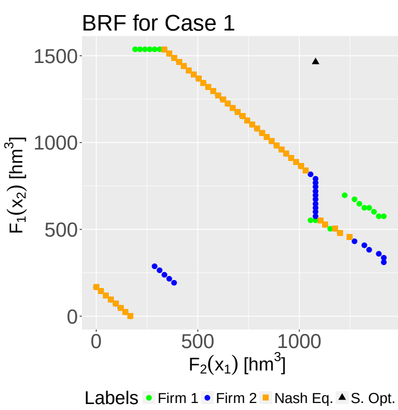

Figure 2: Best response function for Case 1, both axis are in cubic hectometres (hm^3).

Note that best response functions can have decreasing and constant sections, as well as some discontinuities or jumps between adjacent strategies of the rival firm. We first present a simple example to illustrate why, in most cases, best response functions are decreasing on gas import levels. We consider two firms and a fringe. Each firm owns a gas turbine and another generation unit, subindexes indicate ownership (e.g., GT_1 is owned by Firm 1). The variables x_1

and x_2 denote natural gas import levels that, in this example, are equivalent to the amount of generation capacity from gas turbines. For simplicity, we ignore the cost of natural gas in the dispatch and only consider its opportunity cost of dispatching a more expensive generating unit. The parameter D denotes the demand level, which is equal in all three figures (i.e., the red vertical line).

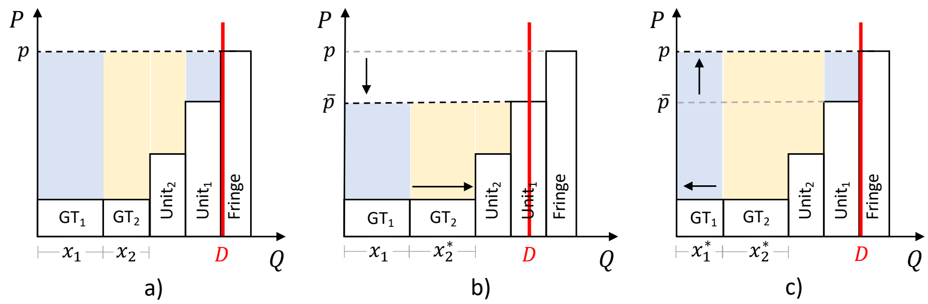

Figure 3: Illustrative supply curves for different import levels of natural gas.

Let's consider the best response function of Firm 1 to changes in x_2, denoted $x_1 = F_1(x_2)$, and assume that these import decisions result in the fringe unit setting the clearing price p, as we show in Figure 3 a). The light blue and yellow areas are the short-term profits of firms 1 and 2, respectively. Consider now that we want to know the best response function of Firm 1 to a new import level $x_2^* = x_2 + \Delta_2$, where $\Delta_2 > 0$. As shown in Figure 3 b), if Firm 1 maintains its import levels x_1, for a large enough value of Δ_2, the market-clearing price will drop to $\overline{p}$. The best response of Firm 1 to x_2^* will be to decrease its gas import level to $x_1^* = x_1 - \Delta_1$, where $\Delta_1 > 0$, such that the fringe unit will set the market-clearing price p again. As we illustrate in Figure 3 c), such action would allow Firm 1 to earn profits that are comparable to the ones depicted in Figure 3 a).

Note that, in this simple example, Firm 1 will choose $\Delta_1 \approx \Delta_2$; however, in a more general setting with different gas turbines, transmission constraint and losses, and heterogeneous generation portfolios between strategic firms, the optimal reduction of gas import for one firm Δ_1 will not necessarily be equal to an increase of gas import by the rival firm Δ_2. Surprisingly, in our case study, we find that the decreasing segments of all best response functions have, roughly, the same slopes. This means that, within each segment, $F_1(x_2) + x_2 = K$ and $x_1 + F_2(x_1) = K$, where K is some strictly-positive constant. Within each these segments the portfolios of gas turbines owned by the strategic firms are almost perfect substitutes.

