*Uluslararası Ekonomi ve Yenilik Dergisi*, 9 (2) 2023, 385-402

*International Journal of Economics and Innovation, 9* (2) 2023, 385-402

# Analyzing the Impact of Black Sea Gas Production on the Turkish Natural Gas Market with a Mixed Complementarity Problem Approach

*Araştırma Makalesi /Research Article*

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***ABSTRACT:*** *The discovery of natural gas in Black Sea has been a milestone for the Turkish natural gas market. This study examined the impacts of the Black Sea natural gas production on the Turkish natural gas market using a market equilibrium model, which is simulated with existing data from the Turkish natural gas market and solved using the GAMS software. The findings suggest that if global natural gas and oil prices remain as expected or stronger, Black Sea production will place downward pressure on end-user prices; however, if global market prices are lower than expected, natural gas will not be produced and will not impact the natural gas market under an oligopolistic market structure. Our model adds to the literature by offering an economic analysis of a gas production project through a market equilibrium modelling approach.*

**Keywords:** Turkish gas market, Black Sea gas production, market modeling, mixed complementarity problem.

**JEL Codes:** Q41, C61, C72.

# Karadeniz Gazı Üretiminin Türkiye Doğal Gaz Piyasasına Etkisinin Karışık Tamamlayıcılık Problemi Yaklaşımı ile İncelenmesi

***ÖZ:*** *Karadeniz'de gaz keşfi Türkiye doğal gaz piyasası için bir dönüm noktası olmuştur. Bu çalışmada Karadeniz gazının Türkiye doğal gaz piyasası üzerindeki etkisi bir piyasa denge modeli vasıtasıyla incelenmiştir. Bu model Türkiye doğal gaz piyasasının mevcut verileri ile çalıştırılmış ve GAMS yazılımı ile çözülmüştür. Elde edilen sonuçlara göre; küresel doğal gaz ve petrol fiyatları beklendiği gibi veya beklenenden yüksek olursa Karadeniz gazı üretimi son kullanıcı fiyatları üzerinde aşağı yönlü bir baskı oluşturacaktır. Buna karşın, eğer piyasa fiyatları beklenenin altında kalırsa, oligopol bir piyasa yapısında, Karadeniz gazı üretilmeyecektir ve doğal gaz piyasasını da etkileyemeyecektir. Bu model piyasa denge modeli vasıtasıyla bir doğal gaz üretim projesinin ekonomik analizinin yapılması boyutuyla literatüre katkı sağlamaktadır.*

**Keywords:** Türkiye doğal gaz piyasası, Karadeniz gazı üretimi, piyasa modelleme, karışık tamamlayıcılık problemi.

**JEL Codes:** Q41, C61, C72.

Geliş Tarihi / Received: 16/03/2023 Kabul Tarihi / Accepted: 22/09/2023

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## 1. Introduction

Turkiye has long been one of Europe's biggest natural gas importers having the fifth-biggest natural gas market (BP, 2020). Over the past decades, Russia, Azerbaijan, and Iran have been the countries satisfying Turkiye's natural gas requirement (approximately 45-50 bcm/year) through long-term natural gas supply contracts. Liquefied natural gas (LNG) contracts with Algeria and Nigeria have also bolstered the supply, and spot LNG has been procured for peak shaving purposes in winter periods. Turkiye's daily LNG regasification capacity increased from 37 to 117 mcm between 2018 and 2020 (BOTAS, 2020), allowing the country to better manage its natural gas and LNG imports. In 2020, Turkiye satisfied more than 50% of its natural gas demand from LNG in some months when the price was at a record low level (EMRA, 2021). Besides importing LNG, Turkiye is able to balance the daily fluctuations in demand using two underground storage facilities with a total capacity of 4 bcm (BOTAS, 2020).

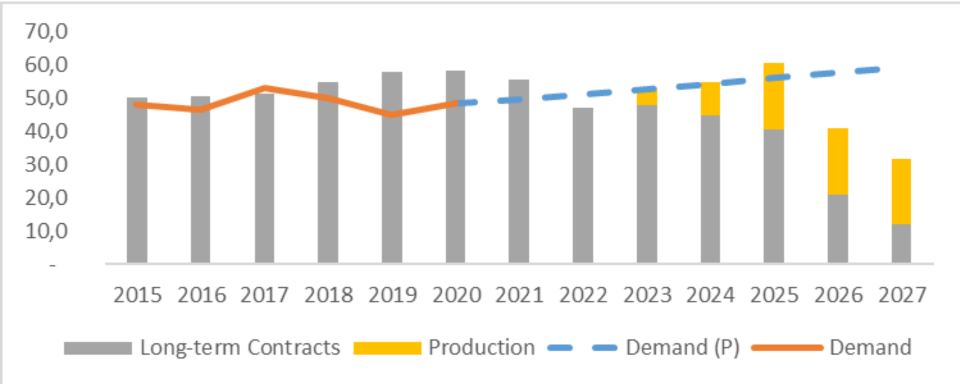
With the passage of the Natural Gas Market Law in 2001, Turkiye began the process of natural gas market liberalization. As of 2022, 80% of long-term supply contracts are held by BOTAS, and the remaining part is managed by seven private companies. Moreover, wholesale companies purchase gas and sell it to end-users. Since Turkiye's long-term natural gas supply contracts expire before 2026, the country must devise a strategy for meeting its future needs.

