# The Southern Gas Corridor and its Importance for South-East Europe

## The New Era of Energy Transition


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# Executive Summary

Over recent years, the European Union has been increasingly exploring new alternative routes and sources for natural gas due to energy security concerns, mostly associated with the Russian-Ukrainian circumstances and the significant role which natural gas is expected to have in the future. Currently it is considered as the 'transition fuel' to the future green-energy reality. The so-called Southern Gas Corridor (SGC) is one of the most significant alternative routes and after years of planning its estimated completion date is rapidly approaching. Considerable progress has been shown towards the completion of this major project; some challenges, including regional security issues, local opposition along parts of the route, stagnant demand in Western Europe and the consistently decreasing cost of imported Liquefied Natural Gas (LNG), still remain.

In this context, this book has invited a series of experts in the field to discuss, in detail, the current state of the SGC, elaborate on the challenges and opportunities that lie ahead and investigate possible geopolitical and economic implications. The book consists of 11 distinct Chapters, each one focusing on a different aspect of the global gas and LNG markets, in respect to the SGC and the wider South-Eastern (SE) Europe region. These aspects include the discussion regarding the need for a decarbonized European Union, the security of supply issue, the role of several countries in the SE Europe region and the potential imports from non-EU countries.

Chapter 1 provides an overview of the current global natural gas and LNG markets. First of all, the main characteristics of natural gas as a fuel are introduced and details of the whole natural gas supply chain from the point of exploration and production until final consumption are presented. Then, the current global status of natural gas markets and transactions are described, and emphasis is given to the European region. The main gas infrastructure of the region (pipeline networks, LNG terminals and storage facilities) are presented.

Chapter 2 presents the vision of the EU for a new decarbonized Europe and provides some details of the framework and international negotiations that are currently defining the EU countries. Besides, the Chapter includes an analysis of the implemented energy policies to achieve the long-term climate goals. Moreover, it illustrates that, despite the increased penetration of Renewable Energy Sources (RES) in the energy mix, there are still some security of supply and balancing issues. Those concerns can potentially identify the use of natural gas as the 'transition fuel' during the transformation of the EU's energy mix.

Chapter 3 aims to deliver a country-level analysis of SE gas market and prices. In detail, this Chapter presents natural gas quantities used in SE countries by sectorial end-use, the evolution of gas prices and the latest trends regarding

LNG and pipeline gas imports. A comparison of various metrics among the countries is conducted and potential geopolitical implications from gas use are discussed.

Chapter 4 provides detailed data regarding the current and estimated natural gas production levels of Azerbaijan. Furthermore, the Chapter investigates the potential gas quantities that the country may have available, and eligible for export, both short-term and long-term.

Chapter 5 analyses the significance of SGC within the larger context of EU Gas Security Strategy and its potential link with the Eastern Mediterranean. It also illustrates the importance of SGC for the energy security of Greece. Moreover, it highlights the development opportunities created for the SE EU gas markets from the construction of TAP and new “adjunct” infrastructure. Namely, the Interconnector Greece-Bulgaria (IGB) pipeline, while focusing on the way the completion of the project affects the overall energy policy of Greece.

The case of Italy as a ‘Gas Pioneer’ is presented in Chapter 6. All historical landmarks, starting from World War 2, related to the development of the Italian natural gas sector are reviewed. This Chapter explores all the policies followed by the Italian governments throughout the years that made Italy one of the most gas-friendly countries of the region.

Chapter 7 provides a summary of the current situation of the natural gas market in Bulgaria. A brief historical review illustrates the course of natural gas in Bulgaria throughout the years. Besides, the Chapter presents the details of the domestic market’s size, sources of supply, physical infrastructure and legal framework. In addition, the impact of SGC on Bulgaria is explored and the importance of the country’s gas market to the wider regional dynamics in terms of gas and energy trade is highlighted.

Next, Chapter 8 presents the current status of the natural gas market in Turkey and focuses on the country’s potential to be upgraded from a regional gas transit country to a natural gas hub. The completion and commissioning of major infrastructure projects will significantly increase the volume and capacity of Turkey’s domestic gas market. The liberalisation of the legal framework is expected to contribute to the potential generation of a ‘Gas Hub’ in Turkey.

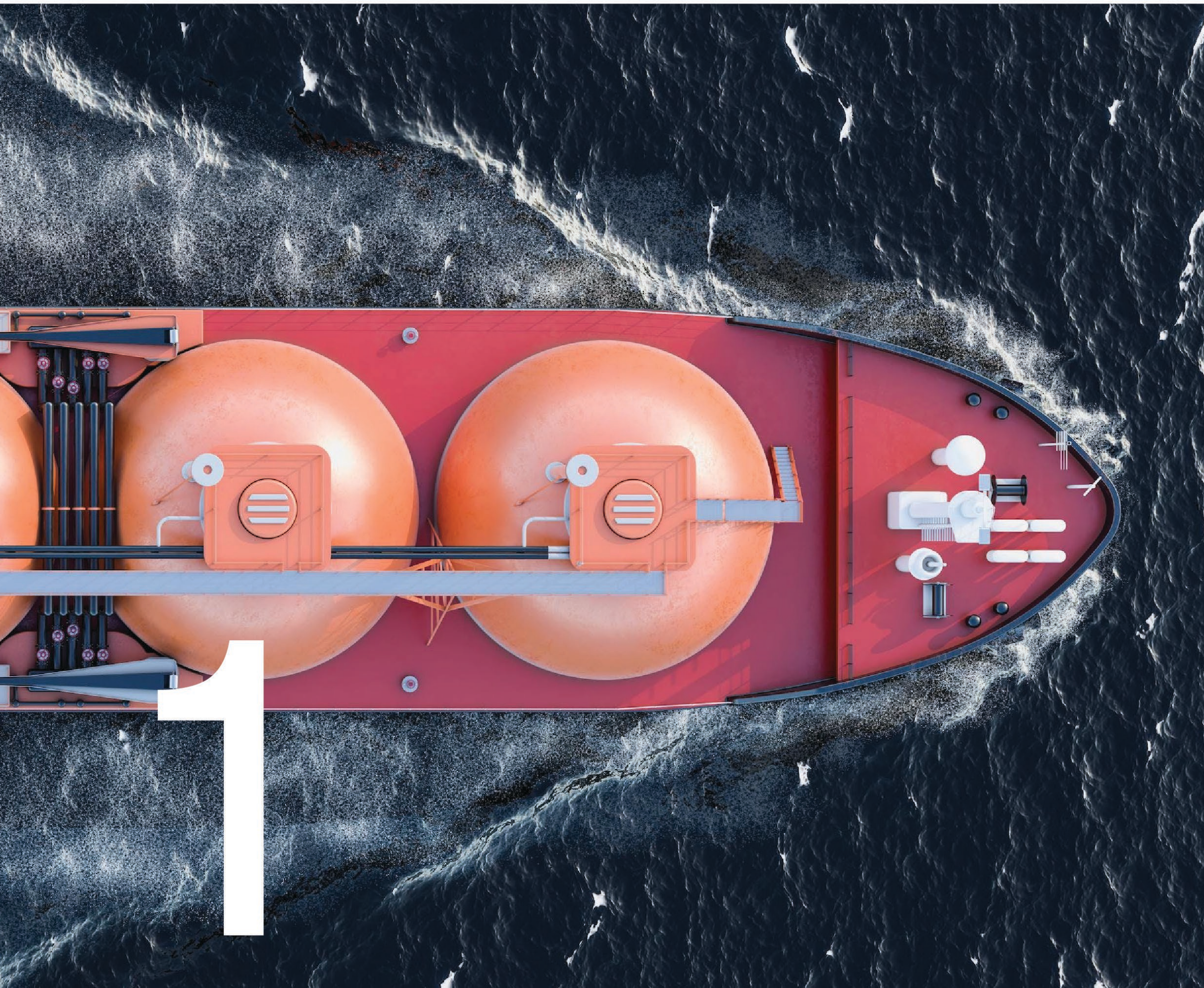
The gas export potential of Iraq to the EU through SGC is illustrated in Chapter 9. Iraq’s excess gas resources are undeniable, but severe problems regarding their development and export capability make the transportation of Iraqi gas to Turkey and the EU extremely difficult. The current state of the natural gas market is discussed and estimates of the potential Iraqi gas export are presented.

Chapter 10 shifts the focus from SE Europe to the wider European region. In particular, the Chapter discusses on another pipeline project, Nord Stream 2, that demonstrates a close interconnectivity between economic, political and legal issues. This project has raised intense discussions and confrontations within EU circles. The aim is to summarize German – Russian Gas relations and analyse the implications of the project.

Finally, given the increasing importance of natural gas and its implications as described in the above sections, Chapter 11 attempts to describe the basic gas and oil cost mechanisms. More specifically, it reveals the correlation between oil and natural gas prices using calculation formulas and investigates the global oil price behaviour over the recent years.

Chapter 1

# An overview of the SE European Gas Markets and LNG Prospects



# 1. An Overview of the SE European Gas Markets and LNG Prospects

by Dr. Kostas Andriosopoulos[1]

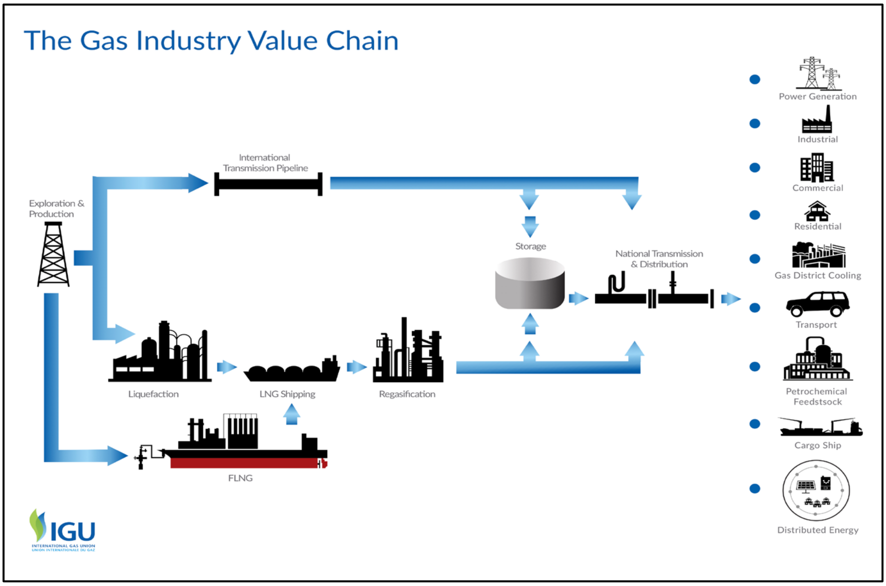
## 1.1 Introduction to natural gas

Much discussion has taken place in past years on the role of natural gas in the energy mix. Natural gas is a hydrocarbon produced in a similar way to other hydrocarbons such as oil. Its main component is methane, but it also contains in very small portions other alkanes, such as ethane, propane, butane, as well as carbon dioxide, nitrogen, water vapour and hydrogen sulphite. Natural gas is produced onshore or offshore and it can be found either by itself or in association with crude oil. After its extraction natural gas is treated in facilities near the well in order to prepare it for the market. During this process the various ingredients of the raw natural gas such as the water vapour are removed and the treated natural gas mainly, methane, is directed towards the final consumers. Natural gas can be transported in gaseous form via a pipeline system or in liquid form via specially designed carriers and then fed into the regional transmission system (IGU, 2019d).

Natural gas is transformed into Liquified Natural Gas (LNG) by cooling it down to its condensation temperature of -162ºC (-260ºF) at atmospheric pressure.  This process is called liquefaction (GIIGNL, 2019b). The volume of the natural gas when liquefied is decreased by 600 times, a property that makes the liquefaction process ideal for the transportation of volumes of natural gas, with huge energy content over the world. Throughout the whole transportation process, the temperature of the LNG is maintained below -162ºC in order to keep the cargo in liquid state. When the cargo reaches the discharge terminal it is stored in tanks and then it is gradually regasified in specially designed industrial complexes by heating it up to a temperature higher than the condensation point, in order to be forwarded to the distribution network in a gaseous state (IGU, 2019d). The value chain is depicted in the picture below.

[1] Kostas Andriosopoulos is a Professor in Finance and Energy Economics at ESCP Business School and a Board Member of the Global Gas Center / World Energy Council

*Figure 1. The Gas Industry Value Chain*




*Source: IGU (2019d)*

Over the past few years there an alternative for the transportation of natural gas mainly for small onshore distances was introduced. That is the transportation of natural gas in its compressed form, which is called compressed natural gas (CNG). In contrast to LNG, compressed natural gas is transformed into a supercritical liquid not by cooling but by compression. The volume of the natural gas is decreased by 200 times (DEPA, 2019). Natural gas is compressed at a "mother station" at a pressure range of 250 bar. Then the CNG is loaded in specially designed containers and carried to the final destination by trucks or rail.

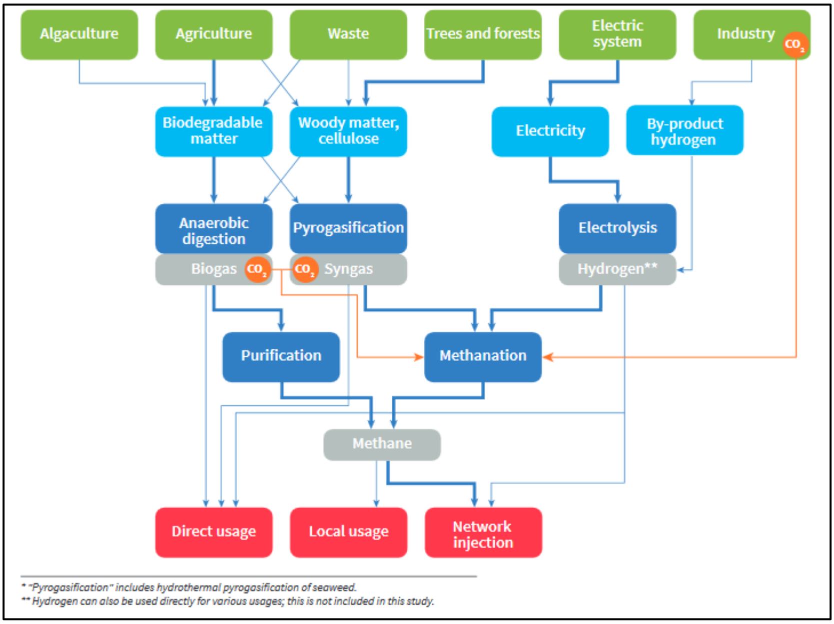
There a decompressing station is installed in order to reduce the pressure of CNG and return it to its initial gaseous stage (DEPA, 2019). The advantage of the use of CNG is that it makes feasible the transportation of natural gas to remote areas where the construction of a pipeline is financially rejected. That is the reason that it is often called as a virtual pipeline (Baker Hughes, a GE Company, 2019). Another innovative project is being developed by some transmission system operators that operate both pipelines and multiple LNG terminals. In the proposed scheme, it is made feasible for an offtaker to unload a cargo of LNG in one terminal and take the same amount of LNG regasified from another terminal somewhere else (CEER, 2019). That agreement allows the "flow" of gas in another type of "virtual pipeline".

The big challenge however that the energy industry is facing is the decarbonisation of the energy mix and the further use of renewable energy sources (ADEME, 2018). The gas industry has taken seriously the fight to counteract climate change and is set to promote the use of renewable gases (Navigant, 2019). In general, by renewable gases, we refer to a series of different gases that can be used to create energy. In the following graph we can see the ways that these gases are produced.

The main processes include anaerobic digestion, pyrogasification and power-to-gas methods. Anaerobic digestion is the process through which organic matter is decomposed by the use of bacteria for the production of biogas, a gas mix mainly of methane and carbon dioxide. After treatment to remove carbon dioxide, leaving more than 97% of methane in the mixture, it is called biomethane and can be injected into the natural gas transportation system (ADEME, 2018). Pyrogasification is a thermo-chemical method, in the broad sense, enabling production of a synthetic gas, called syngas, also from organic matter. The difference from anaerobic digestion is that pyrogasification is mainly used for dry woody material.

Finally, power to gas projects, are intended to use the excess electricity that is produced by renewable sources and is not needed in the system, in order to transform it into gas and store it for later use. This product is called green hydrogen (Gas for Climate, 2019). If a second step, that of the addition of carbon dioxide is added to the process, then the final product will be methane and the process is called power-to-methane (EBA, 2019). Another gas that is considered is blue hydrogen which is low carbon hydrogen gas produced from the pre-combustion carbon capture of hydrocarbons (Gas for Climate, 2019). There are several studies that show that a mix of natural gas and hydrogen in the same pipeline system is feasible (EBA, 2019, Navigant, 2019).

*Figure 2. Various Processes for the Production of Renewable Gases*




*Source: ADEME (2018)*

Europe is trying to take the lead in the field of renewable gases, and that is shown by the initiative of several European distribution system operators to try to decarbonise their networks. Their aim is to help in reaching by 2050 a net carbon EU energy system and to have at least 10% of renewable gas in their grids by 2030 (Gas for Climate, 2019). They are pushing the European Union to make the 10% target for 2030 binding for its member states in their new national programs for the next decade. The only binding target set by the Renewable Energy Directive (RED II) (European Parliament, 2018*)* was for 3.5% of advanced biofuels and biogas in the transportation sector.

## 1.2 LNG markets and global trends

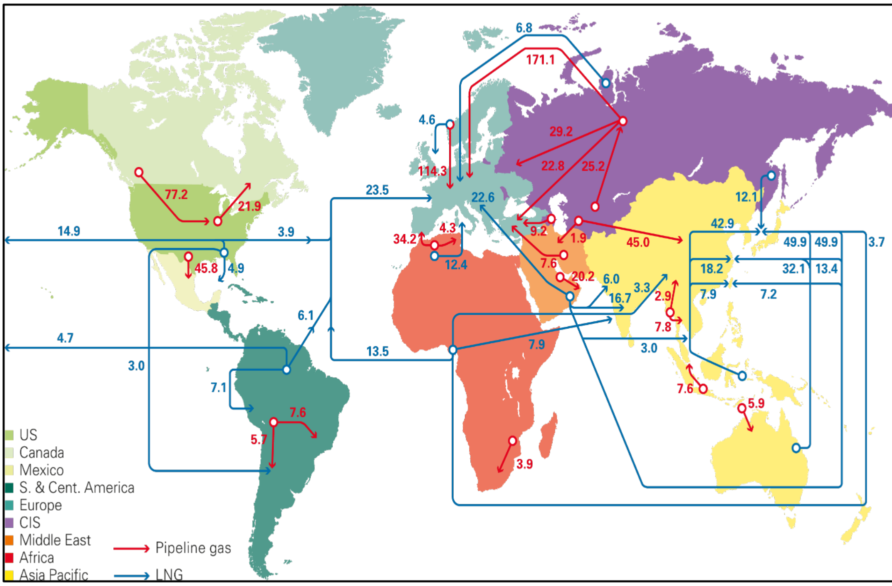
In a global perspective an important turn was taken in the last years of the first decade of the 2000s with the shale gas revolution (IEA, 2019b). The combination of two pre-existing technologies, directional drilling and hydraulic fracking, changed the scene in the hydrocarbons industry completely, bringing the shale oil and shale gas revolution. With directional drilling it was possible to drill wells not only on a vertical axis but also horizontally or under any incline. Hydraulic fracking is the method to widen pre-existing cracks on the surface of impermeable sedimentary rocks with the use of pressurised water, sand and chemicals. These rocks were full of hydrocarbons which are now at hand for extraction. Until the shale gas revolution, the US was preparing to be a net importer of hydrocarbons and regasification terminals were built in order to import LNG.

The exploitation of the shale gas reserves made redundant the need for gas importing terminals and allowed them to be reconfigured into exporting terminals, with liquefaction plants, in order to supply the global market with US LNG (IEA, 2019b). The economic crisis of 2008 halted economic growth with a consequent stop in the growth of the gas demand. As a result, prices decreased. In March 2011 the earthquake with the subsequent tsunami that hit the Japanese coast, and the accident at the Fukushima nuclear power generation station resulted in the temporary closure of all the Japanese nuclear power stations until September 2011. That led to a demand shock for natural gas for power generation in Japan. Of course, Japan could only import LNG, leading to a sudden increase in LNG prices. The importation of Qatari LNG was the immediate response to the demand. Also, many re-exports from Europe to the Asian markets were observed (IEA, 2019b), because of destination clauses that were in the contracts between the producers and the off-takers.

A destination clause in a contract means that the cargo is loaded at a liquefaction plant and must be unloaded to a specific port. It cannot change its route and discharge to another terminal. It was common at the time to have a cargo of LNG loaded in Qatar, unload it to a Spanish terminal, due to the destination clause, and then load the same cargo again in order to sell it on the spot Asian market at a higher price. The high expectations for demand from China and the other countries in the region led to a second wave of investments both in liquefaction plants and LNG carriers (IEA, 2019b). Asian LNG import prices dropped by more than one-third between 2015 and 2017, compared to price levels between 2012 and 2014. Today we are experiencing again a well-served market, partially due to lower demand from the Japanese market and the oversupply of natural gas in the United States (IEA, 2019b).

By the end of 2018 there were 20 LNG exporting countries and 42 LNG importing countries (GIIGNL, 2019a). The pricing and the duration of LNG and natural gas contracts has in general changed throughout the years. For the price we have shifted from contracts based on oil indexation, meaning the natural gas price was linked to that of crude oil, to gas-on-gas pricing, by developing hub price references like the Henry Hub price for the US market or the NBP or the TTF price for the European markets (GIIGNL, 2019a). To be more precise, gas-on-gas indexation rose from 23% in 2005 to 61% in 2018, whereas oil price indexation declined from 57% to 31%, in pipeline imports worldwide. As far as the LNG trade is concerned, in 2018 34% of trade was defined by gas-on-gas competition and 66% was oil indexed (IGU, 2019a). LNG contracts that that have less than 5 years of duration or are settled in the spot market, hit a record 31% of the total LNG traded in 2018, compared with 29% in 2017 and a 10% increase from that of 2008 (IGU, 2019b).

***Figure 3. Major Gas Trade Movements in bcm***




***Source: BP (2019)***

The majority of global exports in 2018 happened via pipelines was 65% of the total while the remaining 35% was transported as LNG (BP, 2019b). As far as the interregional trade is concerned the pipelined gas represents 54% of the trade with LNG being 46% in 2018 (BP, 2019b). It is projected however that LNG trade will grow to 60% of the total interregional gas trade by 2024 (IEA, 2019c). It becomes clear that there is a transition of the natural gas markets from local to regional and global.