Consider now the same example, except that now Unit_1 is part of the fringe. In Figure 4 a) we have the initial point x_2 and its best response by Firm 1, $x_1 = F_1(x_2)$. It is possible that, for a given $\Delta_2 > 0$ and $x_2^* = x_2 + \Delta_2$, the best response of Firm 1 $x_1^* = F_1(x_2^*)$ is to maintain its import level at x_1 (i.e., $x_1^* = x_1$). This occurs because the profit loss due to a reduction in gas imports by Firm 1 $\Delta_1 = x_1^* - x_1$ is greater than increase in profits due to a raise in

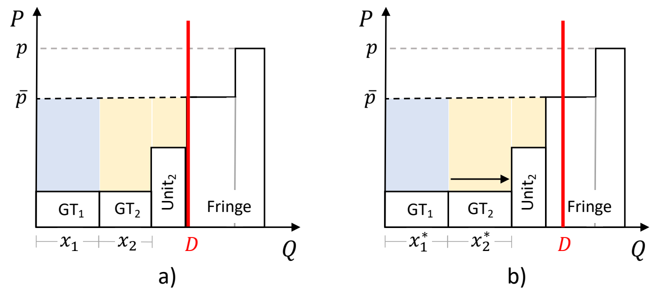

Figure 4: Illustrative supply curves for different import levels of natural gas.

the market-clearing price from p to $\overline{p}$. In our experiments, we find that flat or constant sections of best response functions are common in two situations. One is when the rival firm chooses to import a large volume of natural gas, such that the best response is to import a fixed amount for a range of imports of the rival firm. The other case is when the rival firm imports a small amount of natural gas, but the firm in question faces a capacity limit. In Figure 2 we find that this occurs for Firm 1 when Firm 2 selects import levels between 200 $hm^3$and 300 hm^3. Importing more gas is unprofitable for Firm 1 because the gas turbines that are part of its portfolio operate at their nameplate capacity.

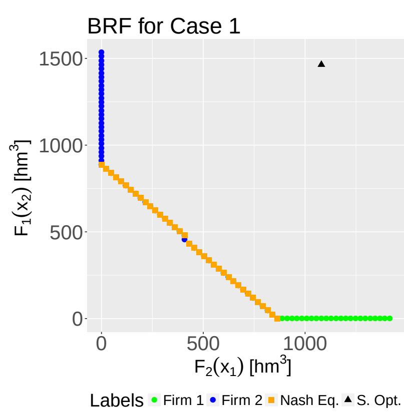

Figure 5: Best response function for Case 1 without transmission limits.

Finally, we observe that best response functions can also present large jumps between adjacent import decisions of the rival firm. For instance, the best response function of Firm 1 jumps abruptly from zero to nearly 1500 hm^3 for import decisions of Firm 2 between 200 hm^3 and 250 hm^3. Here we find that these discontinuities are mostly a result of a transmission constrained power system. In Figure 5 we show best response functions for a variant of Case 1, where we removed the thermal limits of transmission lines from the model (i.e., we omitted constraints (3) and (4)). Note that all the large discontinuities observed in Figure 2 are not present in Figure 5. In fact, without transmission constraints, best response functions are simply downward-slopping curves, up to a point where the rival firm saturates the market with generation from natural gas and the optimal strategy becomes importing zero gas. Our results are in line with Hu and Ralph (2007), where the authors illustrate how transmission constraints can cause discontinuities of best response functions of generation firms in a bid-based electricity market framed as an EPEC. However, Murphy and Smeers (2005) show that these jumps in best response functions can also appear in closed-loop investment problems without transmission constraints.

5.2. Nash equilibria for different scenarios of natural gas prices and hydro conditions

Here we present the resulting best response functions for the 18 cases considered. Our goal is to simply illustrate how different scenarios of natural gas prices, hydro conditions, and the type of natural gas contract affect the set of resulting Nash equilibria in each case. Figures 6 and 7 show best response functions for the cases with inflexible and flexible gas contracts, respectively. The plots are organized in a 3x3 matrix, where columns indicate different gas prices and rows represent different hydro conditions. The horizontal and vertical axes in each plot indicate best responses to annual natural gas import decisions by strategic firms 1 and 2, respectively, in hm^3.