In September 2020, Turkiye discovered a gas reserve in the Black Sea Tuna-1 gas field with a volume of approximately 320 bcm, which was later updated to 405, 540 and 710 bcm respectively (Reuters, 2022). The timing of the discovery was perfect in that the gas production volume could be taken into account when designing Turkiye's natural gas strategy for the upcoming years. According to experts, production in the Tuna-1 gas volume will be between 2,5 bcm and 20 bcm starting from 2023 (Rystad, 2021). Figure 1 illustrates Turkiye's natural gas demand, contracts, and production. Whatever the production rate, this discovery will undoubtedly be a game-changer for the Turkish natural gas industry.

Analyzing the supply-demand balance and anticipating the impact of gas production is crucial in creating an optimum strategy for the Turkish natural gas market. In this context, a recent discussion has arisen: how the gas production will impact this market and to what degree end-user prices will be affected. Therefore, we believe that studies analyzing the Black Sea gas production from different perspectives will help policymakers and regulators concerned with Turkiye's future natural gas market.

In recent years, gas market analysis has received wide attention, and modelling tools have been applied for this purpose. One of these is complementarity modelling, which is mostly used to evaluate Europe's gas market liberalization. Mathiesen (1987) used this approach to analyze the market power of the European natural gas market. Golombek et al. (1995, 1998) focused on the impacts of liberalization, distinguishing upstream and downstream companies. Egging and Gabriel (2006) investigated the importance of infrastructure capacities using an equilibrium model. NATGAS (Zwart & Mulder, 2006) focused on the production phase of the natural gas market, and GASTALE (Boots et al., 2004) defined the structure of successive oligopoly in upstream and downstream phases. Lise et al. (2008) created a developed version of GASTALE, which incorporates transport capacity investment decisions. Holz et al. (2008) used GASMOD to address the European gas market in a successive oligopoly framework, while in another study, Abada et al. (2013) utilized GAMMES to analyze the European gas market considering fuel substitution cases. Valle et al. (2017) also developed a model to address the structure of the European gas market under the scenarios representing different maturity levels of a gas hub.

**Figure 1:** Supply-Demand Balance of the Turkish Natural Gas Market Between 2015-2027 (bcm)




Moreover, natural gas models have been used to investigate the supply-demand balance of gas markets under different supply scenarios. For instance, Lochner and Bothe (2007) analyzed the effect of the Nord Stream Pipeline, Lochner (2011) addressed the 2009 European Ukrainian gas conflict, and Dieckhoner et al. (2013) discussed the structure of the European gas market using the TIGER dispatch model. Egging et al. (2010) simulated the world gas market using the WGM model, and Chyong and Hobbs (2014) formulated the EPRG model to investigate the feasibility of the South Stream project. Holz et al. (2013) analyzed Europe’s infrastructure requirements; then Richter and Holz (2015) investigated the curtailment of Russian gas using the Global Gas Model. Kiss et al. (2016) created a model-based project evaluation method to evaluate shortlisted gas infrastructure investment proposals in Central and South-Eastern Europe. Toth et al. (2020) investigated the possible Russian gas export routes using the EGMM model.

While most of the research on gas markets focused on the European gas market, there are limited number of studies on the Turkish natural gas market structure. Biresselioglu et al. (2012) adopted a mixed integer programming model to determine an optimal strategy for Turkiye’s LNG supply. In another study, Biresselioglu et al. (2015) investigated the supply security of the Turkish natural gas market using principal component analysis. Hasanov (2017) examined the impact of import liberalization on the Turkish natural gas market using an economic modelling approach. Biresselioglu et al. (2019) collected private sector views of the restructuring process through an inquiry and applied a SWOT (Strengths, Weaknesses, Opportunities, and Threats) analysis to evaluate the liberalization of the Turkish natural gas market. Icik and Atak (2021) addressed the Turkish natural gas market structure in terms of pre-requisites to create a successful natural gas hub. And most recently, Icik and Atak (2022) analyzed the Turkish natural gas market's hub development process using a market equilibrium approach.

However, the reviewed studies lack an economic analysis of the gas production. In order to bridge this gap in the literature, we added the upstream segment to Icik and Atak's (2022) Turkish natural gas market model to analyze the impacts of Black Sea gas production under different market price scenarios. Based on the reference year 2019 and some assumptions, we simulated end-user prices under an oligopolistic market structure, which yielded several results. The contribution of our model to the literature is its detailed analysis on a gas production project using the market equlibirium modelling approach.

The rest of the paper is organized as follows. Section 2 gives a brief summary of the theory and describes our model, including assumptions and scenarios. Section 3 presents the data used to simulate our model and gives the obtained results and relevant discussions. The last section provides a summary of the value of this study and anticipated future work.

## 2. Materials and Methods

### 2.1. Mixed Complementarity Problems

Mixed complementarity problems (MCPs) are used to build policy models to analyze the markets and make suggestions about pricing and regulations (Murphy et al., 2016). These models have been extensively used to simulate equilibrium conditions of natural gas markets and suggest market structure design policies for them (e.g., Golombek et al., 1995; Boots et al., 2004; Gabriel & Smeers, 2006, etc.). Due to the wide usage of MCP in natural gas market modelling, it was used in this study to analyze the equilibrium conditions of the Turkish natural gas market.