On the LNG supply side, the United States, and on the demand side, China, are influencing the LNG market mostly because of their growth potential. China has become the second biggest LNG importer after Japan, and the United States has made it to the top 5 exporting LNG countries (IEA, 2019c). In 2018 Japan imported 109 bcm of regasified LNG, China 73 bcm and Korea 59 bcm (GIIGNL, 2019a). On the supply side Qatar was the largest exporter of LNG with 102 bcm, followed by Australia with 90 bcm and Malaysia with 32 bcm. The United States exported 28bcm in 2018 and has a tremendous list of liquefactions projects underway. In the first nine months of 2019 alone, we had the startup of commercial operation or substantial completion of facilities that add more than 28 bcm of liquefaction capacity (GIIGNL, 2019a). There are projections (IEA, 2019d, Tsafos, 2019), that by the next decade the US liquefaction capacity will be challenging that of Qatar and Australia at a range of 100-150 bcm/year (IEA, 2019b).

In 2018, the global production of natural gas was 3.937 bcm, which is a 4.0% increase compared to 2017. The largest producer was the United States with a production of 859 bcm, mainly due to the increased production of shale gas. It is followed by Russia (725 bcm) and Iran (220 bcm). Australia produced 132 bcm and in Europe, Norway was the biggest producer with 127 bcm. As far as Africa is concerned Algeria produced 96 bcm (IEA, 2019c).

Another important factor that will shape the LNG market is the use of LNG as a bunkering fuel instead of heavy fuel oil. Following the instructions of the International Maritime Organisation from January 1st, 2020 all ships must abandon the use of fuels that have more than 0.5% of Sulphur content (ABS, 2017). The ship owners are given three options, either to change to a fuel that meets the new specification, or to install specially designed systems, called scrubbers, that filter the exhaust fumes and absorb the sulphur dioxide in them or to shift to LNG which has zero sulphur content. It has been shown by various reports that the installation of the scrubbers is economic only for relatively new ships and not old ships (IEA, 2019c).

The use of LNG as the primary fuel for the shipping industry is evident in the increase in the number of newly built vessels that will use it in the future (GIIGNL, 2019a). Until early 2019 the total LNG-fueled fleet numbered 718 vessels, of which 530 were LNG carriers with the capability of burning both LNG and fuel oil. There were also 33 FSRUs and 155 vessels burning LNG (IEA 2019b, GIIGNL, 2019a).

The projection of the IEA is that by 2024 the annual LNG consumption will be close to 7.5 bcm from 0.7bcm in 2018. A major drawback for the rapid expansion of the LNG as a marine fuel is the lack of the infrastructure that will support the bunkering process, which requires the development of common standards in the infrastructure worldwide (IEA, 2019b, Le Fevre, 2018). In a particular case made by Sharples, (2019) for Northern Europe, the author concluded that the IMO change in regulation will not produce a significant push for the use of LNG in that region for a number of reasons.

## 1.3 European gas and LNG markets

***<u>The European Union Objectives</u>***

The European Union, through the mission statement of the General Directorate of Energy, has set the goals of its energy policy. The mission of DG Energy is:

"*DG ENER is responsible for developing and implementing the Energy Union, one of the Juncker Commission's priorities. DG ENER proposes, implements and reviews legislation under the Energy Union framework strategy, focusing on five key dimensions:*

- *Energy security, built on solidarity and trust between EU countries*
- *A fully functional internal energy market*
- *Energy efficiency as a contribution to moderation of energy demand*
- *Decarbonisation of the economy*
- *Research, innovation and competitiveness.*

*The Directorate-General for Energy (DG ENER) works towards secure, sustainable, competitive and affordable energy for all EU citizens*"

The realisation of this policy is evident when it comes to the gas markets, as an energy trilemma: the decarbonisation of the energy mix, the affordability of energy and the availability of energy at any time, in the sense of security of supply. The European Union is calling its member states to decarbonise their energy mix by shutting down coal fired power generation plants and substituting them with power generation from renewable sources. In order to achieve a smooth transition to a fossil fuel-free energy mix natural gas has an important role to play. Power generation from natural gas either in single cycle power plants or combined cycle power plants produces less emissions, less carbon dioxide, less nitrogen oxides, less sulphur oxides and less particles compared to power generation burning coal or even oil (IGU, 2019d).

One more advantage of power generation from natural gas is that it provides the ideal match to the stochastic and variable power generation behavior of the RES. The reasons for that are firstly that ramping up from a cold state is faster compared to that of coal and oil plants and secondly that their starting time is also smaller making them perfect for serving as reserve capacity for the balancing of the grid (IGU, 2019d). Moreover, if the evolution of industrial-sized battery storage becomes a reality, power generation from natural gas will become increasingly redundant, but until that time comes natural gas has a major role to play in the reduction of greenhouse emissions (European Commission, 2019d).

One more goal of the European Commission is to make energy affordable for all its citizens by introducing competition in the energy market. The unbundling of the electricity and gas markets was a step towards that goal. The development of energy exchanges and the proposed interconnections between member states will allow trade to flourish and energy to flow between countries leading to a convergence in a common European price for energy commodities.

Finally, security of supply is strengthened not only by the diversification of the energy mix as explained above but also by the diversification of suppliers and supply routes.

***The European Projects of Common Interest (PCI) Scheme***

In order to facilitate the realisation of the investments needed the European Union has decided to grant funds through the Projects of Common Interest (PCI) scheme. Projects of common interest (PCIs) are key cross-border infrastructure projects that link the energy systems of EU countries.

A project can receive funds only if it fulfils five criteria. It must:

1. have a significant impact on at least two EU countries
2. enhance market integration and contribute to the integration of EU countries' networks
3. increase competition on energy markets by offering alternatives to consumers
4. enhance security of supply
5. contribute to the EU's energy and climate goals.

There have been already three PCI lists and the consultation for the fourth is underway. The current third PCI list contains 173 projects: 106 electricity transmission and storage, 4 smart grid deployment, 53 gas, 6 oil, 4 cross-border carbon dioxide networks.

The PCI-related gas projects have been divided into four distinct clusters as follows:

1. The Priority Corridor North-South Gas Interconnections in Western Europe (‘NSI West Gas’)
2. The Priority Corridor North-South Gas Interconnections in Central Eastern and South Eastern Europe (‘NSI East Gas’)
3. The Priority Southern Gas Corridor (‘SGC’) and
4. The Priority Corridor Baltic Energy Market Interconnection Plan in Gas (‘BEMIP Gas’)

The region of Southeast Europe is mainly covered in the NSI East Gas and SGC clusters. Pipeline projects that are included in these projects are the interconnection Greece-Bulgaria, the interconnection Bulgaria-Serbia, the Bulgaria-Romania-Hungary-Austria bidirectional transmission corridor, the Interconnection Croatia-Slovenia, the Trans-Anatolia Pipeline (TANAP), the

Trans-Adriatic Pipeline (TAP), the offshore gas pipeline connecting Greece and Italy, and the East Med Pipeline.

Also, two LNG terminals in the region have been included in the PCI list, the Krk LNG import terminal in Croatia and the Alexandroupolis LNG import terminal in Greece. Finally, four gas storage facilities have received funds (two in Romania, one in Bulgaria and one in Greece).

***Major European Pipelines and Gas Routes***

The major trade counterparts, as far as pipeline gas is concerned, are Russia from the East, Norway from the North and Algeria and Libya from the South of the European Union (European Commission, 2019c). More specifically, Russia exported around 110 bcm of natural gas to the EU in 2018 via a complex system of pipelines (Gazprom Export, 2019). The major pipelines are:

- Nord Stream 1 which consists of two offshore pipelines across the Baltic Sea, from Russia to Germany, that can transmit up to around 55 bcm/year.
- Yamal-Europe I, which transmits gas from Russia to Poland and Germany via Belarus having a capacity of up to 33 bcm/year.
- The pipeline network within Ukrainian territory; the Brotherhood (Urengoy-Pomary-Uzhgorod pipeline) and Soyuz pipeline; the Progress pipeline (the largest gas pipeline route from Russia to Slovakia, which delivers gas to the Central and Western European countries and has a capacity of about 100 bcm/year); the Trans-Balkan pipeline that delivers gas to the Southern Europe countries and finally Turkey with a transportation capacity of 20 bcm/year.

As far as non-EU countries are concerned there are some other pipelines that service the market such as Blue Stream that delivers Russian gas to Turkey through the Black Sea with a capacity of 16 bcm and the North Caucasus pipeline that carries up to 10 bcm of Russian gas to Georgia and Armenia (Gazprom Export, 2018).

The second largest exporter of gas to the EU is Norway. Norway’s offshore pipeline system is connected with the networks of Germany, UK, France, Netherlands and Belgium. The overall capacity of the system is around 120 bcm/year (Norwegian Petroleum, 2019). There is uncertainty about the future gas production of Norway due to the depletion of the existing gas fields and the need for further exploration and production activities that has recently arisen. The fact that the Norwegian sovereign wealth fund is said to be reducing holdings in oil stocks, (Gilblom, 2019) might make the financing of Oil & Gas projects more difficult.

Algeria is the third largest exporter of gas both via pipelines and LNG. It provides the EU with about 23 bcm/year, around 5% of EU supplies (European Commission, 2019f). The major pipelines are:

- Pipeline Enrico Mattei (GEM): which can carry about 38 bcma and transports gas from Algeria to Italy via Tunisia and the Mediterranean Sea.
- Maghreb–Europe Gas Pipeline (MEG): which has a capacity of around 11 bcma and its routed from Algeria to Spain via Morocco.
- MEDGAZ pipeline: which has a capacity of 8 bcma and delivers the gas directly from Algeria to Spain via the Mediterranean Sea (EIA, 2019a).

Other minor exporters are Libya which delivers gas to Italy via the Green Stream pipeline with a capacity of 12 bcma and Azerbaijan, which is about to deliver gas to the Southern European countries using the Trans-Anatolian Pipeline (TANAP) and Trans-Andriatic Pipeline (TAP) through Turkey, Greece and Albania as transit countries. The pipeline has a capacity of 16 bcm (6 bcm are planned to feed the Turkish market while the remaining 10bcm are to be transported to the European market). (TANAP, 2019)

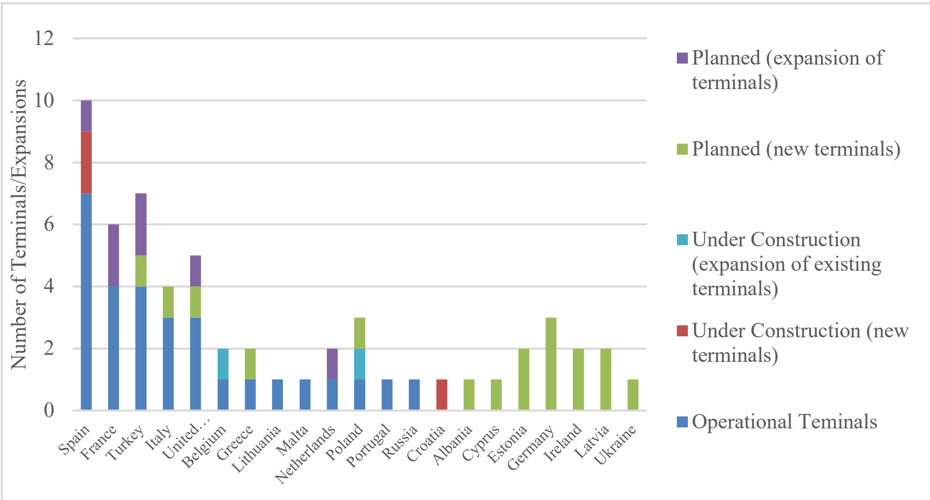
***LNG Import Terminals***

In Europe, there is a number of LNG import terminals which vary in size and construction design. As of May 2019, there are 7 small-scale import facilities and 29 large-scale import terminals in Europe and Turkey. Of the 29 large scale facilities, 22 are onshore and 7 are offshore.

In order to classify a facility as a large-scale facility, it must have a regasification capacity of more than 0.5 bcma (GIE, 2019b). The existing terminals as well as the terminals that are under construction and the proposed new facilities and the number of the planned expansions in operating terminals are shown in Figure 4.

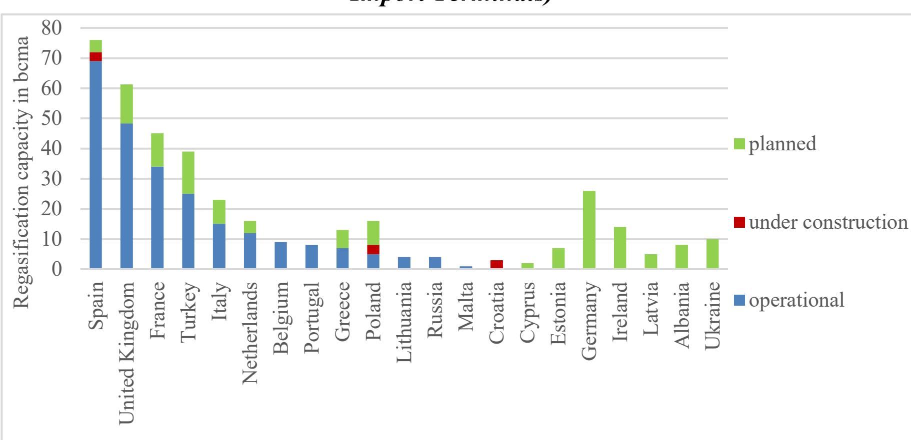
Spain is the country with the most terminals in its territory, with 7 operating terminals, 2 new terminals under construction and one planned expansion of an operating terminal. In total, there are 13 countries that have large-scale import infrastructure in operation. Croatia is building its first LNG importing terminal and there are seven countries that are planning their first regasification terminals. The total regasification capacity in Europe is 241 bcm of LNG per year. The capacity per country is illustrated in Figure 5.

***Figure 4. Number of Existing Large-Scale Terminals and Planned Projects per Country***




***Source: GIE (2019b)***

***Figure 5. Regasification Capacity Per Country in bcma (Large Scale Import Terminals)***



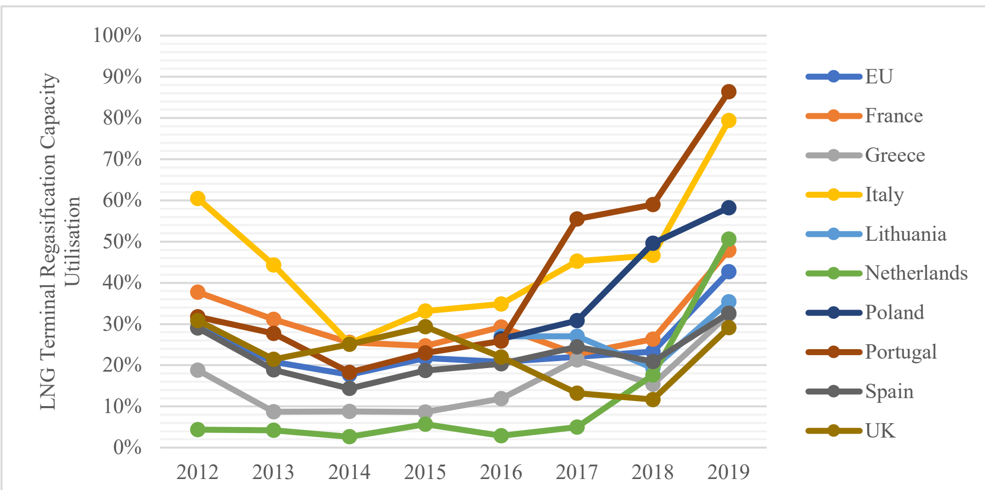

***Source: GIE (2019b)***

Spain is also the country with the highest regasification capacity with 69 bcma, followed by the United Kingdom with 48 bcma, France with 34 bcma, Turkey with 25 bcma and Italy with 15 bcma. These five countries represent almost 80% of the regasification capacity in the region.

The growth potential of the sector can be verified by the 3 facilities that are under construction with a total of 9 bcma regasification capacity and even more by the 17 import terminals that are planned (regasification capacity of 140 bcma) and are expected to increase the capacity by over 55%. By the time that all the projects are implemented, the total regasification capacity in Europe will be around 390 bcma (GIE, 2019b).

Nevertheless, the regasification capacity utilization rate of these terminals is a parameter that must be taken into consideration. The following graph depicts the terminal utilisation rate of France, Greece, Italy, Lithuania, Netherlands, Poland, Portugal, Spain, United Kingdom and an aggregate of these countries.

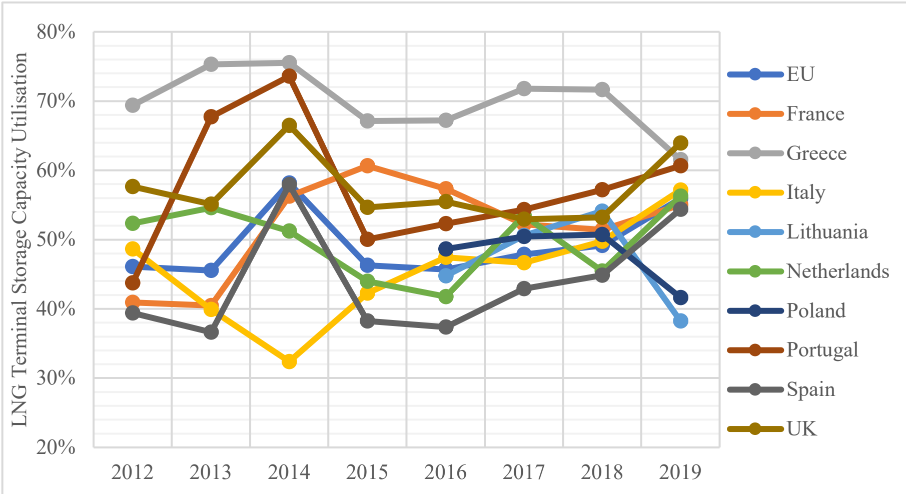
***Figure 6. LNG Terminal Regasification Capacity Utilisation Rate per Country***




***Sources: ALSI (2019), Author's calculations***

From the graph we can see the trend of underutilisation of the LNG terminals for the years from 2013 until 2016. From 2016 and onwards the utilisation rate of the terminals has been increasing every year, with 2019 being the year that has the highest rate, although the data are available until the end of September 2019, which covers the summer period when normally the utilisation rate is lower. With that note in mind we expect the rates to be even higher for 2019. In total for the years 2017, 2018 and 2019 we had in aggregate for the area under examination, utilisation rates of 22%, 23% and 43% respectively. Furthermore, in the Netherlands, a country that up to 2017 had a rate up to 10%, in 2019 we see an impressive rate of more than 50%. Portugal and Italy on the other hand have always been countries that had high utilisation rates, reaching in 2019 86% and 79% respectively. The utilisation rate of LNG storage capacity on the other has been relatively stable throughout the years.

*Figure 7. LNG Terminal Storage Capacity Utilisation per Country (%)*




***Sources: ALSI (2019), Author's calculations***

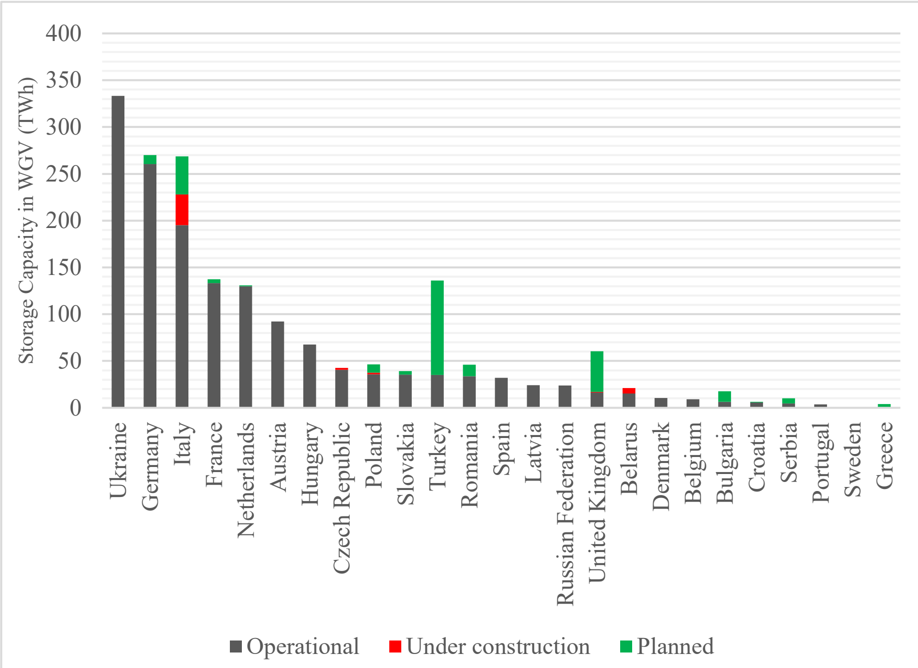
The average utilisation rate in the aggregated area was around 50% in 2019, until September, with Poland and Lithuania having the lowest rates, at around 40%, and the United Kingdom having the highest with about 63%.

In order to further increase the utilisation of their facilities the operators have developed further ancillary services for their users, apart from LNG storage and regasification (Agosta, Øydvin and Beek, 2018). These include for instance, LNG bunkering services for the maritime industry, the possibility of truck loading or rail loading of LNG, to transport it in specially designed containers to remote areas, reloading LNG onto small or large ships and transhipment from ship to ship (GIE, 2019c). The terminals in the north-west and west of Europe where the first to offer these kinds of services (GIE, 2019d) and the others followed their example, occasionally with more innovative spirit.

***<u>Storage Facilities</u>***

Another important parameter for the European gas market is the gas storage capability. Gas storage facilities can have various forms, either naturally or artificially formed. These forms vary from underground gas storage (UGS) facilities that are depleted hydrocarbon fields, geological formations such as rock caverns, salt caverns or aquifers to manufactured facilities. Figure 8 presents the existing, under construction and planned storage facilities in the European Union, Ukraine, Belarus, the European part of Russia, Serbia and Turkey as of July 2018 by Working Gas Volume (WGV).

*Figure 8. Storage Capacity per Country by WGV (in TWh)*




*Sources: GIE (2019e) and Author's Calculations*

The total storage capacity of the European Union is about 1.131 TWh, with Germany, Italy and France being the countries that have the largest storage capacities, with 260 TWh, 195 TWh and 133 TWh respectively. Italy is constructing and planning to develop several projects (additional capacity of 62 TWh) and will challenge Germany for the first position in EU storage capacity. France and the Netherlands have around 130 TWh of storage capacity, and Turkey is aspiring to reach that level with a group of planned projects of 100 TWh to be added to its 30 TWh existing storage. The country that is currently in possession of the largest gas storage capacity is Ukraine, with more than 330 TWh of storage, which is equal to almost one third of the total EU storage. Overall, the planned projects in the EU area amount to 140 TWh, representing, if completed, an increase of 10% in the total existing EU capacity (GIE, 2019e).