Our first observation is that the 18 cases analyzed present multiple Nash equilibria, which we were able to find by assuming discretized strategy sets for firms 1 and 2. As discussed earlier, the existence of multiple Nash equilibria in EPECs is very common due to nondiferentiability and noncuasiconcavity issues (Ehrenmann, 2004) of our equilibrium problem. Finding all possible equilibria would have been very difficult using other solution methods, such as the ones based on the iterative solution of MPECs.

We find that, in most cases, firms have incentives to import natural gas volumes that are lower than the socially-optimal levels, i.e. all cases with low or medium natural gas prices. In all of those scenarios strategic firms exercise market power. Furthermore, in scenarios of low natural gas prices we find very two very distinct set of Nash equilibria, one with high import levels and other with low import levels of natural gas (e.g., Case 2).

However, in scenarios of high natural gas prices (third column of plots) the socially-optimal outcome is contained in the set of Nash equilibria. In this set of Nash equilibria, the portfolios of natural gas units are almost perfect substitutes (straight line with slope almost equal to -1). This means that the sum of natural gas imports by firms 1 and 2 in all equilibrium points with high natural gas prices is approximately the sum of the socially-optimal import levels.

Finally, comparing Figures 6 and 7 we observe that the type of contract (flexible or inflexible) does not seem to have a large effect upon the resulting set of Nash equilibria. The only exception are cases 7 and 8, where we observe that, under the same scenarios of hydro conditions and natural gas prices, the set of Nash equilibria that is closest to the socially optimum levels presents some sensitivity with respect to the type of contract. Given the similarity of results

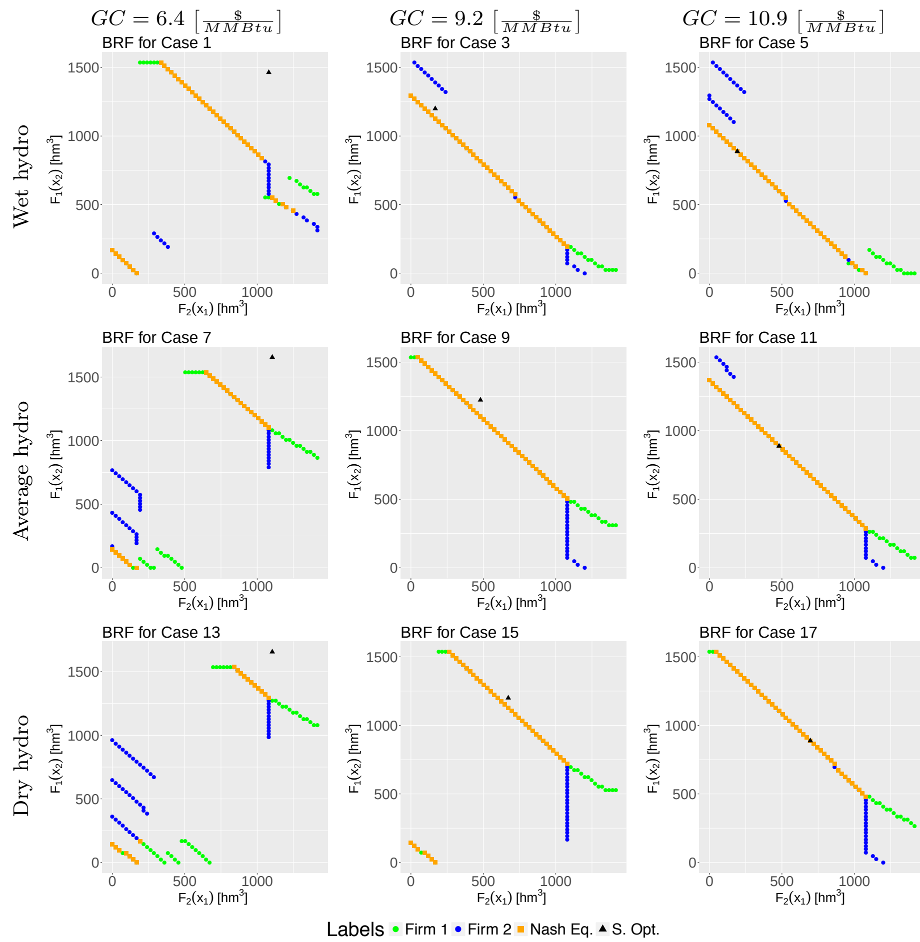

Figure 6: Best response functions for inflexible gas contracts under wet, average, and dry hydro conditions and under the three scenarios of natural gas prices. All axis indicate annual natural gas import decisions in hm^3.

between cases with inflexible and flexible contracts, in the next subsections we only focus on the analysis of different scenarios of hydro conditions and natural gas prices assuming inflexible contracts (odd-numbered cases).