An MCP is formed by Karush-Kuhn-Tucker (KKT) conditions and used to formulate non-linear problems having inequality constraints, and market clearing conditions. The MCP is formulated as given below (Bazaraa et al., 1993):

Given a function F: $R^n \rightarrow R^n$ and vector x $\in R^n$

$F_i(x) = 0$ and $l_i \leq x_i \leq u_i$

$F_i(x) > 0$ and $\mathrm{x}_i = \mathrm{l}_i$

$F_i(x) < 0$ and $\mathrm{x}_i = \mathrm{u}_i$

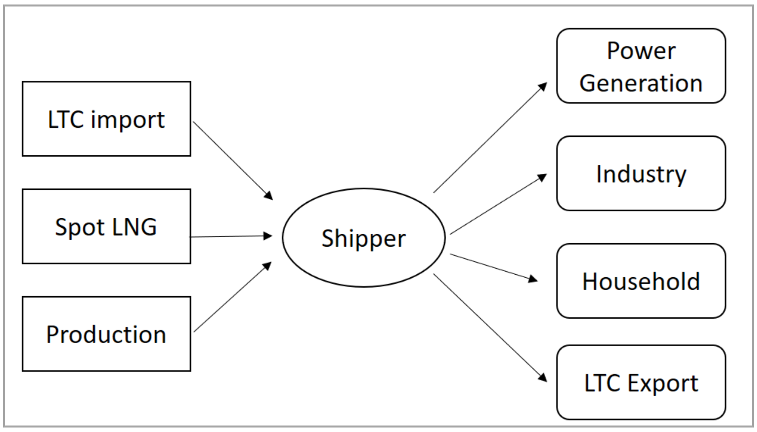
where $\mathrm{l}_i$ and $\mathrm{u}_i$ represent lower and upper bounds respectively for the parameter $\mathrm{x}_i$.

The structure of a natural gas market can be defined by an MCP formulation since each market player maximizes their profit while being constrained by maximum capacities and minimum quantity obligations (Egging et al., 2010). Considering that MCPs can be solved using the GAMS software (Rutherford, 1995), we implemented PATH 5.0 algorithm on the GAMS software to solve our model. The problem's convexity ensures that the KKT optimality conditions are both necessary and sufficient.

### 2.2. Model Description

This study modelled the Turkish natural gas market through the shippers' profit maximization problem while omitting the transmission, underground storage, and LNG operator's problems. Since long-term contracted (LTC) natural gas prices are recalculated quarterly by pricing formulas, we used a quarter for this analysis. In the Turkish natural gas market, a shipper is a group that can either import gas or buy it from an importing company and sells it to the power generation, industry, and household sectors or export it (Figure 2). Each shipper maximizes its profit by deciding on the natural gas quantity to buy/import and sell to end-users under several constraints.

**Figure 2:** Structure of the Turkish Natural Gas Market




The shippers' optimization problem is given by:

$$\mathrm{Min} \sum_p (p_p^h\,(q_{sp}^h).\,q_{sp}^h + p_p^i(q_{sp}^i).\,q_{sp}^i + p_p^p\,(q_{sp}^p).\,q_{sp}^p + p_{sp}^{ex}.\,q_{sp}^{ex} - p_{sp}^{pg}.\,q_{sp}^{pg} - c_{sp}^n\left(q_{sp}^n\right) - p_{sp}^{lng}.\,q_{sp}^{lng})\ \forall\, i \qquad (1)$$

where $q_{sp}^h, q_{sp}^i, q_{sp}^p$ are quantities offered by shipper s in the period p which represents a quarter of the year and, $p_p^h$, $p_p^i$, $p_p^p$ are end-user prices in the period p for the household, industry, and power generation sectors, respectively. Our model assumed that a shipper could procure gas by buying spot LNG and production gas besides the LTC importation option. Natural gas export is assumed to be carried out by the incumbent company (S3) as in the current situation of the Turkish natural gas market. In our model, $p_{sp}^{lng}$, $p_{sp}^{pg}$, $p_{sp}^{ex}$ are prices and $q_{sp}^{lng}$, $q_{sp}^{pg}$, $q_{sp}^{ex}$ are quantities for spot LNG, production gas, and LTC export, respectively. Furthermore, LTC natural gas supply cost and quantity are represented by $c_{sp}^{ng}$ and $q_{sp}^{ng}$. The shippers' problem is constrained with Eqs. (2-6).

$$\sum_p q_{sp}^{ng} \leq Q_s^{ng} \ \forall s \tag{2}$$

$$\sum_p q_{sp}^{ex} \leq Q_s^{ex} \ \forall s \tag{3}$$

$$T_s^{ng} \leq \sum_p q_{sp}^{ng} \ \forall s \tag{4}$$

While $Q_s^{ng}$ and $Q_s^{ex}$ are the long-term contract's maximum available quantity per year for the natural gas import and export quantities, $T_s^{ng}$ represents the minimum annual quantity (MAQ) for a shipper.