Chapter 2

# The Role of Natural Gas in the EU Decarbonisation Path

# 2. The Role of Natural Gas in the EU Decarbonisation Path

By Dr. Simone Tagliapietra[2]

## 2.1 The EU's quest for decarbonisation: from Kyoto to the 20-20-20 targets

Over the last two decades, decarbonising the European economy has become a key policy priority for the European Union (EU). The first steps in this direction were taken by the EU in the framework of the international negotiations on climate change. In 2002, the EU adopted legislation approving the Kyoto Protocol, stating that it would jointly fulfil with its Member States the commitment to reduce the collective greenhouse gas (GHG) emissions in the 2008-2012 period to 8% below 1990 levels (European Commission, 2002).

In this new international context, EU Member States agreed for the first time on the need for comprehensive common action towards the increasingly challenging energy issues at the Hampton Court informal EU summit held in October 2005. Following the political momentum which emerged at the summit, the European Commission published in early 2006 a Green Paper on developing a common and coherent European energy policy entitled “A European Strategy for Sustainable, Competitive and Secure Energy” (European Commission, 2006). As the title suggests, the paper delineated a European energy policy structured on three key pillars, which continue to remain fundamental today.

The Green Paper received the praise of the European Council of March 2006, which called for «an Energy Policy for Europe, aiming at effective Community policy, coherence between Member States and consistency between actions in different policy areas and fulfilling in a balanced way the three objectives of security of supply, competitiveness and environmental sustainability» (European Commission, 2006). The European Council therefore invited the European Commission to prepare further actions.

The Commission reacted to this endorsement by issuing in January 2007 the so-called “Energy and Climate Package”, a set of measures centred on the Communication “An Energy Policy for Europe” (European Commission, 2007) aimed at establishing a new European energy policy in line with the one proposed in the Green Paper (and thus focused on combat climate change, increasing EU energy competitiveness and boosting the EU's energy security

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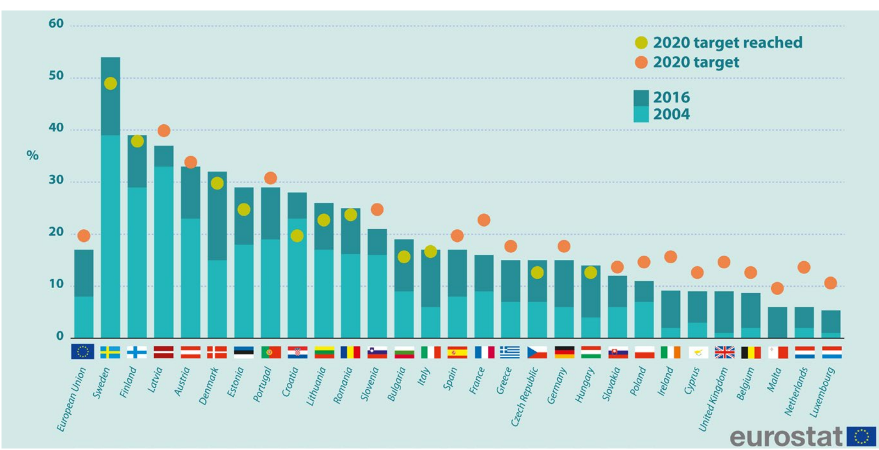
of supply). The European Council of March 2007 endorsed the package (European Commission, 2007), which was then finally adopted by the European Parliament in December 2008 after months of tough negotiations between Member States.

In addition to the definition of the triple paradigm - sustainability-competitiveness-security - characterizing the European energy policy, an important advance included in the “Energy and Climate Package” was represented by the EU’s commitment to reach specific targets related to GHG emissions reduction, renewable energies and energy efficiency: the well-known 20-20-20 targets. These targets encompassed a 20% reduction of GHG emissions compared to 1990, a 20% decrease of final energy demand compared to a baseline scenario and the attainment of a level of 20% of renewable energy in total energy consumption, by 2020.

These targets had a substantial impact on the EU energy system, particularly as far as the penetration of renewable energy in the system is concerned. As illustrated by Figure 9, the share of renewable energies in EU gross final energy consumption stood at 17% in the EU in 2016, compared with 8.5% in 2004. Overall, the EU is on course to meet its 2020 targets. Some Member States have already reached and surpassed their individual, legally binding, targets, while other Member States still need to make additional efforts to meet their obligations.

***Figure 9. Share of Energy from Renewable Sources in the EU Member States (% of Gross Final Consumption)***




***Source: Eurostat (2018)***

### ***<u>After the 20-20-20 targets: the 2030 Climate and Energy Framework</u>***

In the run-up to the Paris Agreement, the European Commission took a step further on its decarbonisation policy path in 2014, with the adoption of the Communication "A Policy Framework for Climate and Energy in the Period from 2020 to 2030" (European Commission, 2014a). This new document focuses on the reduction of GHG emissions (by 40% below the 1990 levels by 2030), on the increase of renewable energy use (at least 27% of the EU's energy consumption by 2030), on the increase of energy efficiency (27% of energy savings target for 2030) and on the reform of the EU Emissions Trading System (ETS). This set of provisions was endorsed by the European Council of October 2014 (European Council, 2014).

Following this approval, between 2015 and 2016 the European Commission made its legislative proposals to implement the 2030 Framework. After negotiations between the European Commission, the European Parliament and the Council, in November 2018 the European Parliament approved a binding renewable energy target of at least 32% and an energy efficiency target of at least 32.5. When these policies are fully implemented, they will lead to steeper emission reductions for the whole EU than anticipated– some 45% by 2030 compared to 1990, instead of 40% (European Commission, 2018a).

It is important to underline that, unlike in the previous 2020 framework, the new EU targets will not be translated into national targets via EU legislation. Officially, this is due to the willingness to leave greater flexibility for Member States to meet their GHG reduction targets in the most cost-effective manner in accordance with their specific circumstances, energy mixes and capacities to produce renewable energy. In reality, this seems to be mainly due to the lack of a common vision among Member States on the future trajectory of the decarbonisation path, with certain countries (from the United Kingdom to Poland) being reluctant to afford its high costs and being more sensitive to the competitiveness and security pillars of EU energy policy.

To overcome this political difficulty while ensuring the 2030 energy and climate targets are achieved, the European Commission opted to strengthen the governance of the EU energy and climate policy, by introducing the 'Integrated National Energy and Climate Plans'. In short, EU countries are now required to develop these Plans, which cover the five dimensions of the Energy Union for the period 2021 to 2030 (and every subsequent ten-year period) based on a common template. Then, they will have to report on the progress they make in implementing the Plans, mostly on a biennial basis.

## 2.2 Pursuing the 2030 targets: What role for natural gas?

Increasing the use of renewable energy to 32% of overall EU energy consumption by 2030 will imply a substantial expansion of the current contribution of renewable energy to electricity generation. Today, the EU renewable electricity generation mix remains largely based on hydro. But considering that the potential for hydro in the EU is already well exploited, the new 2030 target will thus require an extensive development of variable renewable energy sources such as wind energy and solar energy - namely photovoltaic (PV).

Up to date, wind and solar PV have been developed with a 'fit and forget' logic, being not integrated into the electricity market and having priority dispatch and access to networks. However, a massive integration of such variable renewable energy sources into the system will require profound changes in terms of power system operation, market design, infrastructure development and transformation of conventional generation mix.

Being dependent on uncertain weather conditions, wind and PV are variable by definition and their output is both intermittent and non-dispatchable. For this reason, more flexibility will be required in the system, in order to reduce this intermittency and ensure the overall stability of the system. Flexible resources include dispatchable back-up power plants, demand-side management and response, energy storage facilities and interconnections with adjacent markets. The main tool for reducing the intermittency of wind and PV electricity generation is to aggregate their outputs over a wider geographical area. In fact, intermittency at site level is progressively smoothed at regional, national and continental levels as a result of the diversity of outputs.

In other words, the integration of EU electricity systems can mitigate flexibility needs arising from wind and PV, by taking advantage of different weather patterns across Europe that decorrelate single electricity generation peaks, yielding geographical smoothing effects that ultimately transform intermittency at local level into variability at EU level. In addition to this, a strong integration of EU electricity systems can allow the cross-border exchanges necessary to minimise surplus renewable electricity generation. When no trading options exist, hours with high domestic wind and PV generation require that generation from renewables be stored or curtailed in part. With market integration, decorrelated production peaks across countries enable exports to regions where the load is not covered. By contrast, a hypothetical national autarchy case has storage or curtailment requirements that are ten times as high.

The process of integration of EU electricity systems will require the development of an appropriate network infrastructure, and particularly of interconnections not only able to transport wind and PV electricity production to consuming centres but also to share thermal generation capacity between EU countries. The development of an appropriate infrastructure is thus not only crucial to reduce variability of wind and PV at system level but also to reduce the overall need for back-up electricity generation. This represents a vital element, particularly if considering that by displacing baseload generation (i.e. from conventional sources) wind and PV increase the need for back-up capacity.

With an increased role of wind and PV in EU electricity systems, conventional plants are thus progressively switching from their traditional roles to a new back-up role, essential to guarantee the stability of the overall system vis-à-vis the variability of wind and PV. In addition to interconnections, flexibility in the system could theoretically be enhanced with demand side management and demand response mechanisms as well as energy storage. However, these solutions face major challenges. Demand mechanisms are partially challenged by socio-economic issues such as consumer behavioral changes, albeit can well be implemented in the industry and services sectors first. Energy storage is challenged by a persistent technological gap; in fact, to date the only operative option is represented by pumped hydropower storage, as other technologies such as battery systems, compressed air energy storage, flywheels and hydrogen storage continue to be highly expensive. In sum, in the medium-term these solutions are unlikely to provide a substantial contribution to back-up in the system.

In this framework, exploiting the complementary roles of renewable and conventional electricity generation sources will be even more important in future EU electricity systems. In particular, conventional sources will continue to play a key role in guaranteeing system stability and security of supply by being able to provide larger and more rapid increases and decreases in output in order to accommodate increasing amounts of variable renewables-based generation. With regard to this specific aspect, the International Energy Agency (IEA) points out that the integration of high levels of wind and PV into electricity systems may require market framework reforms to guarantee a sufficient level of investment in the conventional power plants needed to keep the system in balance, together with other measures to shift demand when the sun is not shining or the wind is not blowing. Failing to address these needs in advance will negatively impact the reliability of the electricity system.

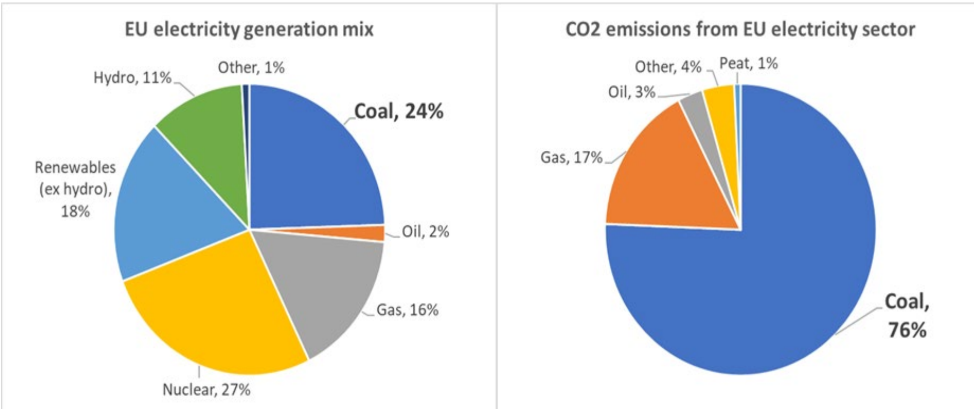
This seems to be particularly urgent in the case of the EU, where variable renewables are set to become the cornerstone of the electricity system, increasing the variability that the rest of the system has to manage. Of course, a new EU electricity market design should also be able to provide adequate economic incentive for investments in the previously mentioned flexibility options (i.e. network infrastructure expansion, development of smart grids, adoption of demand side measures and development of energy storage technologies), crucial to ensure the sustainability of the EU decarbonisation path also beyond the 2030 horizon. To make a long story short, in order to achieve its 2030 renewable energy targets the EU must rethink its entire electricity system. The role of natural gas in the future system should also be better investigated. This is particularly true considering the persistent role of coal in the EU electricity system.

## 2.3 The EU decarbonisation path and the (unwelcome) renaissance of coal

Even if, over the last decade, the EU electricity system has modernized and become greener, it has also maintained its oldest and most polluting component: coal. The share of this fossil fuel in the EU electricity generation mix stands at 25%, having declined by only 5% between 2000 and 2015. Coal indeed remains predominant in electricity generation in several EU countries, from Poland to Germany. Currently, coal generates 75% of the CO2 emissions from the EU's electricity and heat sector, which in turn represents a quarter of the EU's total CO2 emissions. Phasing-out coal is thus key to the decarbonisation of the EU energy system.

The persistent role of coal in the EU electricity system represents a problem for the climate, for the environment and for human health. From a climate perspective, coal is the worst way to generate electricity. Carbon dioxide (CO2) emissions from coal are higher than those of oil and gas. To generate the same amount of electricity, a coal-fired power plant emits 40% more CO2 than a gas-fired power plant and 20% more than an oil-fired power plant (UNFCCC, 2017). To produce enough electricity for an average European household for one year, five tonnes of CO2 would be emitted if the electricity was generated from coal, three tonnes if generated from gas and zero tonnes if generated from wind and solar.

***Figure 10. Electricity Generation Mix in the EU and CO2 emissions from EU electricity (2016)***




***Source: Author's elaboration on Eurostat and European Environment Agency***

There are very limited ways to improve the efficiency of coal and to make it cleaner. New more efficient, or 'ultra-supercritical', coal power stations still produce substantially more CO2 than gas power stations. Meanwhile, carbon capture and storage technology remains unproven as a fully integrated process. Effective capture technology has not been developed and safe long-term storage at a necessary scale has not been demonstrated. Therefore, it is hard to see how carbon capture and storage for coal would ever be able to compete on price with renewables, the costs of which are rapidly falling.

Coal is broadly bad for the environment, beyond being bad for the climate. Coal-fired power plants across Europe are responsible for the largest volumes of Sulphur dioxide, nitrogen oxides and particulate matter released into the air (European Environment Agency, 2017). These pollutants have a range of health effects, causing, in particular, breathing problems such as asthma and bronchitis, which can even prove fatal. Up to 400,000 premature deaths annually in the EU are attributed to air pollution (European Environment Agency, 2017). Heavy metals such as mercury are also released into the air by coal-fired power plants. These can impact the immune system, with children most at risk. According to the World Health Organisation (2017), 33 out of the 50 most-polluted cities and towns in Europe are located in Poland, notably in the coal mining region of Upper Silesia. In this context, it is widely recognized that natural gas could, over the next decade, provide a significant contribution to replacing coal in the EU electricity generation mix alongside the growing role of renewable energy sources.

## 2.4 Exploring the future role of natural gas in the EU decarbonisation path

Albeit technically feasible, a further large-scale development of wind and PV in the EU electricity system might potentially encounter economic barriers due to increasing system integration costs. This issue is particularly relevant if considering that the EU itself acknowledges that in the future, the benefits of renewable energy must be exploited in a way which is to the greatest extent possible market driven and thus not based on support schemes that ultimately hinder market integration and reduce cost-efficiency.

In this context, assessing the future role of conventional electricity generation is of vital importance for the stability and security of the EU electricity system. As an overall trend, considering the previously illustrated characteristics of an electricity system centred on variable renewable energy sources, what will be needed is primarily a park of flexible power plants, where flexibility is defined as the ability to run in partial load as well as by parameters such as ramping rates, start-up time and minimum down time. In all thermal power plants partial load operation is restricted by minimum power generation levels .
Among the various possible conventional electricity generation options (natural gas, coal, nuclear and oil), natural gas seems to be the fuel better placed to play a key role complementary to wind and PV in the decarbonisation path for the following four reasons:

**1)** First of all, natural gas-fired power plants can provide the flexible back-up capacity needed in a system with a high share of variable renewable energy sources. Among conventional electricity generation technologies pumped storage is the most responsive one, as it can be called upon to generate electricity almost instantaneously and as it can ramp up and down by more than 40% of the nominal output per minute. However, being contingent on specific geographical conditions, pumped storage cannot provide the flexible back-up capacity needed at system level. Among other technologies, combined-cycle gas turbines (CCGTs) are particularly suitable for load-following operation as they have both fast load gradients (4%/minute) and can be brought online fairly quickly (less than 1.5 hours from warm conditions). These performance levels are far beyond those of coal-fired power plants (which are less responsive than any other technologies) and of nuclear power plants (which cannot be brought online from cold and warm conditions in timeframes similar to those of other technologies). For this reason, natural gas-fired power plants can well play an important role in meeting the flexibility challenge arising from variable renewable energy sources (Eurelectric, 2011).

**2)** By displacing coal in the EU electricity generation systems natural gas has the potential to generate immediate and substantial GHG emission reductions. In fact, modern CCGTs produce about half the CO2 emissions per unit of electricity generated compared with coal-fired plants (IEA, 2011).

Considering that coal still plays a key role in the EU electricity system the scale of this switch might provide a consistent contribution to the EU 2030 GHG emissions reduction target.

**3)** A switch from coal-fired to natural gas-fired power plants will not only positively impact the EU environmental effort at macro level (i.e. climate change mitigation) but also at micro level. In fact, compared with coal and oil, natural gas avoids or reduces much of the local environmental damage arising from fossil-fuel use. Gas gives off fewer pollutants when burned, including the nitrogen oxide (NOx) that contributes to acidification and ground-level ozone formation; the Sulphur dioxide that (with NOx) causes acid rain; and the particulate matter that (again with NOx) causes smog and poor air quality. Consequently, using natural gas instead of other fossil fuels in electricity generation (and other sectors) offers the opportunity to improve air quality, especially in and around cities, where this problem is most acute.

**4)** Being the second-largest emitter of CO2 after the electricity generation sector, the transport sector has an important role to play in the EU decarbonisation path. GHG emissions from the transport sector have fallen since 2007 due to high oil prices, increased efficiency of passenger cars and slower growth in mobility. The European Commission expects this trend to continue but this will still not be sufficient to meet the goal to reduce GHG emissions from the sector by 60% by 2050 compared to 1990 and by 20% by 2030 compared to emissions in 2008 as set by the Transport White Paper (European Commission, 2011b) adopted in 2011.

Notwithstanding their current difficulties (e.g. relatively high costs, low energy density of batteries and lack of recharging infrastructure), electric vehicles will most likely play a key role in the future decarbonisation of the transport sector. However, natural gas can also play a role in the field, not only by the use of compressed natural gas (CNG) vehicles, but particularly of liquefied natural gas (LNG) for trucks and for ships. For instance, even if it might be difficult to see a significant role for natural gas as a transportation fuel for light-duty vehicles (as CNG vehicles cost more than comparable gasoline-powered cars, have a shorter driving range due to CNG's lower energy intensity, and the development of a large network of easily accessible refuelling stations remains challenging), it is possible to see a significant development in the use of LNG for trucks, as LNG-fuelled long-haul trucks have the capacity to travel up to 1,200 km between fill-ups while pulling heavy loads. Fuel cost savings could recoup the higher investment costs for an LNG truck within about three years. The same rationale also applies to LNG-fuelled buses.

LNG is also expected to play an important role as a shipping fuel. The key driver behind the choice of LNG as shipping fuel relates to its environmental advantages. In fact, ships are generally fuelled by highly polluting fuels such as heavy fuel oil, marine gas oil or distillate fuels. The utilization of LNG allows a significant reduction of local pollution, and thus to safeguarding the ecosystems on which ships are operating. This is the reason why the use of LNG as a shipping fuel is increasingly encouraged by the authorities of major European harbours, from Rotterdam to Hamburg, from Antwerp to Bremerhaven.

## 2.5 Conclusions: Towards a balanced and secure EU decarbonisation path

As illustrated in this chapter, over the last decade the EU has made progress in the decarbonisation of its energy system. However, this process has also brought new challenges to the EU energy markets, generating certain paradoxes (such as the parallel growth of renewable energy and coal in the mix) that need to be addressed in order to ensure the sustainability of the EU decarbonisation path.

Considering that after the first ramp-up phase over the last decade the future integration of more variable renewable energy sources into the system will be more complex both under the technical and economic perspectives, the EU decarbonisation path should find a balanced and secure trajectory. Particular attention should be given to the development of flexibility options (i.e. network infrastructure expansion, development of smart grids, adoption of demand side measures and development of energy storage technologies) that will be crucial to ensure the sustainability of the EU decarbonisation path beyond the 2030 horizon.

Given its previously illustrated characteristics, and particularly taking into consideration the potential to generate immediate and substantial GHG emissions reductions by displacing coal, natural gas might play a significant role in the next decade to accompany the EU in its decarbonisation path.

Chapter 3

# South East Gas Market and Prices: A Country-level Analysis

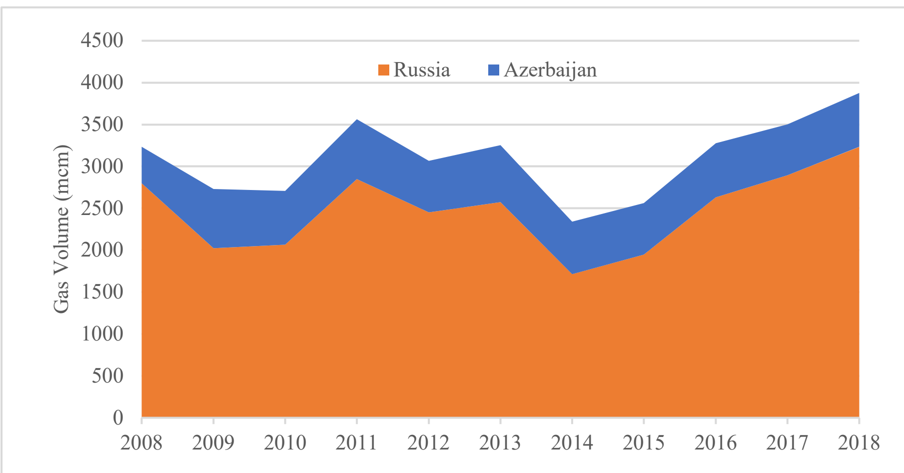
# 3. South East Gas Market and Prices: A Country-level Analysis

by Dr. Kostas Andriosopoulos[3]

## 3.1 Greece

Greece is the only country in the Balkan region, excluding Turkey, that has the facilities to import gas in two forms, via pipeline or via LNG. The production of natural gas in Greece is negligible, just 22.1 ktoe in 2007 decreasing to 9.6 ktoe in 2016 (Eurostat, 2019). In 2008 the country imported 4.2 bcm, reaching the lowest point in imports in 2014, with just 2.9 bcm, reflecting the economic crisis that hit the country, but since then imports have increased by almost 65%, to 4.9 bcm in 2018. The evolution of the quantities imported is shown in the two following graphs.

***Figure 11. Imported Volumes of Gas by Pipeline in Greece***




***Sources: Eurostat, Author's calculations***

Greece imports pipeline gas from Russia and Azerbaijan. Imports from Russia have never been less than 75% of the total imported pipeline gas, reaching as high as 86% in 2008. In 2018 the Russian gas imported was about 3.2 bcm and the Azeri 0.6 bcm making a total of 3.8 bcm of imported pipelined gas.