5.3. Natural gas import decisions and dispatch levels

We now consider a subset of the possible Nash equilibria to understand how strategic behavior leads to outcomes that can differ significantly from the socially optimal plan. We select representative Nash equilibria that are either in the middle of a set of them in a line with slope equal to -1 or the closest Nash equilibrium to the socially-optimal plan. In cases where there are multiple lines of Nash equilibria (e.g., Case 1), we report one representative point from each

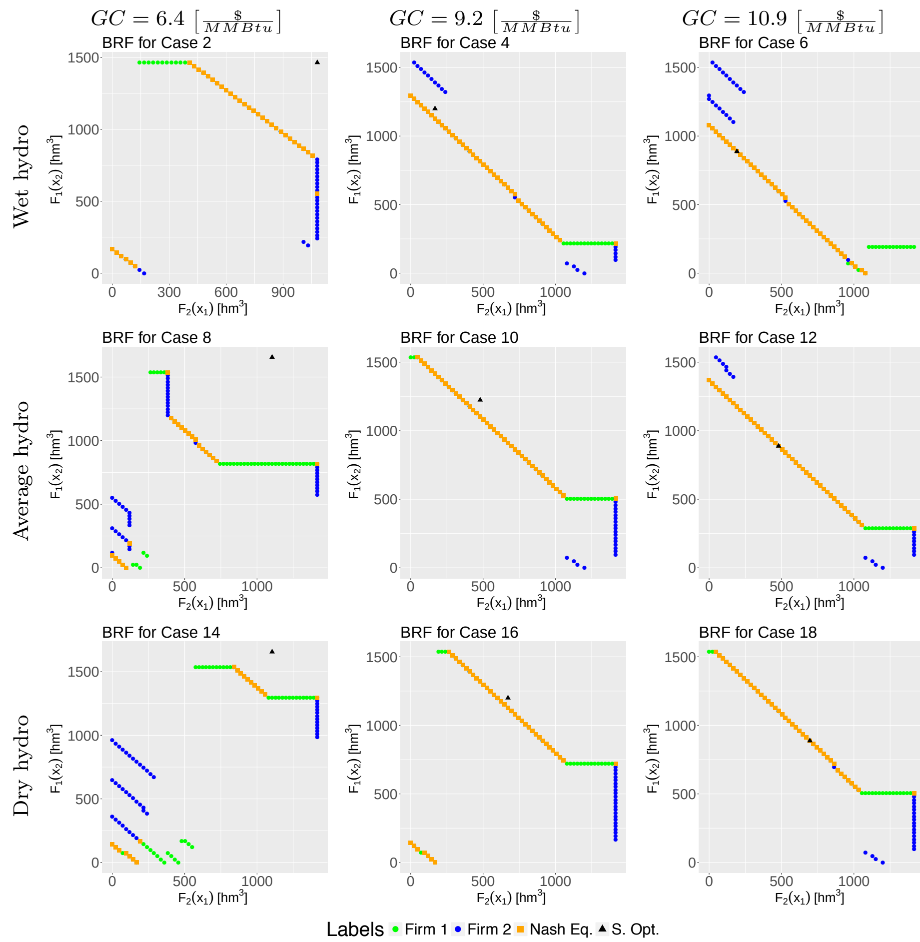

Figure 7: Best response functions for flexible gas contracts under wet, average, and dry hydro conditions and under the three scenarios of natural gas prices.

set. Hereinafter, we refer to them as Low N. Eq. and a High N. Eq. Table B.9 in the Appendix shows the import volumes per firm for the representative Nash equilibria and for the socially-optimal plan.