$$q_{sp}^{lng} \leq Q_{sp}^{lng} \tag{5}$$

$$q_{sp}^{pg} \leq Q_{sp}^{pg} \tag{6}$$

$Q_{sp}^{lng}$ and $Q_{sp}^{pg}$ represent the capacity for spot LNG and natural gas production for the period p and shipper s. The non-negativity of variables is ensured by Eq. (7).

$$q_{sp}^{h}, q_{sp}^{i}, q_{sp}^{p}, q_{sp}^{lng}, q_{sp}^{pg}, q_{sp}^{ex} \geq 0 \ \forall sp \tag{7}$$

Shippers' balance constraint is given in Eq. (8), which ensures that all inputs of a shipper are equal to outputs in a period.

$$q_{sp}^{ng} + q_{sp}^{lng} + q_{sp}^{pg} = q_{sp}^{h} + q_{sp}^{i} + q_{sp}^{p} + q_{sp}^{ex} \ \forall sp \tag{8}$$

We assumed in this study that the Turkish gas market's equilibrium prices are formed by shippers' preferences and demand response in the market. Therefore, the demand-price interaction is reflected by the following linear inverse-demand functions for household, industry, and power generation sectors where $\gamma$ is the intercept of the function, whereas $\alpha$ represents slope (Eqs. 9-11).

$$p_p^h = \gamma_p^{h0} - \sum_s \propto_{sp}^h q_{sp}^h \ \forall p \tag{9}$$

$$p_p^i = \gamma_p^{i0} - \sum_s \propto_{sp}^i q_{sp}^i \ \forall s \tag{10}$$

$$p_p^p = \gamma_p^{p0} - \sum_s \propto_{sp}^p q_{sp}^p \ \forall p \tag{11}$$

LTC natural gas supply cost is formulated as in Eq. (12).

$$c_{sp}^n(q_{sp}^n) = p_{sp}^n \cdot q_{sp}^n \ \forall sp \tag{12}$$

### 2.3. Model Data, Assumptions, and Scenarios

Since we aim to simulate the Turkish natural gas market structure and end-user prices, we used current data and predicted future values based on several assumptions regarding future scenarios.

The 2019 quarterly sectoral natural gas consumption (EMRA, 2020) and price data (BOTAS, 2019) were used to calibrate our inverse-demand function parameters, as shown in Table 1. The explanation for using 2019 as the reference year rather than 2020 or 2021 is that the latter years would not accurately represent market conditions because the COVID-19 pandemic and natural gas crisis affected the entire supply-demand balance in those years. Statistical data from the Central Bank of the Republic of Turkiye were used to convert USD[2] to TRY[3] (TCMB, 2021). Furthermore, to calibrate our model, we assumed that the price elasticity of demand is 0,93, taken from Golombek et al. (1995) as results produced by our model using this elasticity match the actual end-user prices and consumption in our reference year.

**Table 1:** Reference Year Data

| Periods | consumption (bcm) | | | prices (USD/1000 $sm^3$) | | |
|---|---|---|---|---|---|---|
| | power generation | industry | household | power generation | industry | household |
| q1 | 2,67 | 3,91 | 9,76 | 289 | 252 | 166 |
| q2 | 2,00 | 3,54 | 3,53 | 264 | 230 | 152 |
| q3 | 3,26 | 3,57 | 1,17 | 288 | 262 | 188 |
| q4 | 3,31 | 3,94 | 4,27 | 277 | 268 | 216 |

Traditional long-term natural gas contract prices are calculated based on the formulas influenced mainly by Brent prices (Cohen, 2019). Although natural gas import prices are confidential information, LTC natural gas prices can be roughly calculated using a 12% Brent slope as given in the literature (Steuer, 2019). Therefore, we calculated the monthly price of a long-term natural gas supply contract in 2023 by multiplying the nine-month average of ICE Brent futures by 12% (ICE, 2021a). Furthermore, since no public data on Turkiye's natural gas export price formula is available, we assumed that the price would be higher (+10 USD/1000 $sm^3$) than the LTC natural gas import price.

The spot LNG supply price is another significant input to our model. In recent years, European delivery spot LNG transactions have been carried out using TTF as the benchmark price index (Liao and Sykes, 2019). As a result, we assumed that spot LNG could be supplied at a price equal to TTF and calculated using ICE TTF futures month ahead prices for the year 2023 (ICE, 2021b). Table 2 lists all import and export prices we used in the model.

[2] United States Dollar
[3] Turkish Lira

The most crucial assumption we made in this study is the break-even price for natural gas production, which can vary from 0,5 to 4,5 USD/MMBtu depending on the resource specifications (Steuer, 2019). We assumed the cost of producing gas to be 3,25 USD/MMBtu, the average price forecast made by Rystad Energy (2021).

**Table 2:** Prices Used in the Model

| Periods | Spot LNG price USD/1000 $sm^3$ | LTC import price USD/1000 $sm^3$ | LTC export price USD/1000 $sm^3$ |
|---|---|---|---|
| q1 | 225 | 226 | 236 |
| q2 | 191 | 225 | 235 |
| q3 | 181 | 224 | 234 |
| q4 | 203 | 223 | 233 |

Our model is constrained by shippers' contractual obligations and the physical capacities of the natural gas transmission grid. Shippers' annual available long-term contract quantities are determined under the assumption that Turkiye's expiring long-term contracts will not be renewed (BOTAS, 2020). The minimum annual quantity, which is shippers' obligation to offtake natural gas from their LTC suppliers, is assumed to be 80% of annual contract quantities since traditional long-term supply contracts have an MAQ percentage of about 70-80% (Cohen, 2019).