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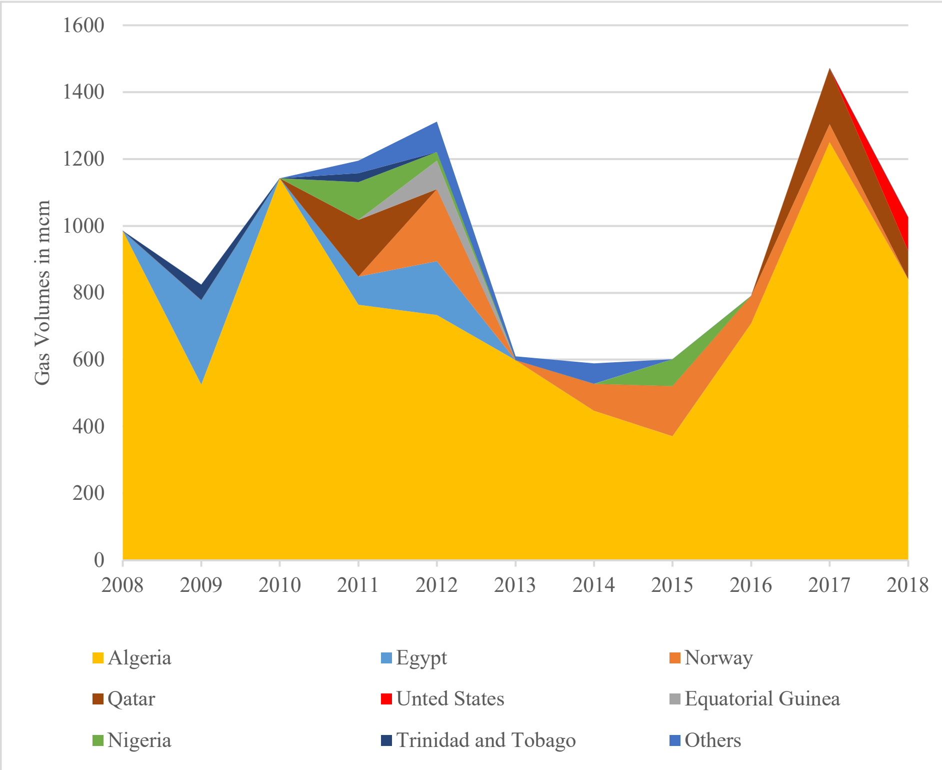
*Figure 12. Imported Volume of Gas in LNG form in Greece*[4]

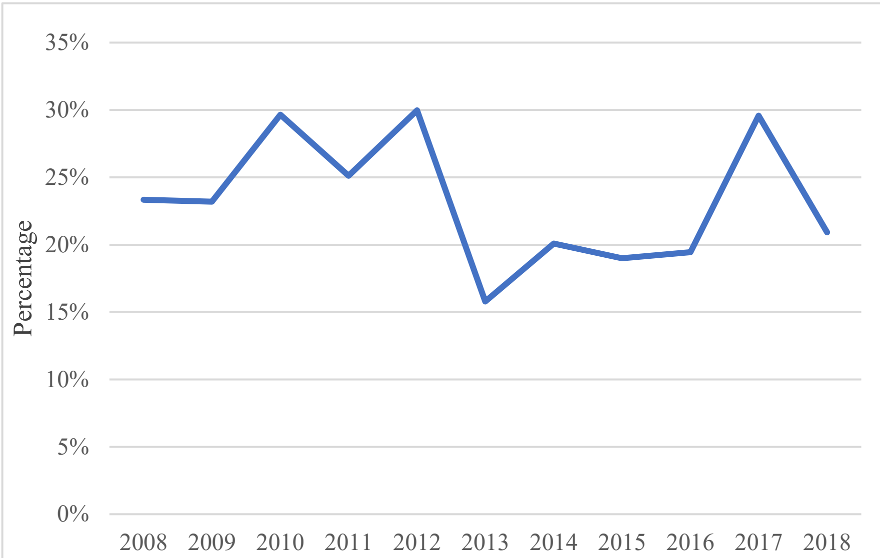



***Sources: Eurostat, Author's calculations***

On the other hand, the group of LNG trade partners is more diversified, which is normal due to the nature of the LNG trade. LNG imports were about 1 bcm in 2008, falling to 0.6 bcm for the years 2012,2013 and 2014 and reached a ten-year period high in 2017 with almost 1.5 bcm. The major country of origin for LNG has been Algeria. In the years 2011 and 2012 we can witness the greatest variety of trade partners. That could be an implication of the Fukushima accident and the worldwide change in the terms of LNG trade. Another important point is that 2018 was the first year that Greece imported US LNG.

[4] Others include: Spain, Italy and Belgium

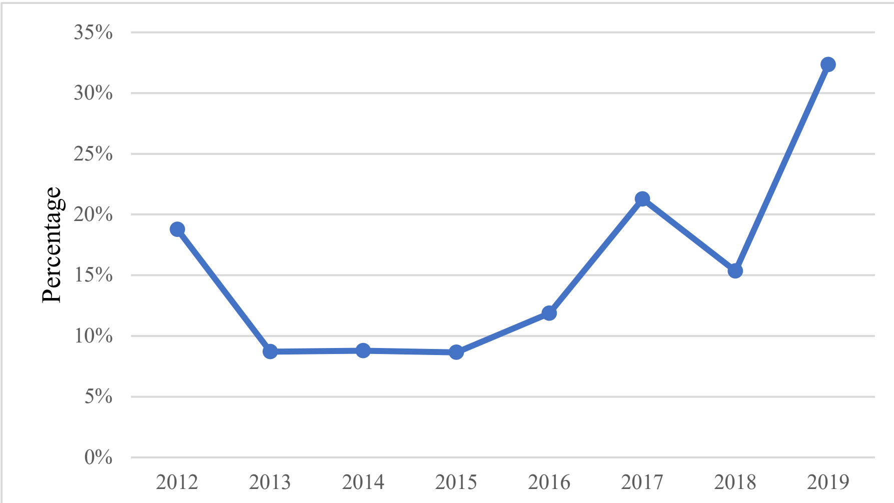
***Figure 13. Percentage of Total Imported Natural Gas in the form of LNG in Greece***




***Sources: Eurostat, Author's calculations***

The percentage of total imported gas in the form of LNG has ranged from 15% in 2013 up to 30% in 2010, 2012 and 2017. Another important aspect is that after the completion of the upgrade in the regasification facilities in the Revythousa terminal with the construction of a third LNG storage tank and the increase in the regasification rate and the output rate in 2018, the terminal has entered a new phase. It is important to notice that in the first six months of 2019 the gas that has been inserted into the grid from the terminal was 1 bcm, which is equal to the total for the whole of 2018. At the same time, the pipeline gas imports were almost 1.5 bcm. It is clear that if this trend continues throughout the year, the final LNG percentage of total imports will reach a new historical peak at 40 %. It is clear from Figure 14 that the utilisation rate of the facility has increased dramatically to reach almost 33% in 2019.

***Figure 14. Regasification Capacity Utilisation rate of the LNG Import Facility in Revythousa***

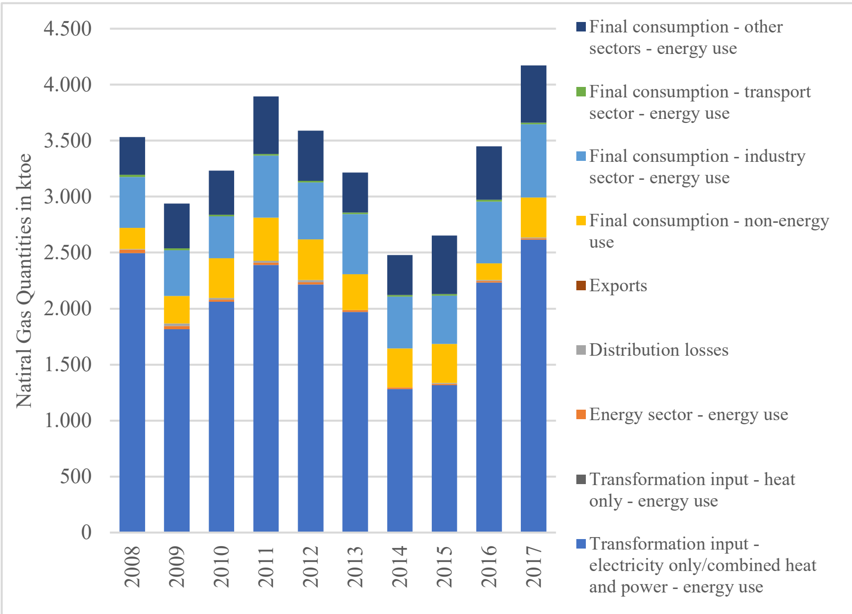



***Sources: ALSI (2019), Author's calculations***

An important project that has been included in the third PCI list is the project of the construction of an additional regasification terminal in Northern Greece. More precisely the addition of an FSRU is planned that will moor close to the port of Alexandroupolis. The project's location is critical as it is close to other gas transmission systems, the interconnector Greece-Bulgaria and TAP. That will provide the possibility for interconnection of the above-mentioned systems and flow of gas from one system to another (Gastrade, 2019b). The first market test was completed in December 2018 and was considered successful since there has been an initial Expression of Interest for a total of 12.2 bcm of regasified gas per year, while the project's regasification capacity is scheduled to be 6 bcm per year with a total storage capacity of 170,000 cubic meters of LNG. The second phase of the market test is set to be concluded in the first months of 2020 and the Final Investment Decision to be taken in the first half of 2020. The completion of the works and the commercial start-up is scheduled for 2022 (Gastrade, 2019a).

Figure 15 shows the final use of natural gas in Greece. It is evident that the majority of the gas is used for power and heat generation, the lowest percentage being 50% of the total gas consumption in 2012. In 2017, the figure was 62%.

***Figure 15. Natural Gas Quantities used in Greece by Sectorial End-Use (in ktoe)*** [5]




***Sources: Eurostat, Author's calculations***

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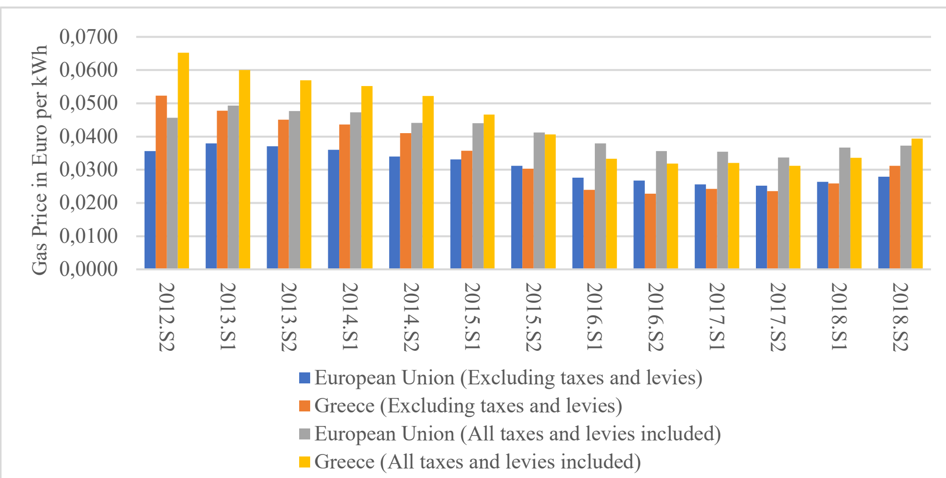
[5] According to Eurostat (2019) the following are defined as follows. The **Transformation input** covers all inputs into the transformation plants destined to be converted into derived products. Transformation is only recorded when the energy products are physically or chemically modified to produce other energy products, electricity and/or heat. It includes*:* ***Transformation input - electricity only/combined heat and power - energy use*** and ***Transformation input - heat only - energy use****.* **Energy sector-energy use** includes the consumption of own-produced energy and of energy purchased by energy producers and transformers in operating their installations. In detail it includes: *Own use in electricity & heat generation, Coal mines, Oil & natural gas extraction plants, Patent fuel plants, Coke ovens, BKB & PB plants, Gas works, Blast furnaces, Petroleum refineries (oil refineries), Nuclear industry, Coal liquefaction plants, Liquefaction & regasification plants (LNG), Gasification plants for biogas, Gas-to-liquids (GTL) plants, Charcoal production plants, Not elsewhere specified (energy).* **Distribution losses**: This category includes quantities of fuel losses which occur during transport and distribution, including pipeline losses. **Exports** represent all exits from the national territory excluding transit quantities. In **Final consumption** are included: **Final consumption - non-energy use** and **Final consumption - energy use**. *In* **Final consumption - non-energy** are included*: Non-energy use industry/transformation/energy, Non-energy use in transport sector, Non-energy use in other sectors. In the final consumption - energy use is included: Final consumption - industry sector - energy use, Final consumption - transport sector - energy use and Final consumption - other sectors - energy use. In Final consumption - industry sector - energy use is included: Iron & steel, Chemical & petrochemical, Non-ferrous metals, Non-metallic minerals, Transport equipment, Machinery, Mining & quarrying, Food, beverages & tobacco, Paper, pulp & printing, Wood & wood products, Construction, Textile & leather, Not elsewhere specified (industry).* In **Final consumption - transport sector - energy use** is included: *Rail, Road, Domestic aviation, Domestic navigation, Pipeline transport, Not elsewhere specified (transport)*. In **Final consumption - other sectors - energy use** is included*: Commercial & public services, Households, Agriculture & forestry, Fishing, Not elsewhere specified (other)*

The final energy consumption of the industry sector has ranged from 12% to 18% during this decade, settling at 15.5% in 2017. The iron and steel, the non-metallic minerals and the petrochemical industries are the most significant users of natural gas for energy. The consumption of natural gas in the transportation sector is negligible with less than 1% of the total consumption to be accredited to road transportation. "Other sectors" account for the remaining 10% to 15% of gas consumption. In 2017 9% was the percentage of the energy use in households and 4% the use for commercial and public services.

Figures 16 and 17 depict the evolution of natural gas prices for selected groups of households and non-household consumers. The different bands refer to bands of consumption which are defined for non-household consumers as Consumption Band I3 with annual consumption between 10,000 and 100,000 GJ and for household consumers as Consumption Band D2 with annual consumption between 20 and 200 GJ.

***Figure 16. Evolution of Gas Prices in EU-Greece for Non-Household Consumers, Band I3 (Euro/kWh)***

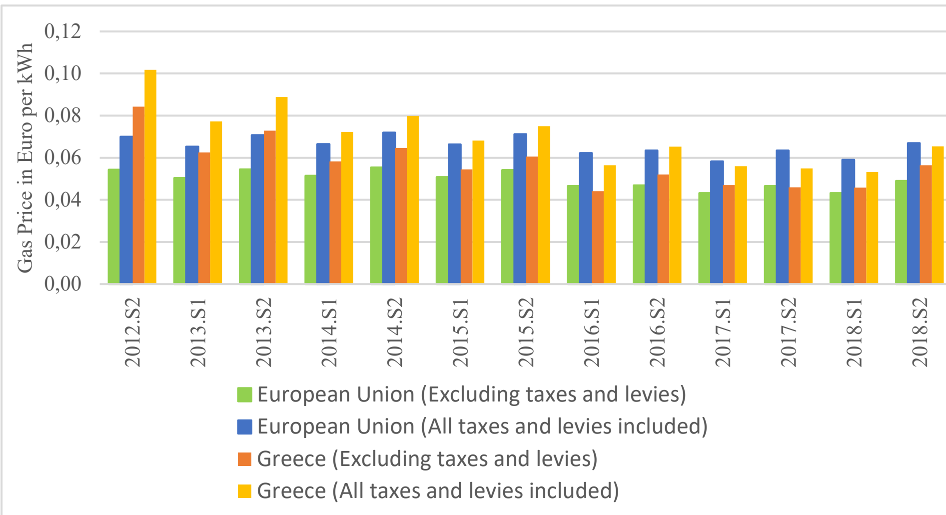



***Sources: Eurostat, Author's calculations***

The price of gas for non-household consumers in Greece in the second semester of 2012 was 0.0652 Euro/kWh, with 20% of that being taxes and levies, while in the EU the average price was 0.0456 Euro/kWh, with a tax component of 22%. The prices in Greece after 2012 have decreased continuously up to 2017 reaching the lowest price of 0.0312 Euro/kWh including taxes of 24.2%, and then slightly increasing to 0.0394 Euro/kWh even though the tax percentage has decreased to 20.8%. A similar trend is observed also in the EU average gas price.

A similar trend is observed also for the price to household consumers. In 2012 Greek households were paying a price for gas significantly higher than the average EU price. By the end of 2018 this has been reversed. Greek households are paying lower prices than the average EU household. A significant parameter can be the fact that the taxes and levies that the Greek household pay was for 2018 around 14% of the total price while in the EU average this was around 27% of the final price.

***Figure 17. Evolution of Gas Prices in EU-Greece for Household Consumers, Band D2 (Euro per kWh)***

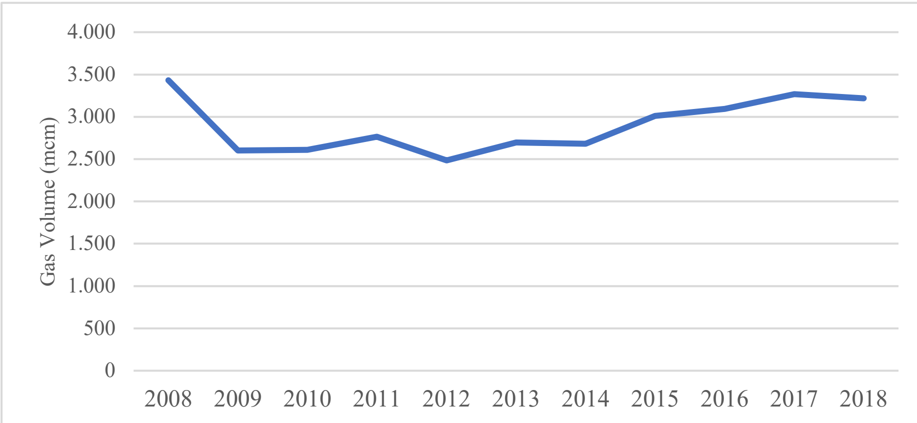



***Sources: Eurostat, Author's calculations***

## 3.2 Bulgaria

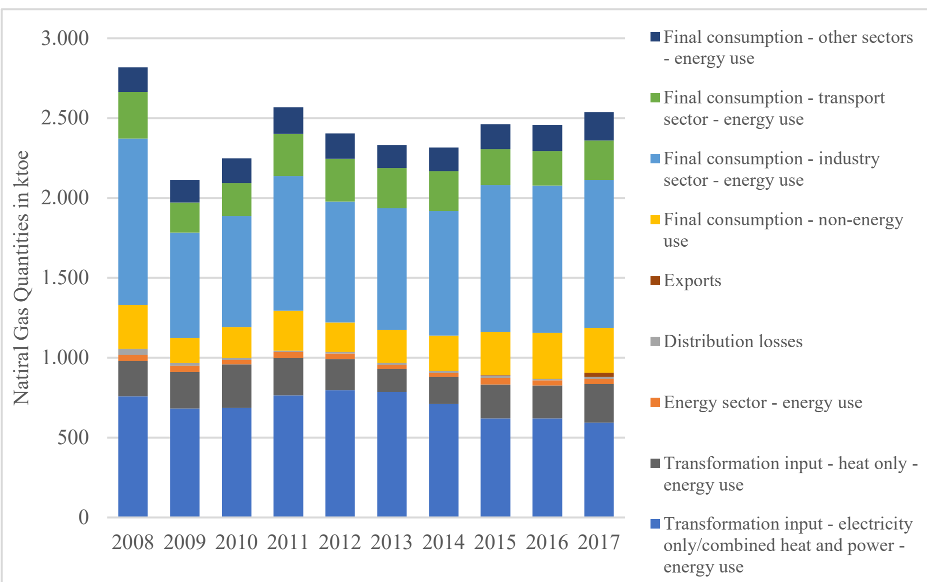
Bulgaria has a small production of natural gas. It was 235 ktoe in 2017, decreased to 13 ktoe in 2009, peaked at 350 ktoe in 2011 and after that it decreased once more to 77 ktoe in 2017 (Eurostat, 2019) The national gas transmission network is built in a ring-shaped form of high-pressure gas pipelines with a total length of 1835 km. Its technical transport capacity amounts to 7,4 bcm per year. In addition to that there is a gas transmission network for transit transmission towards Greece, Turkey and North Macedonia. That network has a total length of 930 km and a transport capacity of 17.4 bcm per year (BULGARTRANSGAZ, 2019). Its only gas imports are from Russia, as shown in Figure 18.

*Figure 18. Imported Natural Gas in Bulgaria from Russia*




***Sources: Eurostat, Author's calculations***

*Figure 19. Natural Gas Quantities used in Bulgaria by Sectorial End-Use (in ktoe)*



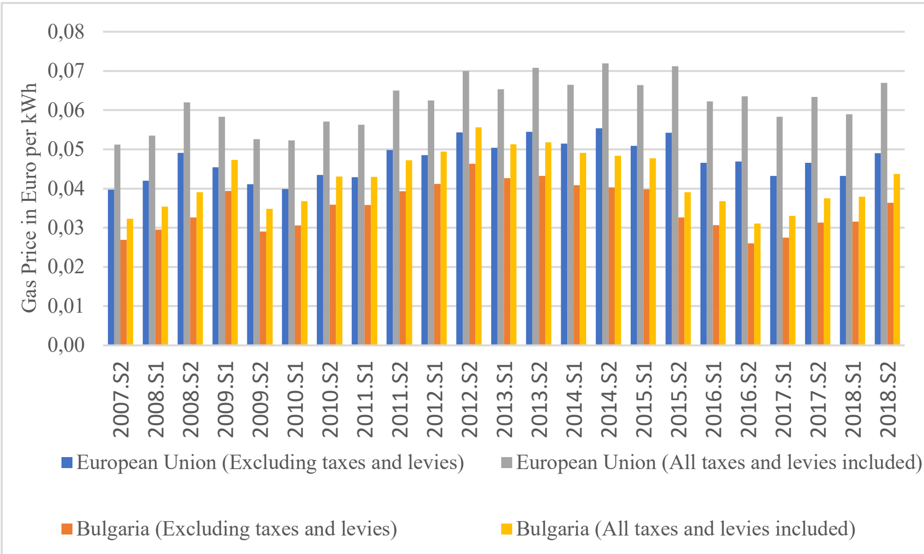

***Sources: Eurostat, Author's calculations***

Bulgarian imports have been between 2.5 and 3.5 bcm/year since 2008. ENTSO-G security of supply scenarios show that Bulgaria would be exposed to natural gas shortages in the event of a disruption in the supply of Russian gas through the Balkans and Ukraine (ENTSO-G, 2017d). This is one of the reasons that Bulgarian authorities are trying to diversify their suppliers and the routes the they get their gas.