Table 3 shows aggregate natural gas import decisions in hm^3 for the two representative Nash equilibria and the socially-optimal plan, for each possible scenario of hydro conditions and natural gas prices under inflexible contracts. We observe that both hydro conditions and natural gas prices can have an incidence on import volumes. As expected, both high natural gas prices and abundant hydro resources for electricity generation reduce the incentives for firms and a hypothetical central planner to import natural gas. However, we find that the price of natural gas is the factor that results in the largest discrepancies between the socially-optimal level of natural gas imports and the

Table 3: Aggregate natural gas import decisions for firms 1 and 2 under imperfect competition and for the socially-optimal plan.

Case	Hydro	Gas price [\$/MMBTtu]	Low N. Eq. [hm^3]	High N. Eq. [hm^3]	S. Opt. [hm^3]
1	Wet	6.4	168	1872	2544
3	Wet	9.2	-	1296	1368
5	Wet	10.9	-	1056	1056
7	Average	6.4	144	2184	2760
9	Average	9.2	-	1584	1704
11	Average	10.9	-	1368	1368
13	Dry	6.4	168	2376	2760
15	Dry	9.2	168	1800	1872
17	Dry	10.9	-	1560	1560

procured amounts by strategic firms in equilibrium.

Now let's consider a fix hydro scenario, Wet. We find that increasing the price of natural gas from 6.4 $\$/MMBtu$ to 10.9 $\$/MMBtu$ reduces the difference between the socially-optimal import levels and the equilibrium volumes with strategic firms from 26% (High N. Eq.) to 0%. In other words, increasing the price of natural gas eliminates the incentives for firms to exercise market power in the three scenarios of hydro conditions considered in this study. We observe that this occurs because the socially-optimal level of imports is much more sensitive than the equilibrium outcome with strategic firms to a change in the price of natural gas. In the Wet scenario, increasing the price of natural gas from 6.4 $\$/MMBtu$ to 10.9 $\$/MMBtu$ reduces the socially-optimal volume of imports by 1488 hm^3, while the High N. Eq. only decreases by 816 hm^3.

We also find that Low N. Eq. only exist in a subset of scenarios, but the effect of natural gas prices and hydro conditions on aggregate import volumes is rather ambiguous. Take, for instance, the three cases with a natural gas price of 6.4 $\$/MMBtu$. In the scenario of Wet conditions, the aggregate procured volumes by strategic firms is 168 hm^3. In the scenario of Average hydro availability, these resources are more abundant than in the Wet scenario and strategic firms procure 144 hm^3 of natural gas, 24 hm^3 less than in the Wet scenario. However, in the scenario of Dry hydro conditions, the aggregate procured amount of natural gas in the Low N. Eq. is 168 hm^3, which is 24 hm^3 higher than in the Average scenario.

Table 4 shows annual generation per technology per year for the two strategic firms and the competitive firm. For simplicity, we only consider the Wet scenarios of hydro availability since changes in dispatch levels for the remaining cases are akin to the ones shown in this table. We only include gas and diesel generation because those are the two types of generation technologies that are most sensitive to changes natural gas import decisions of strategic firms.

We observe that, even under Wet hydro conditions, diesel units can be used for generation in the socially-optimal plan if natural gas prices are not low (cases

Table 4: Generation per technology for the strategic firms and the competitive fringe in GWh/year.

		Case 1			Case 3		Case 5
Firm	Technology	Low N. Eq.	High N. Eq.	S. Opt.	High N. Eq.	S. Opt.	S. Opt.
Firm 1	Gas turbines	381.1	6098	7749.6	5971	6352.1	4700.6
	Diesel	0	0	0	0	0	0
Firm 2	Gas turbines	482.8	3620.7	5428.8	844.8	844.8	844.8
	Diesel	180.6	0	0	453.7	391.2	657.5
Fringe	Gas turbines	11174.4	4105.3	762.8	4061.1	4030.8	4169.5
	Diesel	1341.7	0	0	2472.2	2185.9	3560.2

3 and 5). As we will see in the next section, the operation of these units gets reflected directly in the price of electricity. We also note that when strategic firms restrict their import volumes of natural gas, the SO increases the amount of power generated using gas turbines owned by fringe firms, with diesel units as a last choice for Low N. Eq. in Case 1. Nevertheless, for a medium price of natural gas (Case 3), the SO also relies on diesel units in the High N. Eq..