In this study, we assumed that there are three shippers in the market: the shipper having no contractual obligations (S1), the shipper having limited contractual obligations (S2), and the incumbent company having huge contractual obligations (S3). Our assumptions regarding shippers' annual contract quantity (ACQ) and minimum annual contract quantity are presented in Table 3.

**Table 3:** Shippers' Contractual Quantities

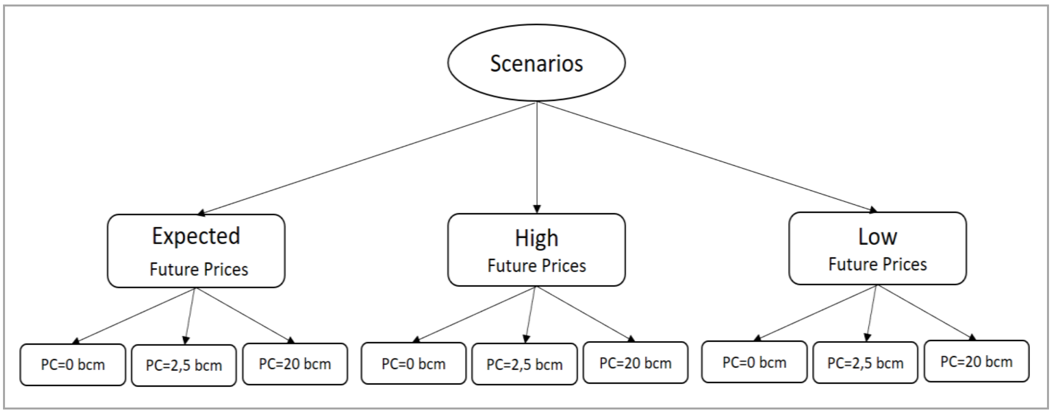
| Shippers | ACQ bcm | MAQ bcm |
|---|---|---|
| S1 | 0 | 0 |
| S2 | 6 | 4,8 |
| S3 | 37,6 | 30,08 |

Assuming Turkiye offtakes 1,5 bcm LNG from the Algeria long-term contract[4] per quarter (BOTAS, 2020), by subtracting this quarterly amount from the total quarterly LNG capacity, which is determined by multiplying daily send-out capacity (117 bcm) by 90 days (BOTAS, 2020), we arrive at a quarterly idle LNG send-out capacity of 9,03 bcm, which can be used for offtaking spot LNG. Moreover, since BOTAS already exports natural gas, the export contract amount (0,75 bcm/year) is used in the calculations (BOTAS, 2020).

[4] Turkey's Algeria LNG supply contract quantity is 6 bcm/year (Rzayeva, 2018)

In this study, we created three main scenarios for different levels of future prices: (i) Expected Future Prices (EFP), (ii) High Future Prices (HFP), and (iii) Low Future Prices (LFP). For the EFP scenario, we used ICE month-ahead contract prices, which were increased by 50% in the HFP scenario and decreased by 50% in the LFP scenario (Figure 3). Furthermore, we created sub-scenarios under the main scenarios by adjusting natural gas production capacity (PC) from 0 to 2,5 and 20 bcm since Turkiye's annual gas production is expected to be in the range between 2,5 and 20 bcm (Rystad Energy, 2021).

**Figure 3**: Scenarios




## 3. Results and Discussion

This section presents our simulation results and discussion on the market structure and end-user prices under the aforementioned scenarios.

### 3.1. Expected Future Prices Scenario

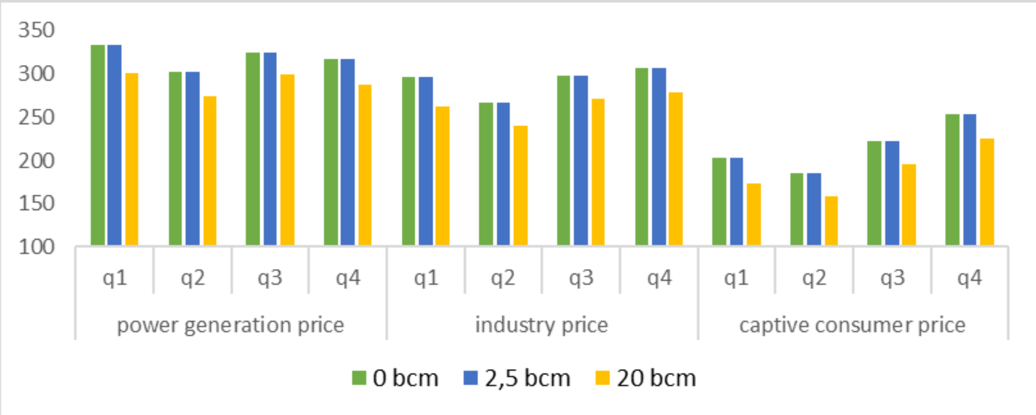
#### 3.1.1. PC = 0 bcm

In this sub-scenario, S2 and S3 shippers fulfill their contractual obligations by offtaking the MAQ of their long-term contract, opting not to offtake spot LNG in order to prevent end-user prices from decreasing below the optimum value. However, the shipper without a long-term contract (S1) offtakes 3,5 bcm of spot LNG and sells it only to the power generation and industry sectors since household users' sales prices remain low relative to spot LNG prices. For the power generation, industry, and household sectors, total natural gas consumption is 37,7 bcm, and end-user prices are 320, 292, and 216 USD/1000 $sm^3$, respectively. Under this sub-scenario, shippers make a profit of 1,73 billion USD due to their sales and purchase activities.