Figure 19 shows the final uses of natural gas in Bulgaria. Contrary to Greece, the percentage used for electricity and combined power and heat generation was only 22% in 2017 from a high of 31% in 2012. Also, around 10% has been used only for the production of heat. Another 10% of natural gas consumption was used for non-energy use of the energy and industrial sector. The remaining 50% is used for final energy use consumption. The final energy consumption of the industry sector has ranged between 22% and 35% in the past ten years, settling at 32.4% in 2017. The chemical and petrochemical and the non-metallic minerals industries have been relatively stable at around 10% each. On the other hand, the iron and steel industry has collapsed from 7.5% in 2008 to just 1.5% in 2017. The consumption of natural gas in the transportation sector is around 10% of the total consumption, with most of that gas being used for the transportation of the gas itself, through the country. Finally, other sectors represent around 5% of gas consumption. In 2017 3% was the percentage of the energy use in use for commercial and public services and only 2% the use of gas in households.

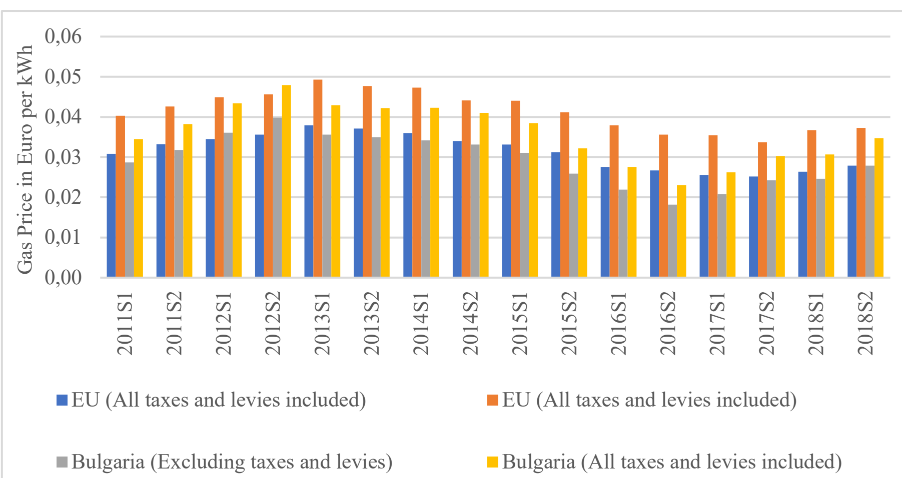
In Bulgaria, the prices for household consumers have always been lower than the average EU price. The price in 2007 was at 0.0323 Euro/kWh, when the EU price was 0.0512 Euro/kWh. It peaked in the second semester of 2012 at 0.0556 Euro/kWh, while the EU price was 0.0700 Euro/kWh and then fell to 0.0437Euro/kWh at the end of 2018, while the EU price was 0.0670 Euro/kWh. One element that is worth noting is that the taxes and levies component in the prices in Bulgaria has been stable at 16.5% of the total price.

***Figure 20. Evolution of Gas Prices in EU-Bulgaria for Household Consumers, Band D2 (Euro per kWh)***




***Sources: Eurostat, Author's calculations***

***Figure 21. Evolution of Gas Prices in EU-Bulgaria for Non-Household Consumers, Band I3 (Euro/ kWh)***




***Sources: Eurostat, Author's calculations***

Gas prices for non-household consumers have also been lower than the EU average throughout the period of study. Taxes and levies have been less than

20% in the majority of the semesters for Bulgarian prices, contrary to the EU prices that are often above 25%.

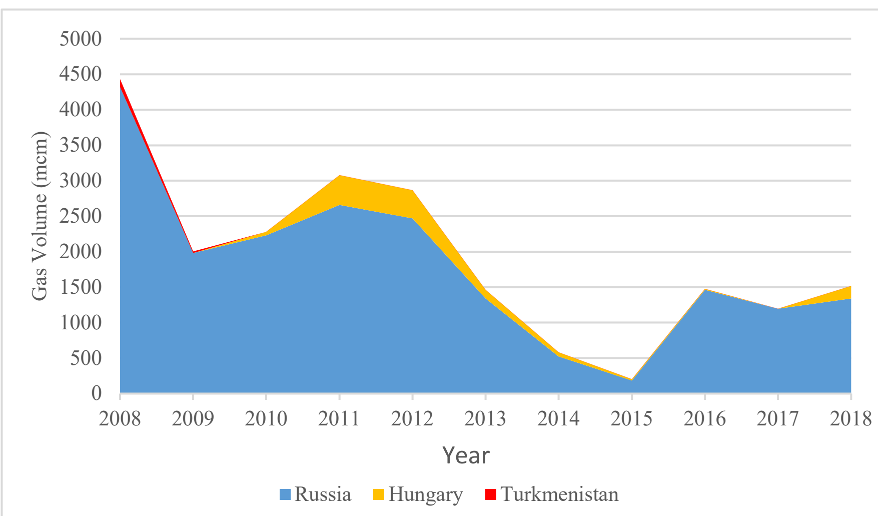
## 3.3 Romania

Transgaz is a state-owned company, which is the technical operator of the national natural gas transmission system in Romania. The company handled in 2017 a quantity of 12.87 bcm of natural gas. The company has a total transport capacity of 30 bcm of natural gas and a pipe network of 13,000 km, of which 553km are transit pipelines (ANRE, 2018).

Romania has the highest natural gas production of the ten countries in SE Europe. It has constantly produced more than 10% of the total natural gas produced in the European Union in the last ten years. Its production though is declining, from 9,232 ktoe in 2007 to 7,784 ktoe in 2016 (Eurostat, 2019).

Most of Romania's gas imports come from Russia, as is shown in Figure 22.

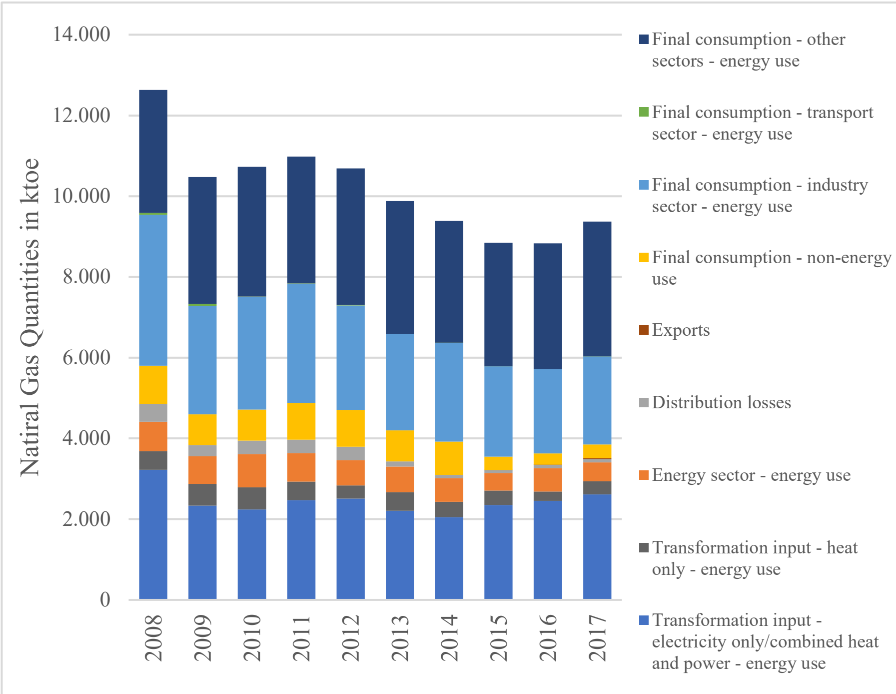
***Figure 22. Volumes of Imported Natural Gas in Romania (by Country Trade Partner)***




***Sources: Eurostat, Author's calculations***

The imports of gas into Romania have two separate phases. In the first phase from 2008 to 2015 we have a significant decrease in natural gas imports from around 4.4 bcm in 2008 to only 0.2 bcm in 2015. Since then we observe an increase again in the imports, reaching 1.5 bcm in 2018. Of course, that quantity is only one third of the quantity imported only a decade ago.

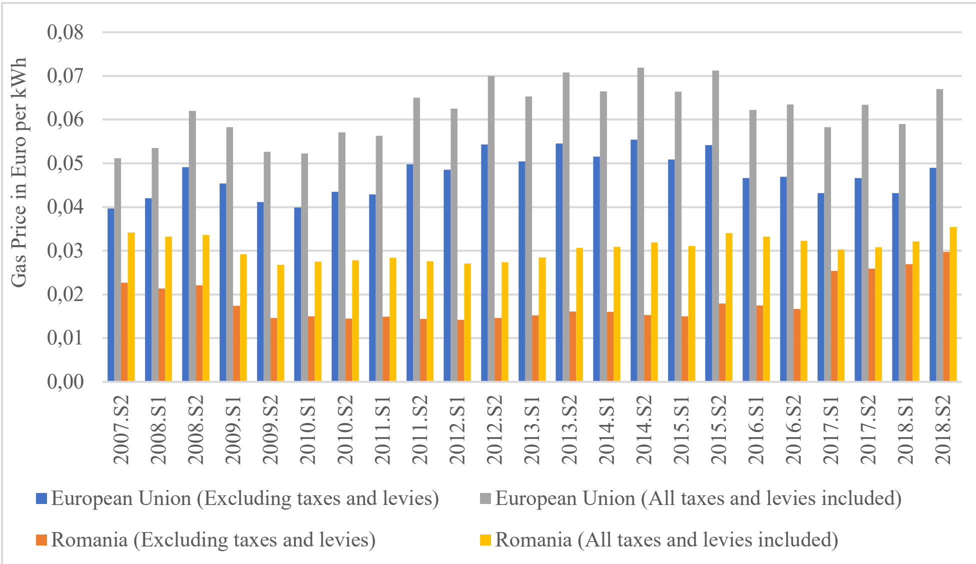
***Figure 23. Natural Gas Quantities used in Romania by Sectorial End-Use (in ktoe)***




***Sources: Eurostat, Author's calculations***

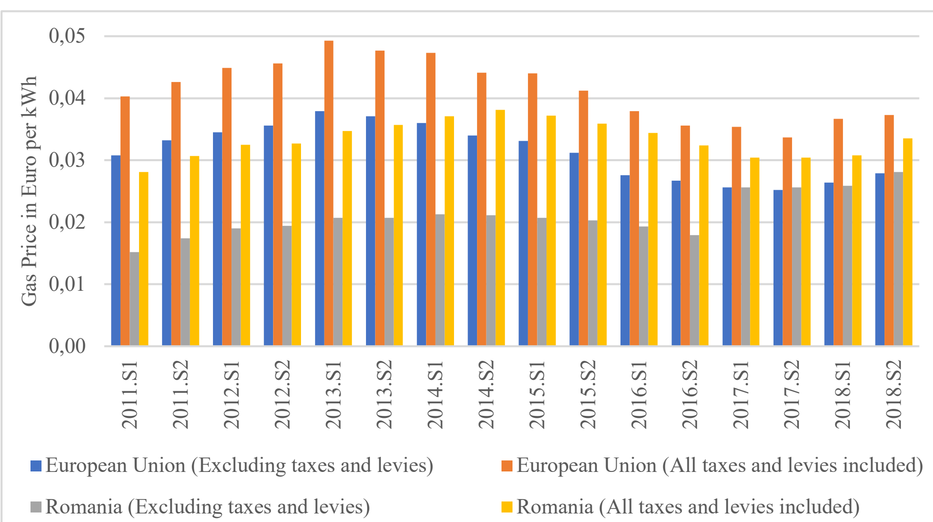
The use of gas has decreased by almost 25% in the last decade in Romania, from 13,048 ktoe in 2008 to just 9,641 ktoe in 2017. The percentage for electricity production and cogeneration of heat and power was 27% in 2017 and for heat only was 3%, summing up to about 30%, which is the maximum percentage for these activities over the past decade. The energy use of the energy sector has been around 5-6% during the examination period, with distribution loses falling from 3.5% in 2008 to just less than 1% in 2017. The final non energy consumption of the energy and industry sector was halved from 7% in 2008 to less than 4% in 2017. The final energy use of the industry sector has decreased from 28% in 2008 to just 22% in 2017. The fall has been greatest in the chemical and petrochemical sector, from 11.1% in 2008 to 6.1% in 2017. The iron and steel industries follow with another 5%. The transportation sector is just 0.5% of the total gas consumption. There is a significant increase in household use, from 16% in 2008 to 25% in 2017. The energy consumption in commercial buildings was 8% in 2017.

*Figure 24. Evolution of Gas Prices in EU-Romania for Household Consumers, Band D2 (Euro per kWh)*




***Sources: Eurostat, Author's calculations***

*Figure 25. Evolution of Gas Prices in EU-Romania for Non-Household Consumers, Band I3 (Euro per kWh)*




***Sources: Eurostat, Author's calculations***

Prices in Romania have been very much lower than the average EU gas price. In many cases it has been less than half price. It is very important to note that the tax and levies percentage in the price was very high until 2017, over 40% and reaching 52% the second semester of 2014. The price has been relatively stable ranging from 0.0274 Euro/kWh to 0.0354. The tax percentage has been lowered to almost one third from 2017 settling around 16% of the final price.

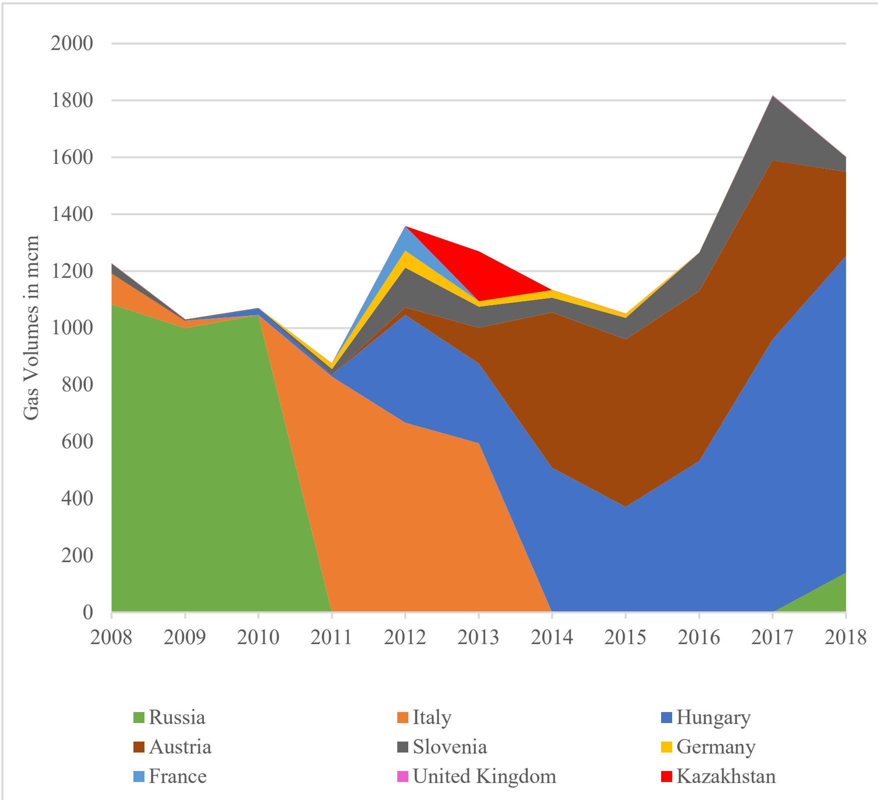
The case is similar for non-household consumers. The price without the taxes and levies component was extremely lower than the EU average for the period up to the first semester of 2017. The taxes and levies percentage was until then in the scale of more than 40% of the final price. In 2017 the price of gas excluding the taxes went up but due to reduction of the taxes by more than half there was not a significant impact in the final price, which at the end of 2018 was closer than ever to the average EU price.

## 3.4 Croatia

In 2008 Croatia produced 2,362 ktoe of natural gas, but production declined to about 1,300 ktoe in 2016 (Eurostat, 2019). As a consequence, it depends more and more on imports. The gas transmission system is 2,662 km long (HERA, 2018).  Croatia was the last country to join the EU in 2013, so it was left behind in the liberalization process and the unbundling of the energy services. Liberalisation started in 2008, but unbundling started in 2010. Croatia imports its gas mainly from Russia, but due to the nature of the contracts that Croatian companies have signed with Gazprom and to the unbundling of the gas industry, the trade importing partners vary a lot. To make it more clear, Croatian companies have signed deals with Gazprom to import Russian gas, but they buy it from the market. One 5-year long contract was signed for 2012 to 2017, and a new 10-year long contract was signed in 2017. The imported volumes were around 1.1-1.2 bcm until 2017 when they reached 1.8 bcm.

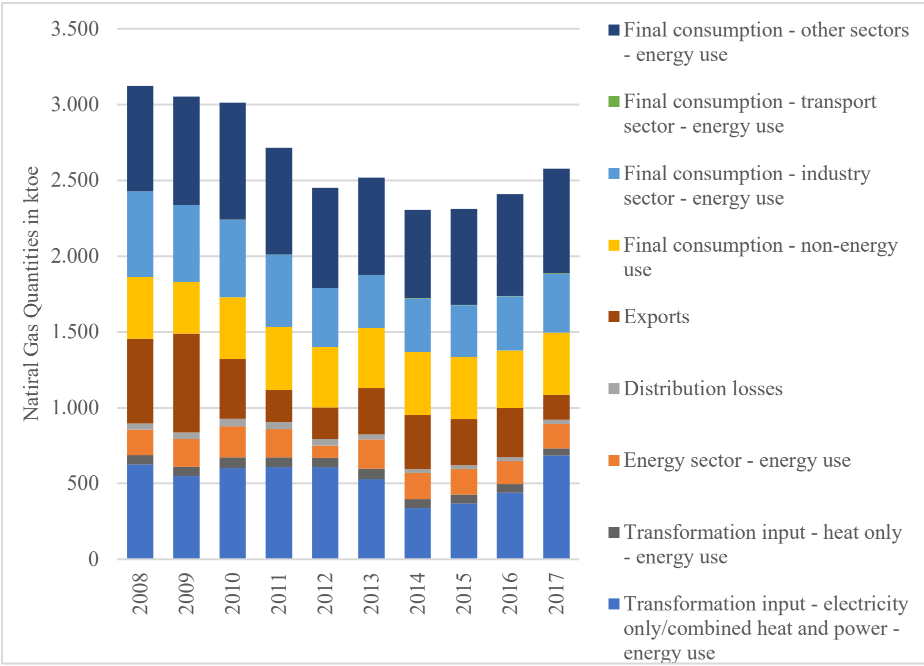
Croatia is set to build an LNG facility at the island of Krk to diversify its suppliers of natural gas. The project has been funded by the EU and it in the PCI list. It involves the construction of a Floating Storage and Regasification Unit (FSRU) and all the needed pipeline network for its connection to the Croatian gas transmission system. The final investment decision was taken in January 2019. The total budget of the project is around €230 million of which the EU has provided around €100 million. The regasification capacity of the FSRU is expected to be 2.6 bcma at maximum rate, in the first stage of the project (LNG Croatia LLC, 2019).

*Figure 26. Volumes of Imported Natural Gas in Croatia (by Country Trade Partner)*




***Sources: Eurostat, Author's calculations***

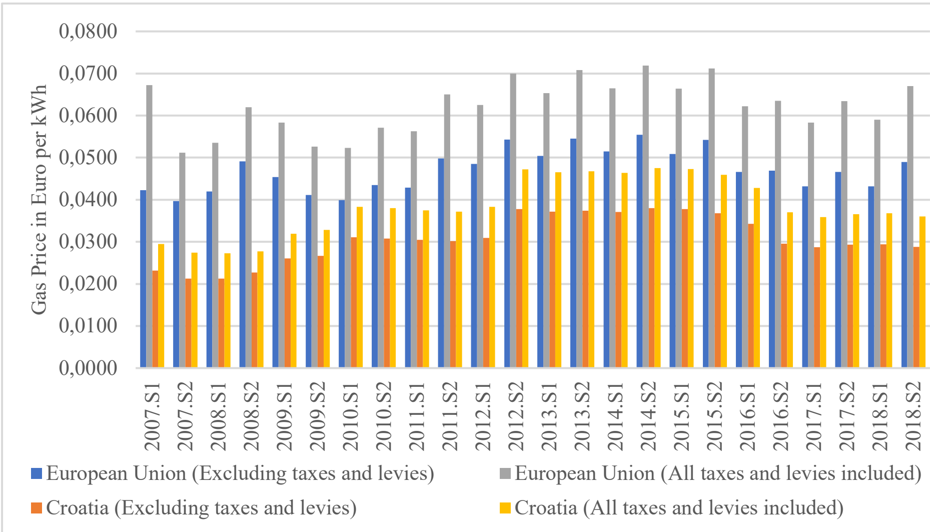
***Figure 27. Natural Gas Quantities used in Croatia by Sectorial End-Use (in ktoe)***




***Sources: Eurostat, Author's calculations***

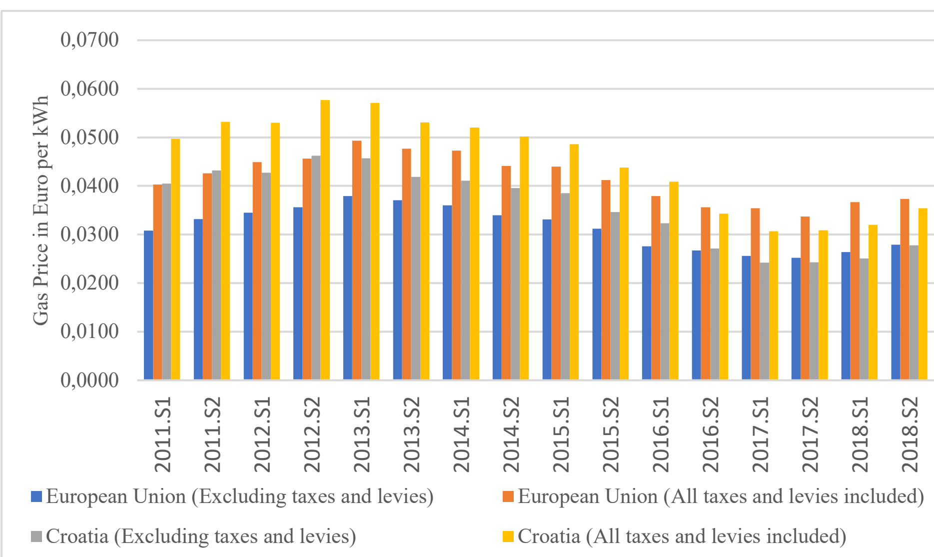
Consumption in Croatia has decreased from over 3,100 ktoe in 2008 to over 2,500 ktoe in 2017. Out of that, the percentage for electricity production and cogeneration of heat and power was ranging from 14% in 2014 to 25% in 2017 and only for heat was 2%. A significant portion of the natural gas is exported. In 2008 and 2009 the exports were close to 20% of the total available gas in the country. But in 2017 the exports accounted for only 6% of the natural gas. The energy use of the energy sector has been around 6-7% during the examination period. The final non energy consumption of the energy and industry sector deviated from 11% in 2011 to 15% in 2017. The final energy use of the industry sector was rather at stable around 15%. The non-metallic minerals sector is leading with 5% in 2017, followed by the food and beverage and chemical and petrochemical industries with around 3% each. The use of gas in the transportation sector is almost zero. On the other hand, the use in the households is at 17% in 2017 while the percentage of the consumption for energy in commercial buildings raised from 4% in 2008 to 7% in 2017.