5.4. Effects of natural gas import decisions on electricity prices, profits, and total system costs

Table 5 shows load-weighted average electricity prices for the Low and High N. Eq. and for the socially-optimal levels of natural gas imports. Our first observation is that an increase in the price of natural gas has quite a large effect on electricity prices, profits, and total system costs, even under the socially-optimal levels of natural gas imports. For example, in the scenario of Wet hydro conditions, an increase in the price of natural gas from 6.4 \$/MMBtu to 10.9 \$/MMBtu yields a 163% increase in the average electricity price. However, if firms act strategically, the effect of a change in the price of natural gas on electricity prices is much smaller. In the High N. Eq., the same increase of the natural gas price results in a 70% increment of the average electricity price, from 55.4 \$/MWh to 94.4 \$/MWh. As discussed in Section, strategic firms have more incentives to exercise market power in scenarios of low than in scenarios of high natural gas prices. This feature explains why the model of central planning or price-taking firms is more sensitive to changes in the price of natural gas than the model of imperfect competition with strategic firms.

Table 6 shows total system costs for the socially-optimal import volumes of natural gas and welfare losses for the Low N. Eq. and High N. Eq. with respect to the socially-optimal outcome. Since we assume that the demand for electricity is perfectly inelastic, we measure welfare losses as the difference in total system cost between the outcome with strategic firms and the socially-optimal plan.

We find that welfare losses can be as high as 92.8% of total system costs if Low N. Eq. occur (Case 13), but they are at most 15.3% if strategic firms reach High N. Eq. (Case 1) in the open-loop equilibrium model. As expected, if Low N. Eq. do not occur, the highest largest welfare losses are achieved in scenarios of low natural gas prices (6.4 \$/MMBtu), because it is in those scenarios where we observe the largest increase in electricity prices under the High N. Eq. with respect to the social optimum.

Table 5: Load-weighted average electricity prices under imperfect competition and for the socially-optimal plan.

Case	Hydro	Gas price [$/MMBTtu]	Low N. Eq. [$/MWh]	High N. Eq. [$/MWh]	S. Opt. [$/MWh]
1	Wet	6.4	70.4	55.4	35.9
3	Wet	9.2	-	80.4	77.2
5	Wet	10.9	-	94.4	94.4
7	Average	6.4	87.9	55.5	36.0
9	Average	9.2	-	80.6	77.3
11	Average	10.9	-	94.5	94.5
13	Dry	6.4	107.2	55.9	36.2
15	Dry	9.2	107.2	81.2	77.9
17	Dry	10.9	-	95.3	95.3

Table 6: Welfare losses for the models with strategic firms and total system cost for the socially-optimal plan. We report welfare losses as the difference of total system cost between the models with strategic firms and the socially-optimal plan, measured as a percentage of the latter.

Case	Hydro	Gas price [$/MMBTtu]	Low N. Eq.	High N. Eq.	S. Opt. [$M]
1	Wet	6.4	80.4%	15.3%	867.7
3	Wet	9.2	-	2.5%	1283.9
5	Wet	10.9	-	0.0%	1479.6
7	Average	6.4	91.4%	12.3%	888.1
9	Average	9.2	-	4.2%	1268.5
11	Average	10.9	-	0.0%	1473.5
13	Dry	6.4	92.8%	7.9%	927.6
15	Dry	9.2	62.0%	2.5%	1283.1
17	Dry	10.9	-	0.0%	1478.6

Table 7 shows annual profits for the two strategic firms. Again, it is in the scenarios of low natural gas prices (6.4 $/MMBtu) and High N. Eq. when profits for strategic firms are much larger than under the socially-optimal import levels of natural gas. For instance, in Case 1, in the High N. Eq., Firm 1 earns 162.5% more profits than in the social optimum. However, in Case 2, Firm 1 only earns 6.5% more than in the social optimum.