#### 3.1.2. PC = 2,5 bcm

Although a new natural gas source comes online in this sub-scenario, the total natural gas entry to the market does not change since shippers opt to decrease spot LNG imports by the amount of produced gas in order to optimize their import quantities. In addition to spot LNG and production gas, long-term contract holders import the MAQ of their contract to satisfy the Turkish natural gas market demand. Since the overall quantity of gas supply remains constant, total demand and end-user prices remain unchanged from the previous sub-scenario. However, in this sub-scenario, shippers' overall profit rises to 1,93 billion USD due to an improvement in S1's profit as a result of replacing spot LNG with production gas, which lowers gas supply costs.

**Figure 4:** End-User prices with regard to Varying PC under "Future Prices" scenario (USD/1000 $sm^3$)




### 3.1.3. PC = 20 bcm

In the case that Black Sea gas is produced with an annual capacity of 20 bcm, S1 and S2 shippers purchase a total of 9,1 bcm production gas throughout the year in addition to the MAQ obligation of their long-term contract. At the same time, S1 uses the advantage of not having contractual obligations and purchases most of the produced gas that primarily enters the market in the first quarter when the natural gas consumption is at its peak for the year. The quantity of purchased production gas (9,1 bcm) shows us that shippers' optimization might result in lower production than the maximum capacity of natural gas production (20 bcm).

In this sub-scenario, increasing natural gas production triggers a rise in consumption (43,3 bcm) and a drop in end-user gas prices. Most remarkably, natural gas prices decrease by 11,4%, 12,5%, and 16,6% on an annual average in the power generation, industry, and household sectors, respectively, thanks to the cost-lowering effect of Black Sea gas production (Figure 4). Furthermore, although the profit of S1 increases due to the low-cost production gas, decreasing end-user prices pulls down the profit of S2 and S3; consequently, the total profit of shippers drops from 1,7 to 1,53 billion USD.

## 3.2. Low Future Prices Scenario

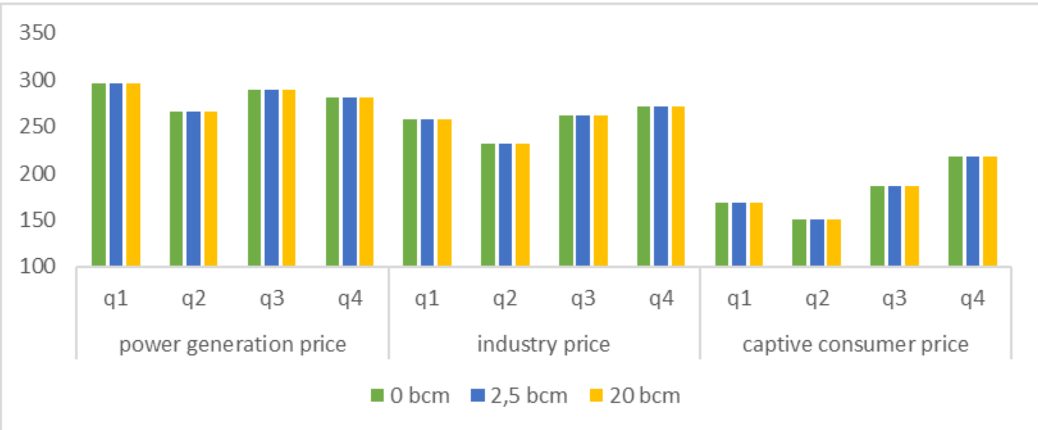
### 3.2.1. PC = 0 bcm

If PC equals zero, natural gas is consumed (44,6 bcm) more than the EFP scenario since low-cost spot LNG can enter into the market. Also, Spot LNG import reaches 10,4 bcm while shippers offtake the MAQ of their LTC gas contracts. Due to low natural gas supply prices, end-user prices in the power generation, industry, and household sectors are lower in this scenario than in the EFP scenario by 11,4%, 12,5%, and 16,6% respectively on an annual average. Furthermore, while low prices do not directly benefit end-users, they do benefit shippers by lowering their average cost of natural gas provision. As a result, relative to the EFP PC=0 sub-scenario, shippers' gross profit leaps from 1,73 to 5,38 billion USD.

### 3.2.2. PC = 2,5 bcm

In this sub-scenario, 2,5 bcm of Black Sea annual gas production capacity is assumed to be available. Shippers meet their long-term contract commitments and offtake 10,4 bcm of spot LNG, which is the same volume as the previous sub-scenario. Black Sea production gas cannot penetrate into the market because after fulfilling the contractual obligations, the cheapest gas supply option is spot LNG in all quarters. Therefore, if spot LNG prices are lower than the cost of Black Sea gas production, shippers prefer purchasing spot LNG until the quantity reaches 10,4 bcm. Assuming Turkiye has a yearly LNG capacity of almost 36 bcm, there is no need for a different natural gas source other than LTC natural gas and spot LNG if spot LNG prices are low. Since the market structure does not change in this scenario, end-user prices, natural gas consumption, and shippers' profit do not differ from the previous sub-scenario (Figure 5).