***Figure 28. Evolution of Gas Prices in EU-Croatia for Household Consumers, Band D2 (Euro per kWh)***




***Sources: Eurostat, Author's calculations***

***Figure 29. Evolution of Gas Prices in EU-Croatia for Non-Household Consumers, Band I3 (Euro/kWh)***



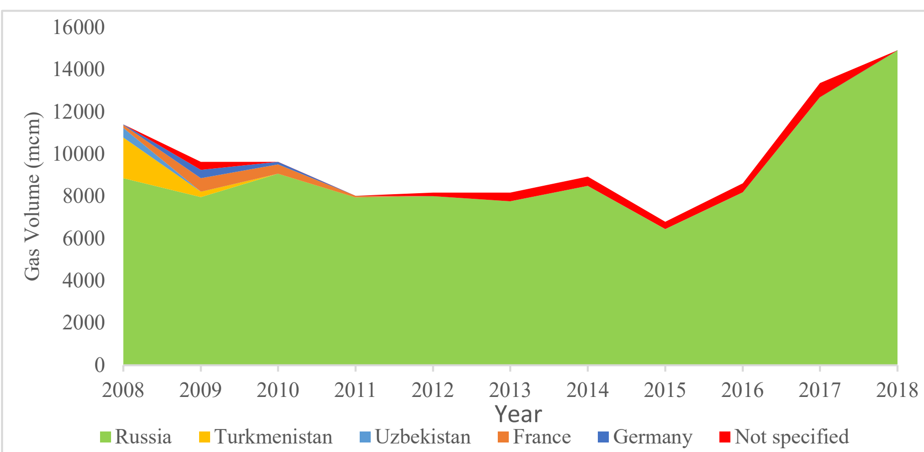

***Sources: Eurostat, Author's calculations***

The final prices in Croatia have been following the market trends on the price of natural gas since the tax and levies percentage has been relatively stable around 20%. The prices have been significantly lower than the EU average price for the household consumers. On the contrary the prices for the non-household consumers has been higher than the average EU price until the second semester of 2016. Since then, the price in Croatia is lower than the average EU price and lower than the price in 2011. The tax burden has increased slightly from 18% in 2007 to 21% in 2018.

## 3.5 Hungary

Hungary has an almost identical natural gas production profile with Croatia. In 2007 it produced around 2,000 ktoe of natural gas but in 20016 the produced volume was decreased by 25% at 1,400 ktoe (Eurostat, 2019). Hungary is one of the largest natural gas markets in the Balkan peninsula. To cover its needs, it is importing large volumes of gas. The largest trade partner is Russia. The operation of the 5782 km long system was performed by two operators until 2019. FGSZ Földgázszállító Zrt signed the purchase agreement of Magyar Gáz Tranzit Zrt (MGT). With this transaction, the 92km long Hungarian-Slovak interconnector gas pipeline will be owned by FGSZ, thus FGSZ will manage and control the whole Hungarian high-pressure natural gas transmission system from the 4th of October 2019 (FGSZ, 2019). To cover its needs, it is importing large volumes of gas. The largest country's trade partner is Russia.

***Figure 30. Volumes of Imported Natural Gas in Hungary (by Country Trade Partner)***

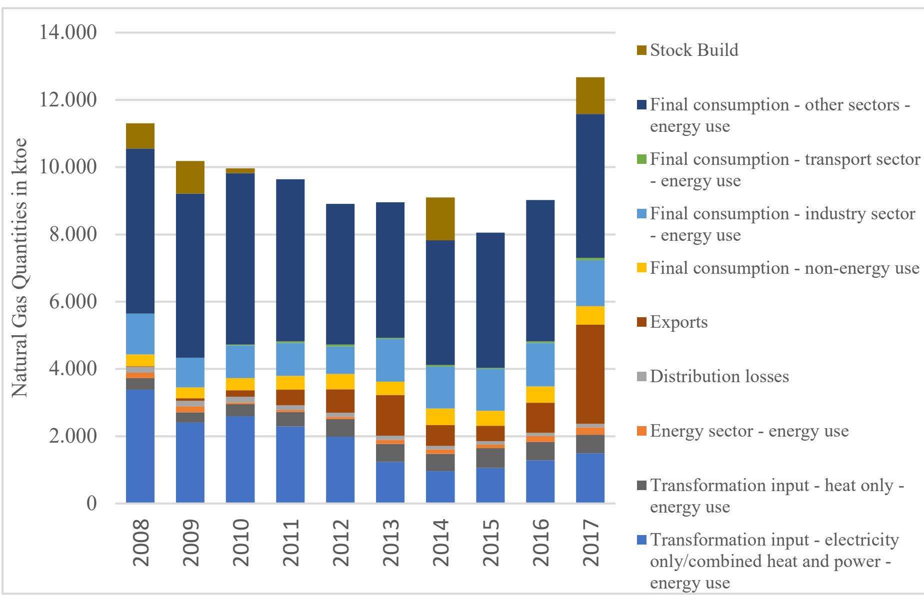



***Sources: Eurostat, Author's calculations***

In 2008, Hungary imported more than 11 bcm of natural gas, primarily from Russia, then in 2015, the imports fell to less than 7 bcm to more than double this number in three years' time, reaching almost 15bcm of imports in 2018. The gas is mainly Russian either entering the gas system from the east in the borders with Ukraine or entering through the entry point in the west in the orders with Austria. The composition of both these entry points shows that the origin of the gas is Russia.

In Hungary there is a recent change in the use of natural gas. The use of natural gas for the power generation and the cogeneration of heat and power has been decreased from almost 30% of the total use in 2008 to just over 10% in 2017. In absolute numbers, 3.5 bcm were used in 2008 for that use, only 1bcm in 2014 and 1.5 bcm in 2017. On the other hand, gas was used in 2008,2009, 2014 and 2017 in order to fill the Hungarian gas storages.

***Figure 31. Natural Gas Quantities used in Hungary by Sectorial End-Use (in ktoe)***

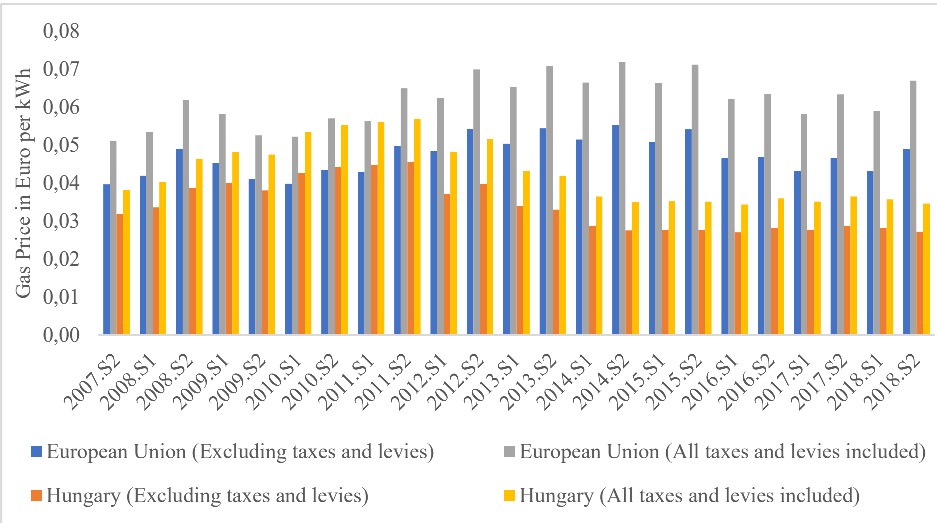



***Sources: Eurostat, Author's calculations***

A very important element is the energy use of gas in the other sectors, particularly the household sector, where around 3 bcm is used per year and the commercial and public services sector that uses 1.5 bcm per year on average. These two sectors add to almost half of the total consumption in some years, like 2009-2011 and 2015.

Another element worth noting is that in 2017 the exports have been almost 23% of the total available natural gas for that year, reaching 3 bcm, from 0.2% in 2008. The final non energy use has been relatively stable around 5% in the past decade. The final energy consumption of the industrial sector has been around 1 bcm, reaching a high of 1.3 in 2017, with the chemical and petrochemical industry, the food, beverage and tobacco industry and the non-metallic minerals industries being the top three consuming industries with around 2% of the total consumption each. The use of gas in the transport sector is less than 1% in the total gas consumption.

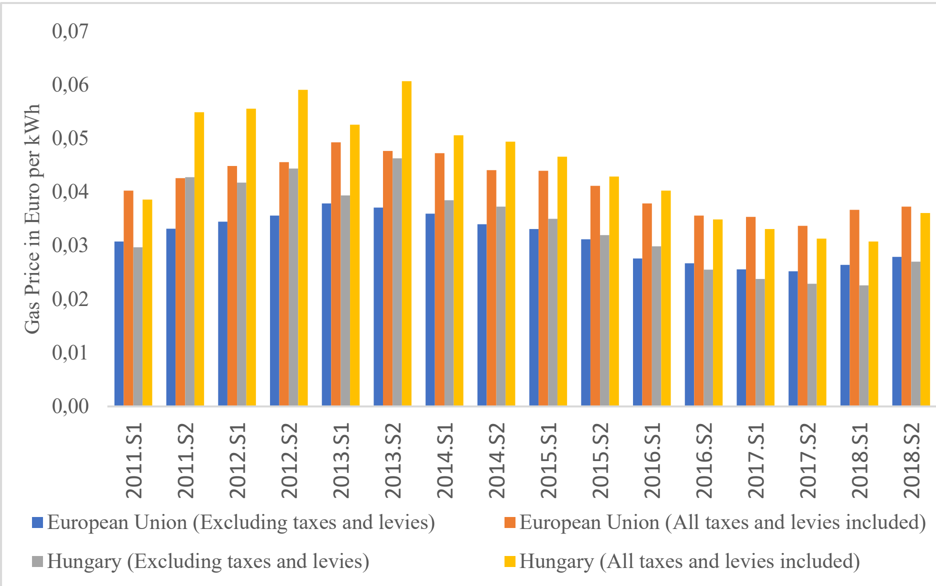
***Figure 32. Evolution of Gas Prices in EU-Hungary for Household Consumers, Band D2 (Euro per kWh)***




***Sources: Eurostat, Author's calculations***

The average price that the Hungarian households are paying has always been lower than the EU average price and that gap grew further after 2012. The tax and levies component of the price has been at 16% in 2007 and grew up to 23% in 2012 and landing at 21% in 2018.

*Figure 33. Evolution of Gas Prices in EU-Hungary for Non-Household Consumers, Band I3 (Euro/kWh)*




***Sources: Eurostat, Author's calculations***

On the contrary the prices for non-household consumers have been higher than the EU average in the period from the second semester of 2011 up to the second semester of 2016. Since then the y have been almost at par with the EU average. The tax percentage has been higher than that of the household consumers, starting at 23% in 2011, reaching 28% in 2017 and finally 26% in 2018.

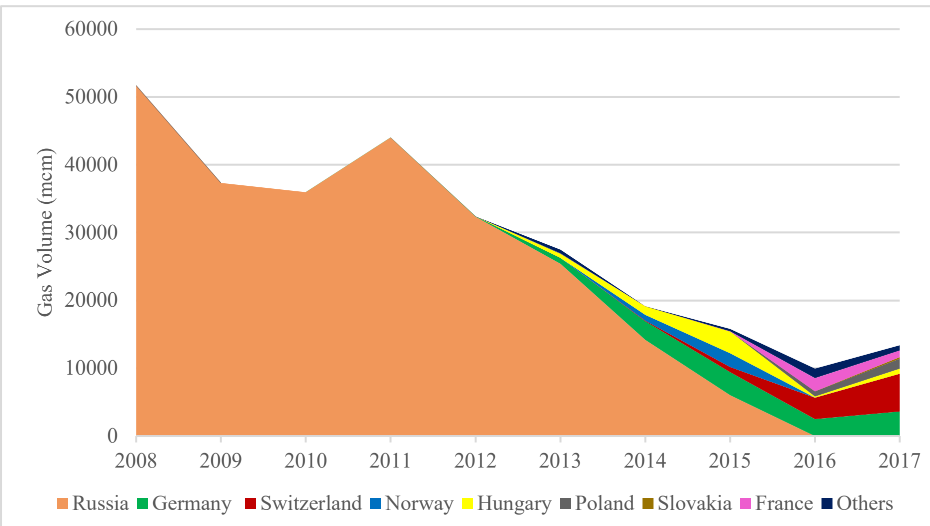
## 3.6 Ukraine

Ukrainian gas transmission system is one of the largest in the world in terms of its transportation capacities. The total length of gas transmission pipelines in Ukraine is 38,500 km. Over 40% of natural gas supplies from the Russian Federation to European countries were delivered through Ukrainian gas transmission system in 2018 and 2017 (Naftogaz, 2018).

Ukrainian gas transportation system includes 12 underground gas storage facilities located in mainland Ukraine and one is in the Crimea region that has been under Russian control. The total capacity of the underground gas storage system located in Ukraine is 31 billion cubic meters of gas. As of 2018, the system had import capacity of 292.3 billion cubic metres and export capacity of 178 billion cubic metres per year.

In 2018 gas imports from the EU comprised 10.6 bcm, or 24.8% less year-over year. Of these volumes, 61% were imported from Slovakia, 32% from Hungary and 7% from Poland. In 2018, the volume of Russian gas transit through Ukraine amounted to 86.8 bcm, which was 6.7 bcm less than in 2017. Ukraine is producing around 15,000 ktoe of natural gas per year the past decade but has been also a large importer of gas the previous decade (Eurostat, 2019). Mainly the gas was imported from Russia but due to the crisis in the relationship between the two countries, this trade partnership has ended in 2015.

***Figure 34. Volumes of Imported Natural Gas in Ukraine (by Country Trade Partner)[6]***

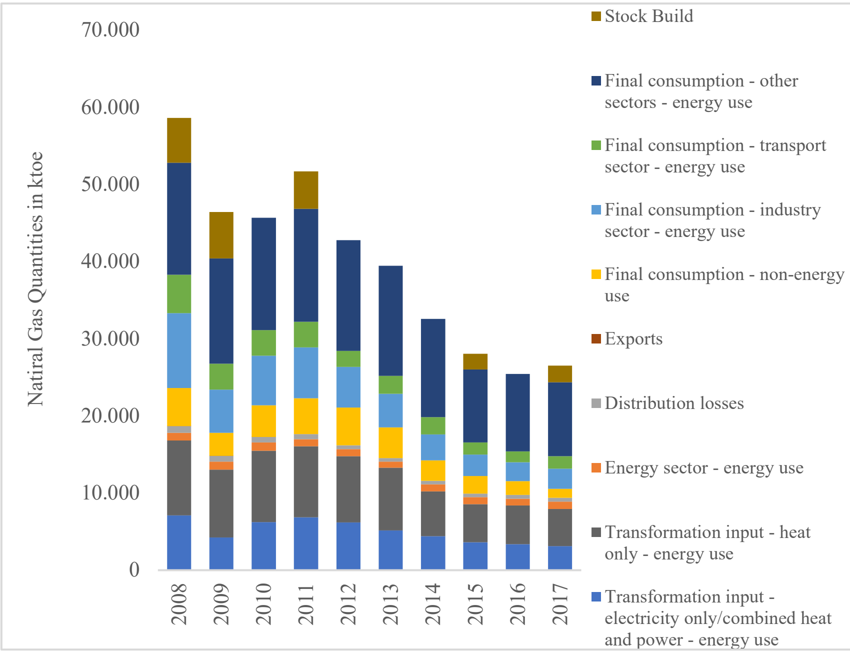



***Sources: Eurostat, Author's calculations***

We can see from the diagram above that in 2008 Ukraine imported almost 50 bcm of natural gas from Russia. This amount of gas imports was a peak for the past decade. In 2015 the total imports of gas in Ukraine was just 13 bcm. Since 2015 Ukraine is not importing any gas from Russia. It is importing its gas from its partners in the west. Of course, many of these countries are not producing these volumes of gas in their territories but they are redirecting gas, perhaps of Russian origin, to Ukraine through their territories.

[6] Others include Czech Republic, Italy, Luxemburg, Malta, Austria and the United Kingdom

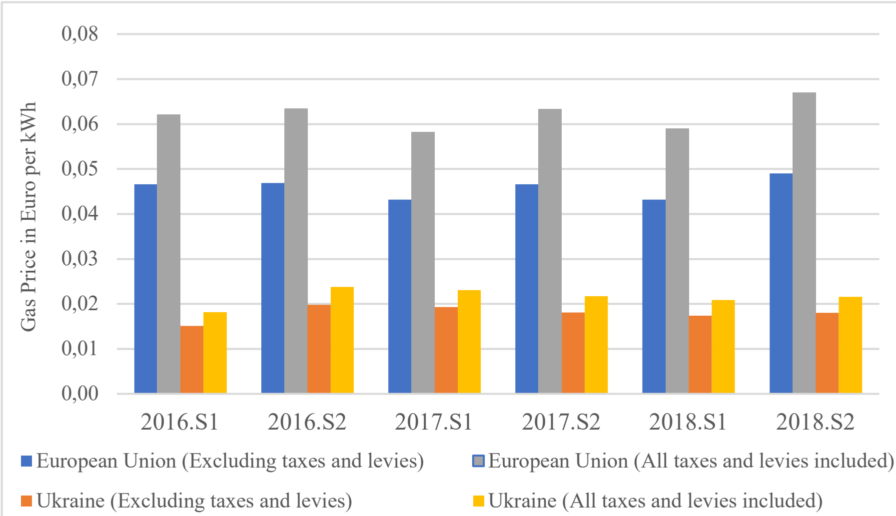
*Figure 35. Natural Gas Quantities used in Ukraine by Sectorial End-Use (in ktoe)*




***Sources: Eurostat, Author's calculations***

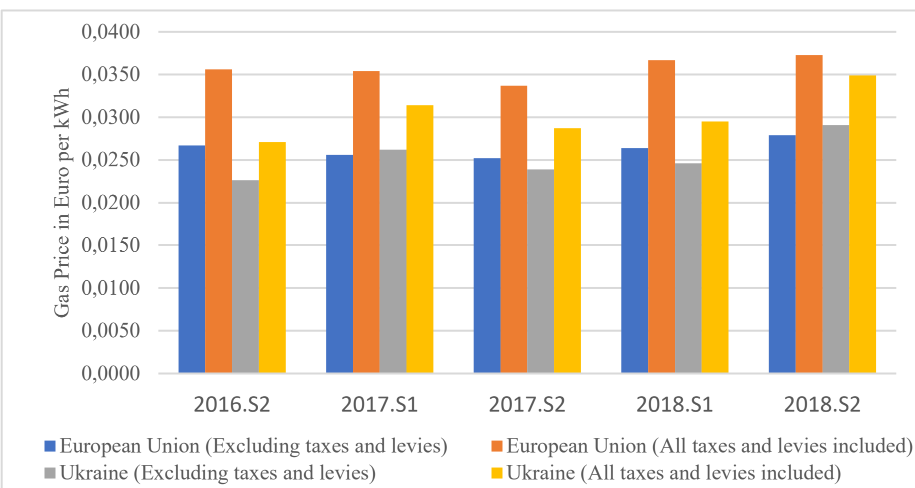
It is worth noting that the gas market has shrunk almost at half during this decade. From almost 60,000 ktoe in 2008, it became a less than 30,000 ktoe market in 2017. Especially in the first years of the crisis in 2008 and 2009 a significant volume was used to fill the natural gas storages and the same thing happened in 2011, 2015 and 2017. The use of gas for electricity and cogeneration of heat and electricity was around 12% and the use for heat generation was around 18% of the total consumption of gas. The use of gas in the industry has more than halved from 18% of the total consumption in 2008 to just 8% in 2017, with the iron and steel industry to be the major consumer with almost 5% of it. The transportation sector uses another 8% of the total gas consumption with the majority of that to be used in the pipeline transportation. Finally, the final consumption of other sectors, has increased its percentage from 25% in 2008 to 35% in 2017, especially the households have increased the use of gas from 23% to 33%.

*Figure 36. Evolution of Gas Prices in EU-Ukraine for Household Consumers, Band D2 (Euro per kWh)*




***Sources: Eurostat, Author's calculations***

*Figure 37. Evolution of Gas Prices in EU-Ukraine for Non-Household Consumers, Band I3 (Euro/kWh)*




***Sources: Eurostat, Author's calculations***

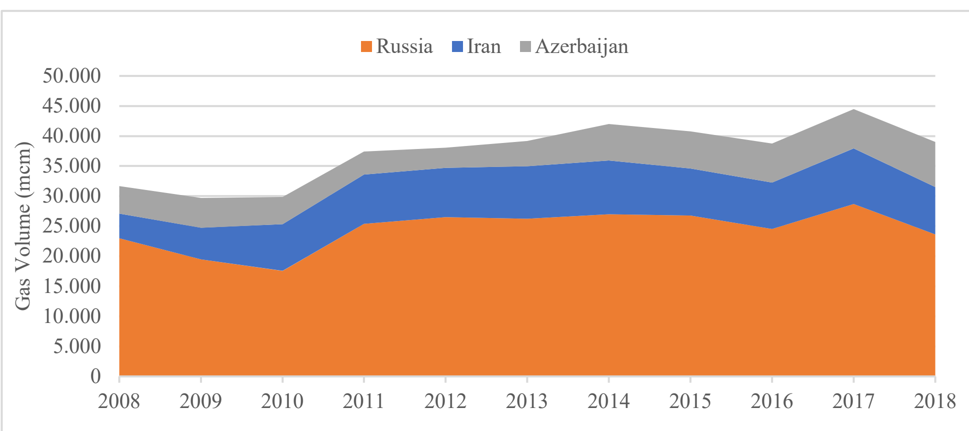
The prices of natural gas in Ukraine have been almost at one third of the average EU price and the tax component has been around 17% of the final price the Ukrainian households have been paying. Contrary to the situation in the households, the non-household consumers were still paying less than the EU average but that difference was at the size of 8.5 euros per MWh in 2016 and reached just 2.4 euros per MWh in 2018.  The tax percentage was stable at 16.5% of the final price.