Although we do not show them in the table, we also computed profits for all generation units in the fringe, for all the cases considered in this study. We found that all generators that are part of the competitive fringe ear higher profits when strategic firms exercise market power than under the socially-optimal plan. This means that, in our case study, all welfare losses are experienced by consumers that face electricity price spikes when strategic firms choose to restrict their import levels of natural gas. However, this is not a general result and it is possible that using a more detailed model, with less aggregated generation data

Table 7: Profits per firm for the models with strategic firms and for the socially-optimal plan. Profits for the models with strategic firms are reported as the difference between what firms get under the equilibrium in question versus what they would obtain in the socially-optimal plan, measured as a percentage of the latter. We only show the case numbers and omit the description of hydro scenarios and gas prices due to space limitations.

	Firm 1			Firm 2		
Case	Low N. Eq.	High N. Eq.	S. Opt. [$M]	Low N. Eq.	High N. Eq.	S. Opt. [$M]
1	213.8%	162.5%	179.4	210.6%	181.6%	181.9
3	-	6.5%	765.0	-	5.7%	655.8
5	-	0.0%	956.0	-	0.0%	861.2
7	349.1%	216.9%	158.0	351.9%	185.6%	155.7
9	-	7.0%	730.1	-	5.5%	639.5
11	-	0.0%	909.2	-	0.0%	848.0
13	481.7%	231.8%	149.8	516.5%	203.3%	140.7
15	22.2%	7.0%	709.2	37.2%	7.0%	626.9
17	-	0.0%	886.3	-	0.0%	836.6

and a more detailed transmission network, some units in the fringe could be worse off if strategic firms exercise market power through natural gas imports.

6. Conclusions

Market power is an important subject of research in electricity markets, particularly because of the lack of demand elasticity and the physical constraints present in power systems. Most of the existing literature on market power in electricity markets focuses on strategic bidding in wholesale bid-based markets. However, as demonstrated in Munoz et al. (2018), even in cost-based markets—where firms are not allowed to bid—firms might still be able to exercise market power in more subtle manners, such as choosing strategic investment portfolios.

In this article we contribute to the existing literature of equilibrium modeling with a new closed-loop model to study the potential incentives of generation firms to restrict contracted volumes of natural gas imports for electricity generation. This work is inspired by the current setting in the electricity market in Chile, where natural gas import decisions are made several months ahead of market operations.

We frame our closed-loop model of imperfect competition as an Equilibrium Problem with Equilibrium Constraints (EPEC), where strategic firms first commit to fixed import volumes of liquefied natural gas that become available later, in a perfectly competitive short-term electricity market. As it is well known in the operations research literature, EPECs can be very difficult to solve. However, since we focus on imports of liquefied natural gas transported by tankers in discrete quantities, we can map the full space of possible outcomes of the lower-level game, where the system operator determines optimal dispatch decisions and locational marginal prices in a cost-based electricity market. The discretization of the strategy space of strategic firms allows us to find all possible Nash equilibria of the game, which would not be possible employing other numerical techniques.

We use a simplified 9-node representation of the transmission system in Chile and assume that the two largest generation firms are strategic with respect to their import decisions of liquefied natural gas for electricity generation. As expected, we find multiple Nash equilibria that we group as High Nash Equilibria and Low Nash Equilibria. Our results indicate that, under certain scenarios hydro and natural gas prices, firms can have incentives to restrict the import volumes of liquefied natural gas by an average of 14% and 91%, approximately, with respect to the socially-optimal levels in the High N. Eq. and Low N. Eq., respectively. As we show in our results, these decisions can have very large impacts on electricity prices, total system costs, and profits for generation firms.

Nevertheless, the incentives to exercise market power through strategic import decisions are sensitive to the availability of hydro resources and the price of natural gas. We find that, out these two sensitivities, it is the price of natural gas in international markets that makes the largest difference. As the price of natural gas decreases, the socially-optimal volume of natural gas that would be procured by a central planner increases. Strategic firms also have incentives to increase their procured volumes of natural gas as its price decreases, but the magnitude of this change is much smaller than the one we observe in the scenario without strategic firms. We find that the largest deviations from the socially-optimal import levels occur for our scenario of a low natural gas price in international markets. In contrast, in the scenario of a high gas price, the socially-optimal plan belongs to the only set of Nash equilibria with strategic firms. As we point out in our discussions, this set of Nash equilibria is such that the sum of the import volumes for both strategic firms is approximately constant across all points in the set. These conclusions hold for the two types of contracts considered in this study, flexible and inflexible.