**Figure 5:** End-User Prices with Regard to Varying PC Under "Low Prices" Scenario (USD/1000 $sm^3$)




### 3.2.3. PC = 20 bcm

If Black Sea gas production starts with an annual capacity of 20 bcm, shippers still prefer to offtake the MAQ of their long-term contract and 10,4 bcm of spot LNG and not purchase production gas. While S1 purchases LNG in all periods, S2 purchases it in q2 and q3 when spot LNG prices are relatively lower compared to other quarters. Production gas cannot enter the gas market in this sub-scenario either. Moreover, end-user prices, natural gas consumption, and shippers' profits under this sub-scenario do not differ from the previous sub-scenarios.

### 3.3. High Future Prices Scenario

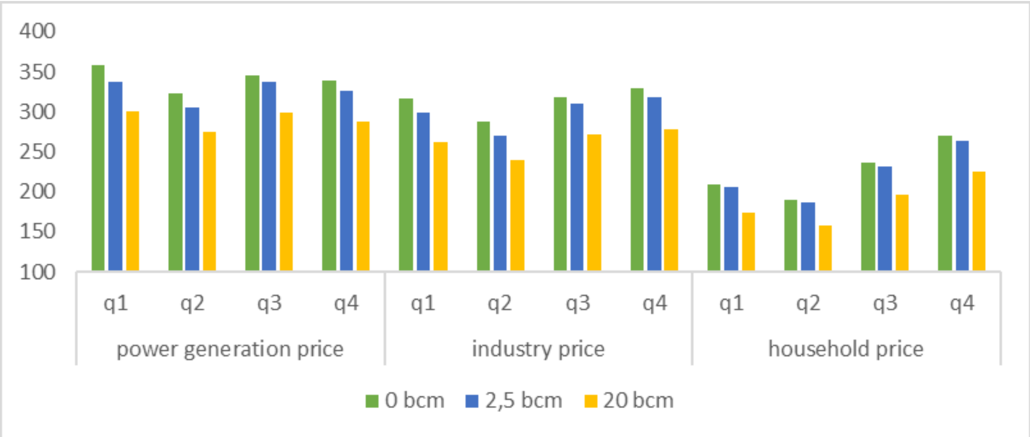
#### 3.3.1. PC = 0 bcm

Since LTC natural gas and spot LNG prices are higher than in previous scenarios, end-user prices in this sub-scenario are 6,7%, 7,1%, and 4,5% higher on an annual average for the power generation, industry, and household sectors, respectively, than in the EFP scenario. While S2 and S3 offtake the MAQ of their contract, S1 purchases an additional 834 mcm spot LNG throughout the year. As a result of these, annual gas consumption reaches 34,9 bcm. In this sub-scenario, S2 and S3 sell the gas at a loss since contract prices are higher than end-user prices in all periods. However, since S1 does not have any offtake obligation, it sells gas in the periods when the end-user prices are higher than the spot LNG price. As a result, the profit of S1 drops, whereas S2 and S3 are compelled to bear a great loss, resulting in a total loss of 1,85 billion USD for all shippers.

#### 3.3.2. PC = 2,5 bcm

In this sub-scenario, low-cost production gas enters the market in full capacity. S1 purchases 2,5 bcm of the production gas, whereas S2 and S3 offtake the MAQ of their contract, preventing spot LNG from entering the market. The introduction of cheap production gas increases the natural gas consumption from 34,9 to 36,6 bcm and lowers the annual average of end-user prices by 4,3%, 4,5%, and 1,7% for the power generation, industry, and household sectors, respectively (Figure 6). Owing to low-cost production gas purchased by S1, its profit increases, and the shipper's total loss decreases from 1,85 to 1,77 billion USD.