## 3.7 Turkey

Turkey has a long network of natural gas pipelines. The total length of that network is almost 13.000 km. Also, it has four operational LNG import terminals. The first is Marmara Ereglisi LNG Terminal which started operations in 1994, the second is Ege Gaz A.Ş. LNG Terminal, in Aliaga, which started operations in 2006 and the final two are two FSRUs, the first is situated again in Aliaga, the Aliaga Etki, that was the first FSRU to start operation in 2016 and the last one is the Dortyol FSRU terminal which started operating in 2018 (BOTAS, 2016, BOTAS, 2019, EMRA, 2019) .

Turkey is producing some small quantities of natural gas. In 2007 it produced about 700 ktoe of natural gas but the declining production reached only 300 ktoe in 2016 (Eurostat, 2019). As a consequence, Turkey is importing very large volumes of natural gas in order to cover the needs of its expanding gas market. It is importing gas via pipelines from three countries, primarily Russia, Iran and Azerbaijan.

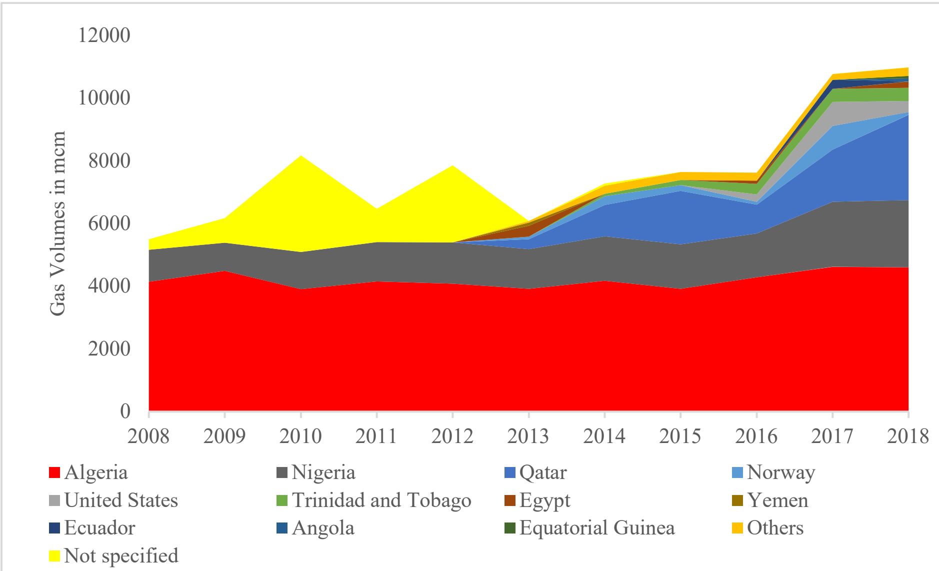
***Figure 38. Imported Volumes of Gas by Pipeline in Turkey***




***Sources: Eurostat, Author's calculations***

In 2008 Turkey imported less than 30 bcm in 2007 by these three countries and a total of 44 bcm in 2017 and 40 bcm in 2018. In 2007 it imported 22 bcm from Russia, 4.1 from Iran and 4.5 from Azerbaijan. In 2018 it imported 23.5, 7.8 and 7.7 bcm from the three countries respectively.

***Figure 39. Imported Volumes of Gas in LNG form in Turkey***[7]

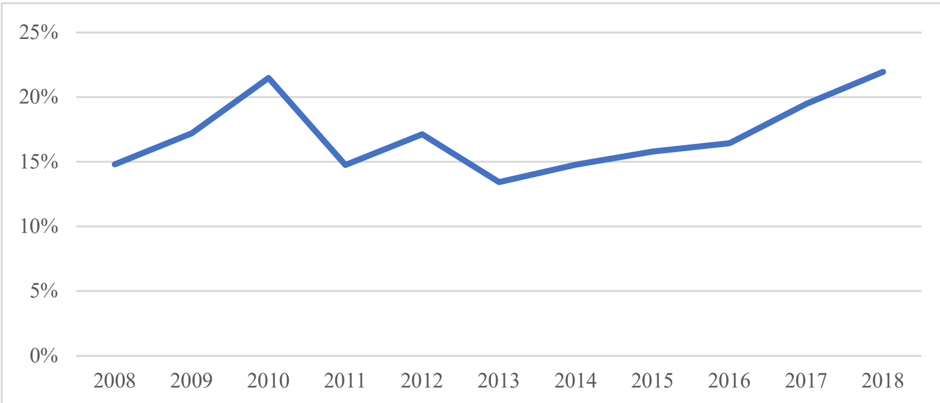



***Sources: Eurostat, Author's calculations***

Up to 2012 the country was importing LNG through long term contracts with Algeria and Nigeria, at the size of 4 bcm and 1.5 bcm annually. Since 2012 it has started to diversify more its LNG suppliers. After the completion of the two new import terminals the imported volume has doubled reaching 11 bcm. In 2016 Turkey has been one of the first countries to receive US LNG cargoes in their terminals.

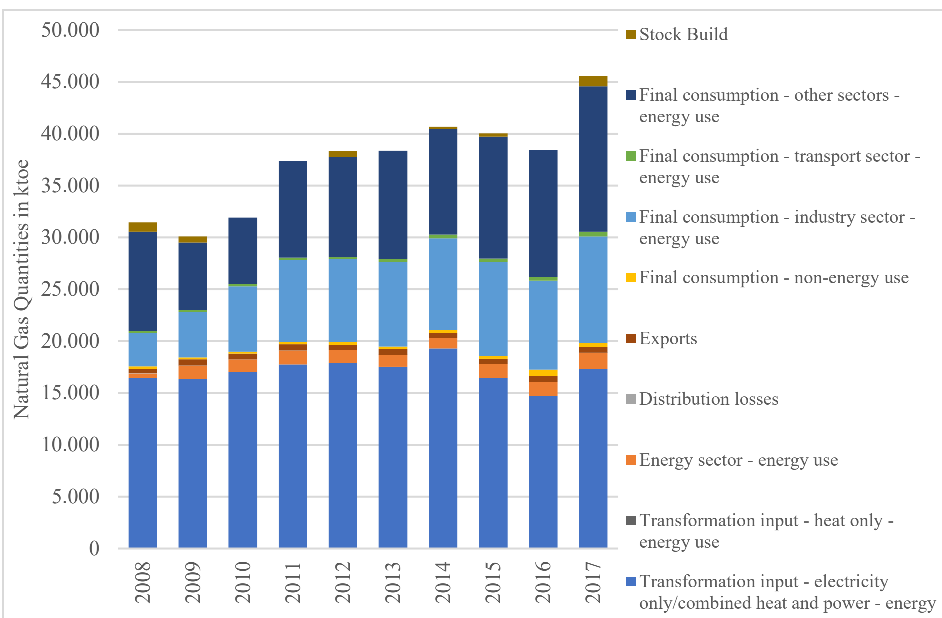
[7] Others include Belgium, Spain, France, Netherlands and the United Kingdom

***Figure 40. Percentage of Total Imported Natural Gas in the form of LNG in Turkey***




***Sources: Eurostat, Author's calculations***

***Figure 41. Natural Gas Quantities used in Turkey by Sectorial End-Use (in ktoe)***



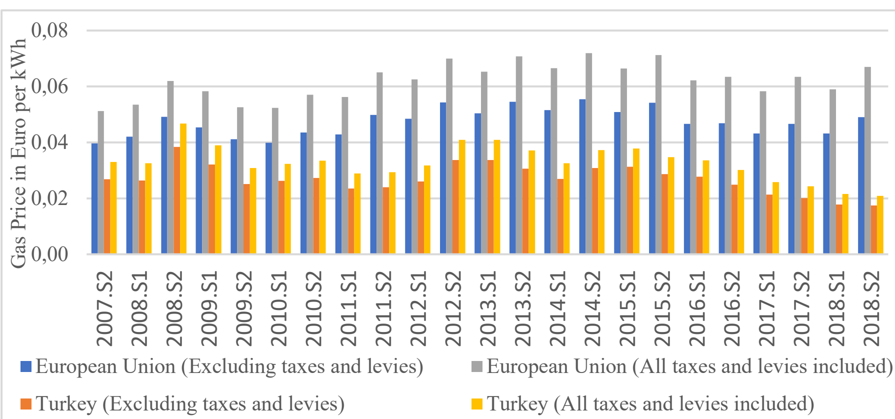

***Sources: Eurostat, Author's calculations***

Despite the increase of the number of the terminals still the volumes of gas imported in the form of LNG are less than 20% of the total imported volumes as we can see in the graph above. It is important however to note that there is a trend to increase the LNG arriving in the Turkish borders starting from 2013 and onwards. In the first 6 months of 2019 the LNG imports were at 7 bcm while the pipelined gas volumes where 16 bcm. This means that the LNG imports correspond to 30% of the total imported volumes in the first semester of 2019.

Turkey's gas market has grown significantly the past decade, with almost 50% increase in 2017 from the 2008 levels. The percentage used for cogeneration of heat and power has decreased from almost 50% in 2008 to 37% in 2017. The energy use in the industry has increased significantly, from 10% in 2008 it reached 23% in 2017. The non-metallic minerals industry and a diverse group of non-specified industries are the most consuming subsectors, with around 4% each. The final energy use of other sectors corresponds to 30% of the total consumption. More specifically in 2017 25% of the total use was from households and 5% from commercial and public services energy consumption.

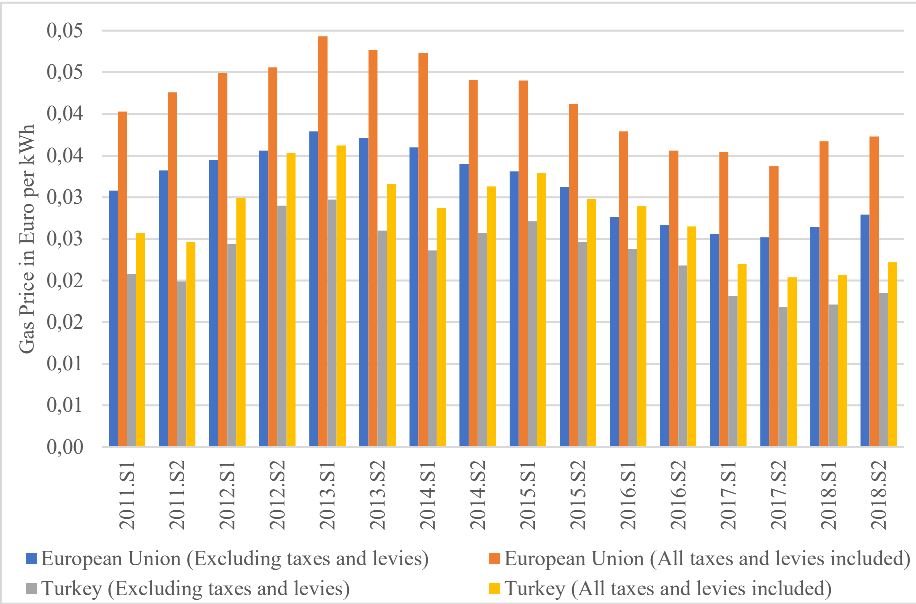
The gas prices that the households are paying have been lower than the EU average. In the last three years the prices are continuously dropping to reach just 2 euros per MWh in the second semester of 2018. The tax percentage of the final price was 18% in 2007 and dropped slightly to 16.5% in 2018.

***Figure 42. Evolution of Gas Prices in EU-Turkey for Household Consumers, Band D2 (Euro per kWh)***




***Sources: Eurostat, Author's calculations***

***Figure 43. Evolution of Gas Prices in EU-Turkey for Non-Household Consumers, Band I3 (Euro/kWh)***




***Sources: Eurostat, Author's calculations***

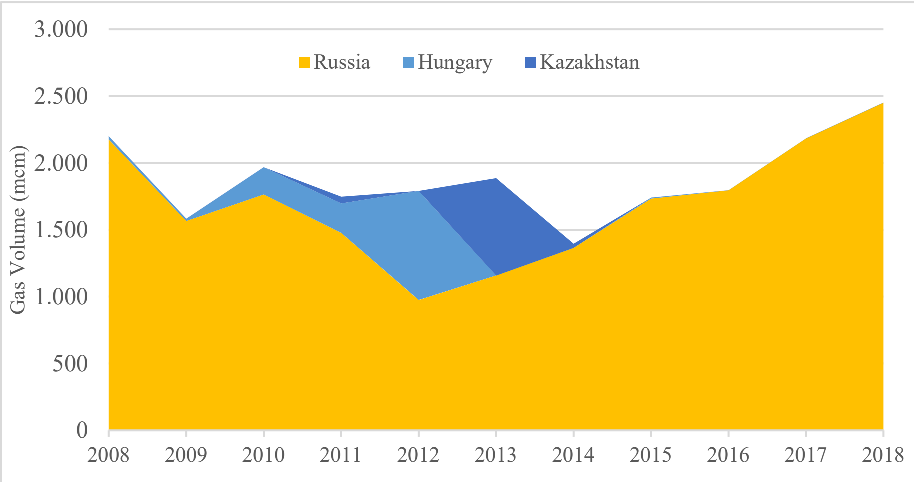
The non-household users face a similar situation. The prices are lower that the EU average and were almost 40% less than the average in 2018. The tax and levies percentage of the final price was at 19.5% in 2011 and it was continuously dropping to reach 17% in 2018.

## 3.8 Serbia

Serbia is another country that produces very little volumes of gas. Despite the fact the production of gas has more than double in since 2007, when the production was 200 ktoe, it reached 420 ktoe in 2016, that is not enough to cover its needs so Serbia imports gas (Eurostat, 2019).

Serbia has two transmission companies, PE Srbijagas and Yugorosgaz-Transport. The length of the transmission system of PE Srbijagas is 2,298 km in northern and central Serbia, and the transmission system of Yugorosgaz-Transport is 125 km in the south-eastern part of Serbia. Both interconnections with Hungary and Bulgaria are part of transport system of Srbijagas, while Yugorosgaz-Transport does not have pipelines connected with transport systems of neighbouring countries (AERS, 2017). In July 15, 2019, the Energy Agency of the Republic of Serbia (AERS) has adopted a Decision on revocation of the certificate issued to the Yugorosgaz-Transport by the Agency Decision of June 20, 2017.

***Figure 44. Volumes of Imported Natural Gas in Serbia (by Country Trade Partner)***



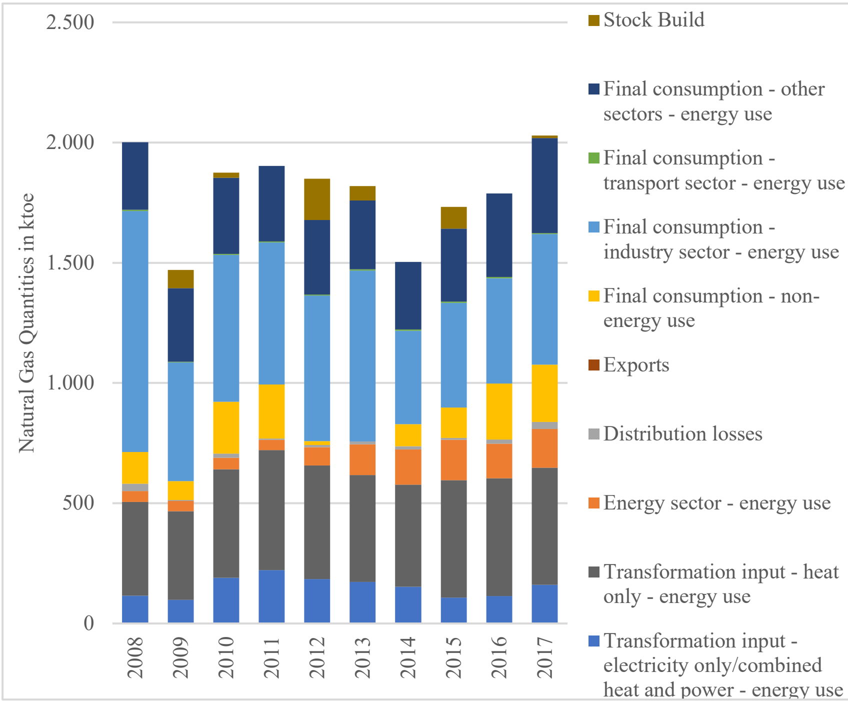

***Sources: Eurostat, Author's calculations***

Serbia has been importing Russian at volumes ranging from 1 bcm to 2 bcm. The lowest point in these imports was in 2012 with only 1 bcm, but since then the imports are increasing again to reach almost 2.5 bcm in 2018.

In Serbia, the electricity and cogeneration of heat and power sectors is using less than 10% of the total available gas. In 2017 it was about 8%. On the contrary the use of gas for heat in district heating is a major consumer of gas ranging from 20% to 26%. In 2017 it was 23% of the total consumption in the country. The use of gas for the own use of the energy sector has increased from 2% in 2008 to 8% in 2018. Another 10% in 2017 was the non-energy use of the industrial sector. The energy use of gas in the energy industry has been reduced sharply. In 2008 is represented almost 50% of the total consumption of gas, with iron and steel industry to be alone 34%.

In 2017 things have altered dramatically. The total sector represented only 25% and the iron industry was only 4% of the total. In 2017 the biggest industrial consumers were the chemical and petrochemical and the food, beverage and tobacco industries with 7% and 5% respectively. The use of gas in the other sectors was ranging from 14% in 2008 to 21% in 2009, settling at 18% in 2017. The household-subsector and the commercial and public services subsector represent 9% each over the total gas consumption.

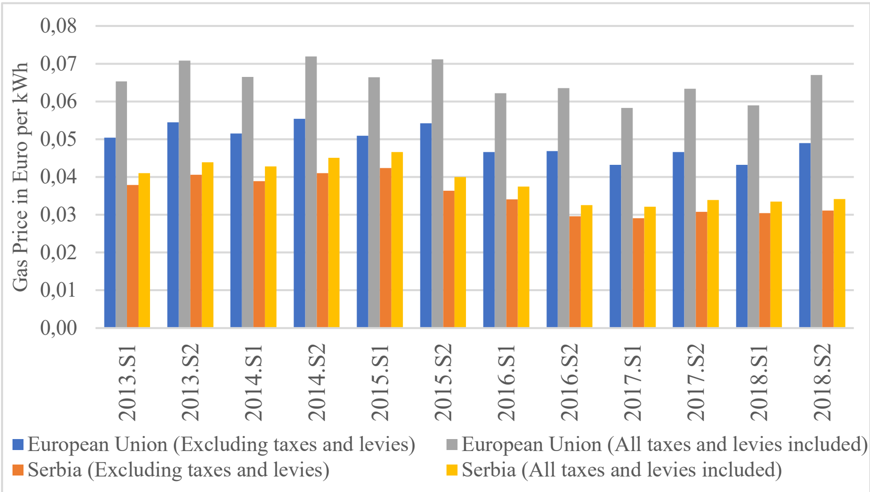
*Figure 45. Natural Gas Quantities used in Serbia by Sectorial End-Use (in ktoe)*




***Sources: Eurostat, Author's calculations***

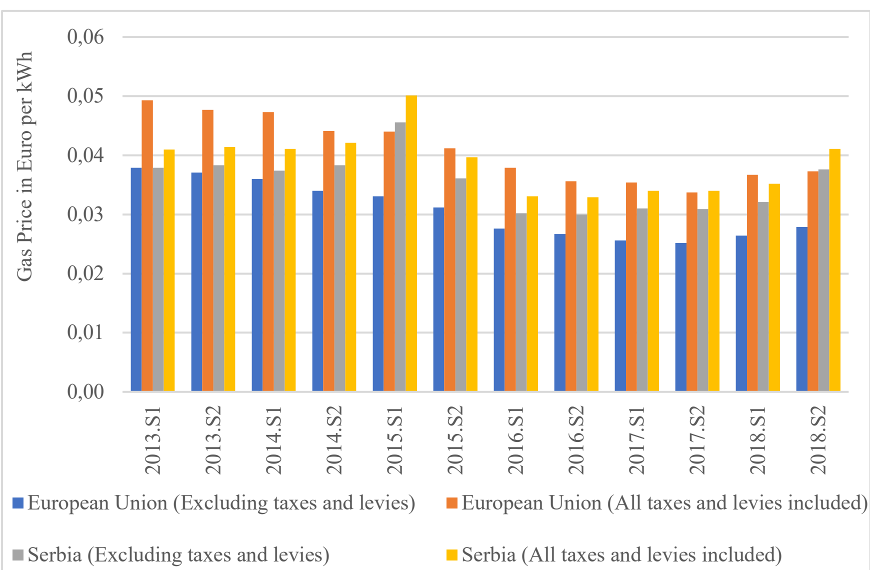
The gas prices for the Serbian household consumers have been falling from 2015 to 2017, but since then they have slightly increased. They have been however always lower than the average EU gas price. The tax component has been as little as 7% in 2013 but it has come up to 9% in 2018. As far as the non-household consumers are concerned, they were paying less than the EU average price with the exception of three semesters, the first of 2015 and the second semesters of 2017 and 2018. The tax component in their case also was less than 10% throughout the examination period, settling around 9% in 2018.

*Figure 46. Evolution of Gas Prices in EU-Serbia for Household Consumers, Band D2 (Euro per kWh)*




***Sources: Eurostat, Author's calculations***

*Figure 47. Evolution of Gas Prices in EU-Serbia for Non-Household Consumers, Band I3 (Euro/kWh)*



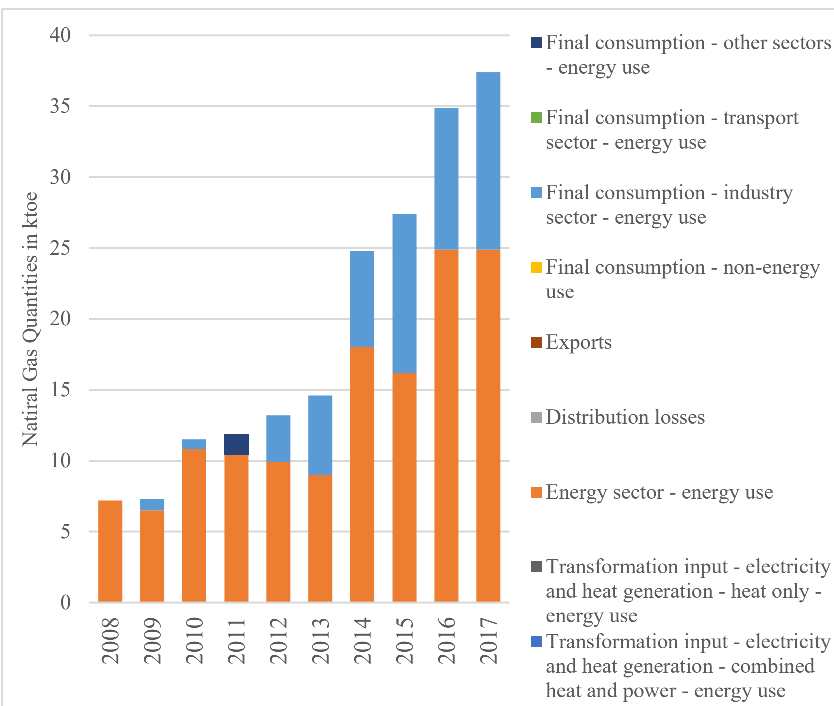

***Sources: Eurostat, Author's calculations***

## 3.9 Albania

Albania is the only European country that is not connected to international natural gas networks. The only gas deliveries are from the gas fields to big industrial customers. Albgaz JSC administers about 500 km of gas pipelines (ERA,2016). The production of gas was 7 ktoe in 2007 and 37 ktoe in 2017 (Eurostat, 2019). The optimal way for Albania to connect to the international gas network is that of the gas pipeline transit or "TAP" project. Further gas infrastructure and market developments in Albania will also be closely linked with the implementation of other projects envisaged by the Gas Master Plan, including the Ionian Adriatic Pipeline (IAP), the construction of a potential liquefied natural gas (LNG) and gas storage facilities as well as the refurbishment of the internal gas pipeline network (Energy Community, 2019).