Of course, our study has several limitations that should be explored in future research; here we highlight two important ones. First, we disregard the existence of vertical arrangements or long-term contracts between generation firms and consumers. As demonstrated in Bushnell et al. (2008), generation firms that hold long-term financial positions have less incentives to exercise market power in wholesale markets than firms that only profit from their participation in the spot market. The model presented in this article could be extended to account for long-term contracts (e.g., as contract for differences) by including this information in the utility functions of strategic firms. While we do not address this question in our study, we hypothesize that, as in Bushnell et al. (2008), contracts could reduce the incentives of firms to restrict their import decisions of natural gas. In such case, the results presented in this article would provide an *upper bound* on the level of market power that firms could actually exercise in practice. However, we believe that the effectiveness of such contracts to reduce market power will be sensitive to the specifications of these long-term commitments. This is because, in congested transmission networks, the locational marginal price at the contractual point of delivery might not have a perfect correlation with the locational marginal prices faced by the generation units owned by a firm. Furthermore, some contracts can be indexed to electricity spot prices, which reduces the risk borne by generation firms if spot prices increase due to scarcity of natural gas.

A second main limitation of our study is the assumption of perfect forecasts about future demand levels, resource availability (e.g., hydro conditions), electricity prices, and dispatch levels. In reality, all of these factors are uncertain. Our results indicate that, under perfect information, the type of contract—flexible or inflexible–does not make much of a difference in terms of the incentives to restrict import volumes that result in higher electricity prices. However, we believe that, under uncertainty, the type of contract could make a large difference, particularly in cases where firms are risk averse. In such situations, we expect that the optimal import volume for a risk-averse firm that can engage in a flexible contract will be larger than the optimal volume for the same firm, but with the unique option of an inflexible contract with take-or-pay clauses. This type of behavior could make market monitoring very difficult, since market power is a market failure that could justify regulatory intervention. However, risk aversion is just a preference and not a market failure. If firms are risk averse, the only regulatory intervention that could be justified is to ensure that markets to trade risks have adequate levels of liquidity (de Maere d'Aertrycke et al., 2017).

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Appendix A. Case Study

Table A.8: Thermal limits of transmission lines in the 9-node network reduction of the main electric power system in Chile.

Transmission lines (node to node)	Capacity (MW)
CenterSIC - SICAncoa	2,806
NorthCenterSIC - CenterSIC	1,439
CenterSING - NorthCenterSIC	1,439
SICAncoa - SICCharrua	3,479
SICCharrua - SouthernSIC	2,028
NorthernSIC - NorthCenterSIC	715
CenterSING - SouthernSING	691
NorthernSING - CenterSING	473

Appendix A.1. Time-dependent data

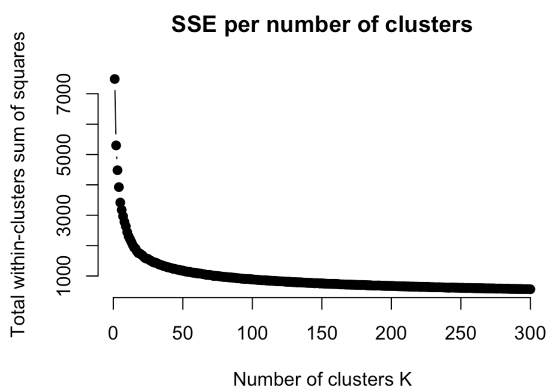

Figure A.8: Total within-clusters sum of squares versus number of clusters for the data set of demand, hydro, wind, and solar profiles.

Appendix B. Representative Nash equilibria

Table B.9: Import levels for firms 1 and 2 for each representative Nash equilibrium point and for the socially-optimal outcome. All values are in hm^3.

	Low N. Eq.		High N. Eq.		S. Opt.	
Case	x_1	x_2	x_1	x_2	x_1	x_2
1	72	96	1152	720	1464	1080
3	-	-	1128	168	1200	168
5	-	-	-	-	888	168
7	72	72	1344	840	1656	1104
9	-	-	1176	408	1224	480
11	-	-	-	-	888	480
13	72	96	1464	912	1656	1104
15	72	96	1152	648	1200	672
17	-	-	-	-	888	672

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