**Figure 6**: End-User Prices with Regard to Varying PC Under "High Prices" Scenario (USD/1000 $sm^3$)

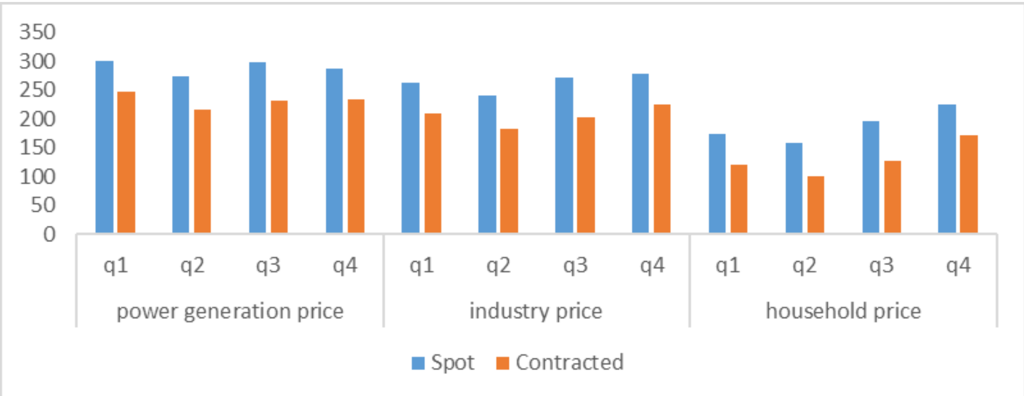


### 3.3.3. PC = 20 bcm

If the production gas enters into the market with 20 bcm of total capacity in the HFP scenario, shippers purchase 9,1 bcm production gas in addition to the MAQ of LTC gas, and spot LNG cannot enter into the market in this sub-scenario either. Having the advantage of not holding a long-term contract, S1 purchases 6,9 bcm of production gas, while S2 purchases the remaining 2,2 bcm. As a result, total natural gas consumption reaches 43,2 bcm, and natural gas end-user prices decrease on annual average by 15%, 16%, and 17% in the power generation, industry, and household sectors, respectively. Increasing sales quantities and decreasing end-user prices cause a rise in shippers' loss to 2,31 billion USD.

In the above scenarios, we assumed that Black Sea gas would be produced, depending on the spot market conditions. However, if the Black Sea gas is produced in full capacity regardless of market conditions, end-user prices decrease on annual average by 27%, 30%, and 40% in the power generation, industry, and household sectors, respectively (Figure 7). This picture is the result of obligations arising from production and import contracts. Since the end-user prices plunge below the level that shippers are willing to sell natural gas under the assumption that production gas is purchased in full amount, the shipper's losses increase in either future, high or low prices scenarios. On the other hand, if spot natural gas export options are developed in the Turkish natural gas market, shippers might be willing to purchase greater capacity of production gas to the extent that they can export. Therefore, we should note that our calculations in this study are based on the assumption that there is no spot natural gas export option for shippers in the Turkish natural gas market.

**Figure 7:** Comparison of Spot or Contracted Cases of Production under EFP (USD/1000 sm$^3$)




## 4. Results and Discussion

This study analyzed the impact of the Black Sea gas production on the Turkish natural gas market under different market price scenarios. This analysis is based on the assumption of an oligopolistic market structure even though, currently this is not the case in the Turkish natural gas market. A market equilibrium model was adopted to simulate shippers’ profit maximization problem. Our model was calibrated using the reference data for the base year 2019, whereas we used the future contract prices of Brent and TTF to anticipate the cost of LTC natural gas and spot LNG. We created three main scenarios to provide insight into the effects of Black Sea gas production on the Turkish natural gas market under different market price scenarios: (i) Expected Future Prices, (ii) Low Future Prices, and (iii) High Future Prices. Under these scenarios, we adjusted production capacity from 0 to 2,5 and 20 bcm in the sub-scenarios to discuss the effects of different volumes anticipated to be produced. We arrived at a Mixed Complementarity Problem structure by combining KKT conditions from the shippers' maximization problem with market-clearing conditions and solved the problem with the GAMS PATH algorithm.

Our results assert that market prices are the main indicator of the Black Sea gas production’s feasibility. When the market prices are as expected or high, production gas can penetrate the market and put downward pressure on end-user prices. However, if market prices are lower than the cost of producing gas, Black Sea gas cannot penetrate the market and impact end-user prices, according to the Low Future Prices scenario.

We found that, in the Expected Future Prices scenario, if gas production with a capacity of 2,5 bcm comes online, it would replace spot LNG imports and have no impact on overall demand or end-user prices. However, when production capacity increases to 20 bcm, the average end-user price drops more than 11% on an annual average. We discovered that a production capacity of 2,5 bcm could only impact market prices if market prices are 50% higher than expected. Moreover, the effect of increasing production capacity to 20 bcm is also more severe in the High Future Prices scenario compared to the Expected Future Prices scenario as the average end-user prices drops more than 15%. Although gas production triggers the drop of end-user prices in the Expected Future Prices and High Future Prices scenarios, it cannot impact end-user prices when the market prices are low in the Low Future Prices scenario.

Another significant finding of this study is that, regardless of market prices, maximum 9,1 bcm of Black Sea gas can enter the market annually in an oligopolistic structure due to the strategic withholding of shippers in the domestic market. Lower consumption results in lower production than availability, limiting the drop in end-user prices. However, if we assume that production gas penetrates the market regardless of market prices, the average price of end-users drops more than 27% on an annual average. Furthermore, we believe that expanding Turkiye's spot natural gas export options will favor shippers when Black Sea gas production begins, as shippers will be more likely to sell gas to other countries rather than the domestic market since they are price-takers in global natural gas market.

We can without any doubt conclude that Black Sea gas production will have a remarkable positive effect on the Turkish natural gas market. This result is consistent with the prior studies contending that natural gas infrastructure development results in decreasing prices. The decision whether to produce the natural gas on an LTC or spot basis will affect the result of who will benefit from the production gas most: shippers or end-users. Furthermore, in an oligopolistic market, shippers will optimize their import quantities to gain the maximum benefit, and production capacity will be the principal determiner of this benefit's extent.

This study can be extended by including a more detailed representation of sectoral elasticities as they are the main parameters affecting all the results. Moreover, since we assumed that one shipper of each category is competing in the market, the impact of the number of shippers can be further investigated by simulating the model with different number of shippers from each category. On the other hand, our Turkish natural gas market model can be further developed by the addition of other market activities, such as transmission and underground storage.

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