The majority of the gas is used for the energy needs of the energy sector itself. From 2009 and onwards a part is from the food and beverage industry and other non-specified industries.

***Figure 48. Natural Gas Quantities used in Albania by Sectorial End-Use (in ktoe)***



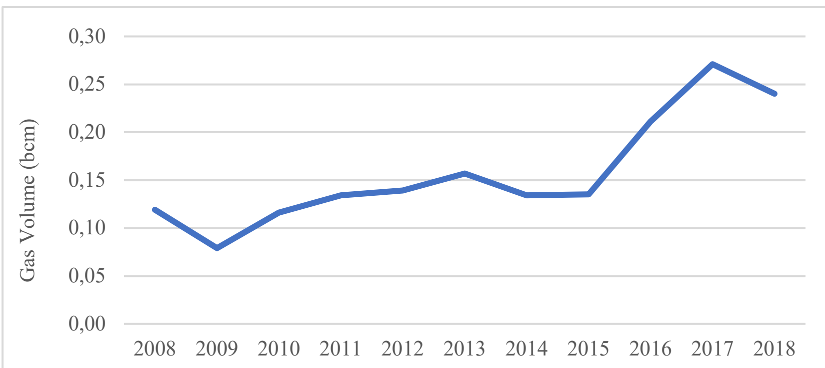

***Sources: Eurostat, Author's calculations***

## 3.10 North Macedonia

North Macedonia does not produce any natural gas. The only licensed gas transmission system operator in North Macedonia is GAMA. The natural gas transmission system in the Republic of North Macedonia is part of the Russian transit natural gas pipeline which passes through Ukraine, Romania and Bulgaria, and is intended for Turkey, Greece, Serbia and Montenegro. The connection point of the system with the Bulgarian one is on the eastern border.

During the last two years, another 200 km of network were built on top of the existing 98 km. The network's physical capacity is to transport up to 0.8 bcm per year (Energy Community, 2019, ERC, 2019). The imports from Russia were at 0.12 bcm in 2008 and have doubled since then reaching 0.25bcm in 2017.

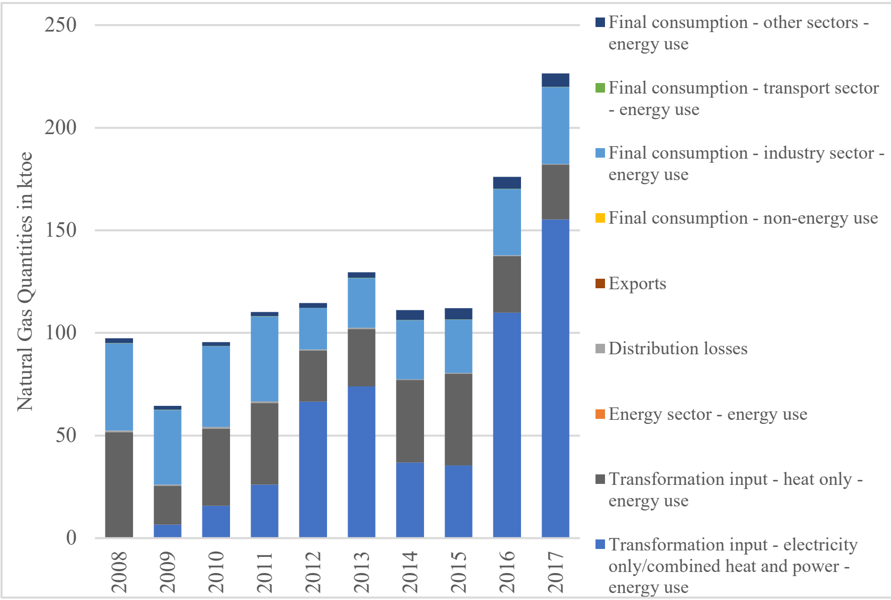
***Figure 49. Imported Natural Gas in North Macedonia from Russia***




***Sources: Eurostat, Author's calculations***

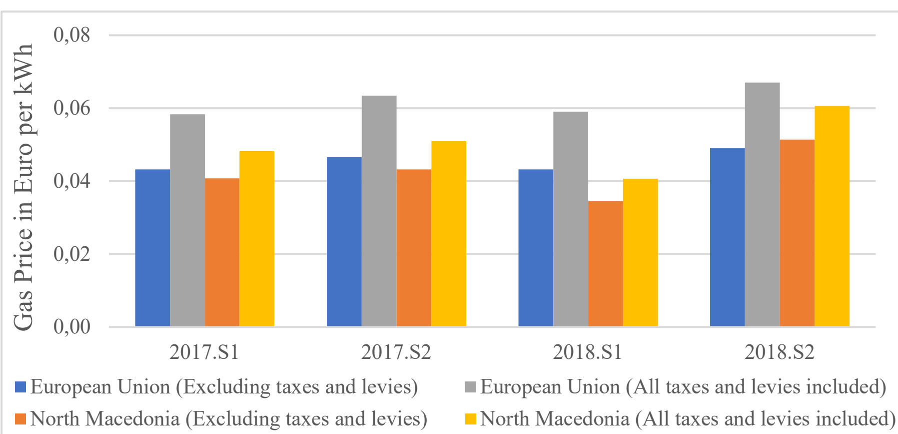
In 2008 half of the gas was consumed for district heating purposes and the other half was used by the industry, predominantly the iron and steel industry with 35% of the total consumed gas volume. Since then there have been serious changes in the consumption of gas. In 2017 the percentage of the consumption for the cogeneration of heat and power was 68% of the total consumption, the consumption only for heat was 12%, the industrial sector 17% and the commercial and public services subsector accounted for the final 3%.

*Figure 50. Natural Gas Quantities used in North Macedonia by Sectorial End-Use (in ktoe)*



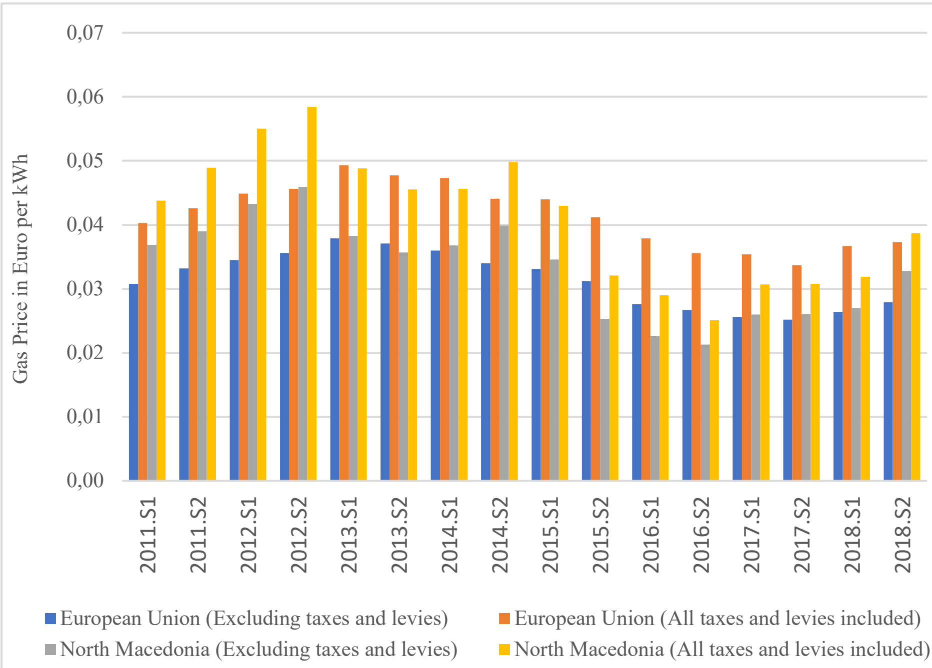

***Sources: Eurostat, Author's calculations***

*Figure 51. Evolution of Gas Prices in EU-North Macedonia for Household Consumers, Band D2 (Euro per kWh)*




***Sources: Eurostat, Author's calculations***

*Figure 52. Evolution of Gas Prices in EU-North Macedonia for Non-Household Consumers, Band I3 (Euro/kWh)*




***Sources: Eurostat, Author's calculations***

The prices for the household consumers are close to the average EU price, but always lower than that, and the tax component is 15%. For the non-household consumers, the prices were higher than the EU average until 2015. Then the final price was significantly lower than the EU average until the last semester of 2018 that the price was increased again over the EU average. The tax component for the non-household consumers is ranging from 16% in 2011 to its peak in the first semester of 2016 with 22%, before it falls again at 19% in 2018.

## 3.11 Market Comparisons among the countries in the region

The European Union has a stable energy import dependency on the total energy with around 55%, while its dependency on natural gas imports has risen from 60% in 2008 to almost 75% in 2017. Its dependency in oil imports is in the range of 85-90% during this period. As far as the Euro Area is concerned all the factors are higher than those of the EU. The total available energy import dependency is at the range of 60-65%, the natural gas has risen from 73% to 83% in 2017 and the oil imports dependency is ranging above

95%. The detailed energy import dependency indicators per country are illustrated in the following Table.

***Table 1. Energy Import Dependency by Country and Fuel (%)***

| REGION | Fuel/Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| European Union (28 countries) | Total Gross Available Energy | 54,6 | 53,7 | 52,7 | 54,2 | 53,7 | 53,3 | 53,6 | 53,9 | 53,8 | 55,1 |
| | Natural gas | 61,7 | 63,6 | 62,5 | 67,2 | 65,8 | 65,4 | 67,5 | 69,0 | 70,4 | 74,3 |
| | Oil and petroleum products | 84,7 | 84,0 | 84,7 | 85,7 | 87,1 | 87,9 | 87,8 | 89,2 | 87,1 | 86,7 |
| Euro area (19 countries) | Total Gross Available Energy | 64,7 | 63,4 | 62,0 | 62,6 | 61,3 | 60,1 | 60,3 | 62,2 | 62,0 | 63,1 |
| | Natural gas | 73,0 | 74,0 | 70,7 | 74,6 | 71,8 | 70,2 | 74,6 | 78,3 | 78,4 | 83,1 |
| | Oil and petroleum products | 97,6 | 96,9 | 96,9 | 96,3 | 96,7 | 96,9 | 96,3 | 98,5 | 96,7 | 96,1 |
| Bulgaria | Total Gross Available Energy | 52,1 | 45,5 | 40,2 | 36,9 | 36,9 | 38,5 | 35,3 | 36,5 | 38,6 | 39,5 |
| | Natural gas | 96,2 | 98,6 | 92,6 | 86,1 | 83,3 | 92,8 | 94,1 | 97,0 | 96,5 | 97,6 |
| | Oil and petroleum products | 99,6 | 101,9 | 101,9 | 98,6 | 97,9 | 104,6 | 98,7 | 101,8 | 100,5 | 101,5 |
| Greece | Total Gross Available Energy | 72,9 | 67,3 | 68,6 | 64,7 | 65,8 | 61,7 | 65,4 | 71,0 | 72,9 | 71,1 |
| | Natural gas | 100,0 | 99,7 | 99,9 | 100,0 | 100,3 | 100,0 | 99,3 | 99,9 | 99,2 | 100,5 |
| | Oil and petroleum products | 101,3 | 96,7 | 98,6 | 93,8 | 101,4 | 94,6 | 99,9 | 105,5 | 99,6 | 98,0 |
| Croatia | Total Gross Available Energy | 54,8 | 46,1 | 46,8 | 49,7 | 49,9 | 47,5 | 44,3 | 48,9 | 48,5 | 53,3 |
| | Natural gas | 16,6 | 8,1 | 18,1 | 19,5 | 37,0 | 31,8 | 28,6 | 27,1 | 33,5 | 53,8 |
| | Oil and petroleum products | 84,2 | 77,8 | 80,6 | 81,2 | 75,2 | 78,8 | 75,8 | 81,4 | 79,0 | 77,1 |
| Hungary | Total Gross Available Energy | 62,6 | 57,6 | 56,9 | 50,3 | 50,1 | 50,1 | 59,8 | 53,9 | 55,8 | 62,6 |
| | Natural gas | 88,1 | 85,6 | 78,7 | 65,6 | 72,3 | 72,1 | 97,7 | 69,7 | 78,9 | 96,3 |
| | Oil and petroleum products | 81,6 | 78,6 | 85,3 | 83,1 | 82,0 | 85,3 | 88,3 | 93,7 | 89,7 | 86,6 |
| Romania | Total Gross Available Energy | 27,4 | 19,7 | 21,2 | 21,0 | 22,3 | 18,1 | 16,4 | 16,4 | 21,6 | 23,1 |
| | Natural gas | 29,0 | 15,1 | 16,8 | 22,2 | 21,3 | 11,8 | 5,0 | 1,8 | 13,0 | 9,7 |
| | Oil and petroleum products | 51,3 | 51,2 | 51,8 | 46,6 | 51,4 | 46,8 | 54,0 | 53,4 | 56,5 | 60,6 |
| North Macedonia | Total Gross Available Energy | 46,3 | 45,2 | 44,0 | 45,6 | 48,2 | 46,7 | 51,6 | 52,5 | 59,0 | 56,1 |
| | Natural gas | 100,0 | 99,9 | 100,1 | 100,0 | 100,0 | 100,1 | 99,9 | 100,0 | 100,0 | 100,1 |
| | Oil and petroleum products | 97,5 | 106,4 | 97,8 | 97,3 | 103,7 | 93,9 | 99,9 | 99,8 | 101,9 | 99,4 |
| Albania | Total Gross Available Energy | 49,8 | 46,4 | 28,9 | 35,7 | 15,6 | 25,3 | 28,7 | 12,6 | 20,2 | 38,3 |
| | Natural gas | 0,0 | 0,0 | 0,0 | 0,0 | 0,0 | 0,0 | 0,0 | 0,0 | 0,0 | 0,0 |
| | Oil and petroleum products | 62,8 | 61,7 | 47,6 | 30,9 | 2,0 | 26,1 | 23,1 | 6,4 | 26,4 | 40,3 |
| Serbia | Total Gross Available Energy | 37,7 | 32,3 | 33,5 | 30,4 | 27,9 | 24,1 | 27,9 | 27,7 | 29,7 | 33,8 |
| | Natural gas | 89,3 | 90,4 | 84,5 | 73,1 | 84,9 | 80,5 | 69,0 | 79,2 | 75,6 | 82,1 |
| | Oil and petroleum products | 86,8 | 80,4 | 74,8 | 72,6 | 65,4 | 60,7 | 61,7 | 64,1 | 72,5 | 75,4 |
| Turkey | Total Gross Available Energy | 72,4 | 70,4 | 70,6 | 71,1 | 75,6 | 75,4 | 76,3 | 77,9 | 75,5 | 77,2 |
| | Natural gas | 100,2 | 100,1 | 98,1 | 96,6 | 100,1 | 97,8 | 99,6 | 99,9 | 98,3 | 101,7 |
| | Oil and petroleum products | 93,4 | 91,0 | 92,6 | 91,4 | 95,6 | 93,1 | 93,1 | 97,6 | 95,5 | 95,7 |
| Ukraine | Total Gross Available Energy | 42,4 | 36,1 | 31,6 | 37,7 | 31,4 | 27,3 | 26,2 | 32,5 | 29,5 | 37,1 |
| | Natural gas | 80,4 | 75,1 | 53,5 | 77,2 | 61,8 | 57,3 | 47,0 | 51,0 | 34,4 | 45,9 |
| | Oil and petroleum products | 69,4 | 69,9 | 72,9 | 73,6 | 69,0 | 70,8 | 69,1 | 75,0 | 84,8 | 80,8 |

***Sources: Eurostat, Author's calculations***

- Bulgaria was able to decrease its total energy dependency by 10% in the past decade, but its import dependency on natural gas and oil is still close to 100%.
- Greece on the other hand was not even able to decrease for a long period the total energy import dependency which is as high as 70%

in 2017 and is almost 100% dependent on imports of natural gas and oil.

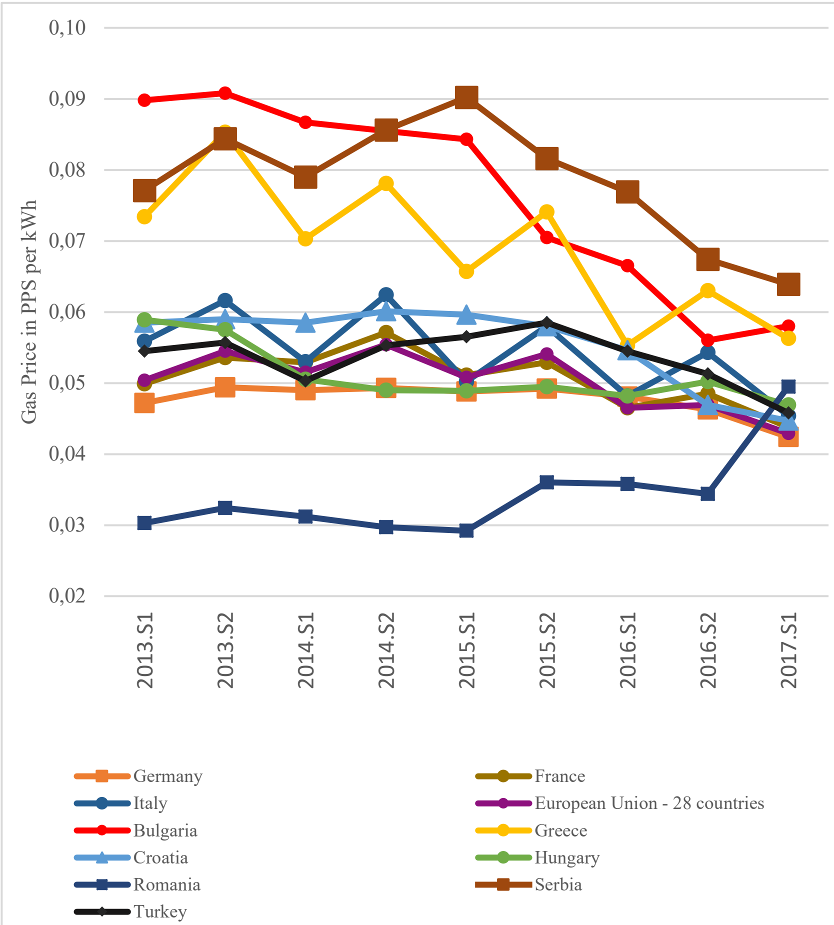
- Croatia has also not been able to withhold the decrease in the total energy import dependency, which is at 53%, but the natural gas import dependency skyrocketed from 16% in 2008 to 53% in 2017. The oil and petroleum products import dependency though, was decreased by 7% landing at 77% in 2017.
- Hungary has decreased its total energy import dependency from 63% in 2008 to 50% in 2012 and 2013 but finally in 2017 it was again 63%. Both the natural gas and oil and petroleum products import dependency have risen the past decade from 88% and 81% to 96% and 86% respectively.
- Romania is the country that has the lowest total energy import dependency of the ones under examination. The indicator is ranging from 16% to 27%, showing a country that is almost self-sustained as far as energy is concerned. The natural gas import dependency has reached as low as 1.5% in 2015 from 29% in 2008 before settling at 10% in 2017. The trend was not similar for the oil indicator which had a raise by 10% from 2008 to 2017, settling at 60%.
- North Macedonia is completely dependent on imports for natural gas and oil, but the total energy import dependency has raised just by 10% during the last decade, from 46% to 56%.
- Albania on the other hand as mentioned earlier does not import any gas at all, as a result the indicator is 0. The fluctuation in the indicators for the total energy and the oil products is high. For the total available energy import dependency, it ranges from 50% in 2008 to 12% in 2014, before jumping up to 38% in 2017. For the oil indicator the trend is similar, it started at 60% in 2008, fell to 6% in 2014 and then increased to 40% in 2017.
- Serbia is relatively independent from imports as far as the total energy is concerned, with a score decreasing from 37% in 2008 to 33% in 2017. But the natural gas and oil indicators show a high dependency on imports of these fuels, with 82% and 75% respectively in 2017.
- Turkey has a profile that is close to Greece. The total energy import dependency is at the range of 70-80% but the natural gas and oil and petroleum products indicators are above 95% in almost all the years under examination.
- Finally, Ukraine has decreased its total energy import dependency from 42% in 2008, to 27% in 2016 before increasing it again to 37% in 2018. The most notable is that the natural gas import dependency has fallen from 80% in 2008 to 46% in 2017, while the oil and petroleum products increased from 69% to 80%.

## 3.12 Comparison of price evolution in SE Europe

In order to compare the prices that the consumers are paying in the different countries, the selected currency will be the Purchase Power Standard (PPS). In the following graphs the prices that the household consumers are paying in PPS per kWh in the examined countries (Greece, Bulgaria, Romania, Hungary, Croatia, Turkey and Serbia) are compared with the prices of three major European gas market countries, Germany, France and Italy as well as the EU average price.

The **purchasing power standard**, abbreviated as **PPS**, is an artificial currency unit. As the Eurostat defines it "*Theoretically, one PPS can buy the same amount of goods and services in each country. However, price differences across borders mean that different amounts of national currency units are needed for the same goods and services depending on the country. PPS are derived by dividing any economic aggregate of a country in national currency by its respective purchasing power parities. PPS is the technical term used by Eurostat for the common currency in which national accounts aggregates are expressed when adjusted for price level differences using **purchasing power parities**, (PPPs). **PPPs** are indicators of price level differences across countries. Thus, PPPs can be interpreted as the exchange rate of the PPS against the euro. PPPs tell us how many currency units a given quantity of goods and services costs in different countries. Purchasing power parities are obtained by comparing price levels for a basket of comparable goods and services that are selected to be representative of consumption patterns in the various countries. PPPs make it possible to produce meaningful indicators (based on either price or volume) required for cross-country comparisons, truly reflecting the differences in the purchasing power of, for example, households. Monetary exchange rates cannot be used to compare the volumes of income or expenditure because they usually reflect more elements than just price differences, for example, volumes of financial transactions between currencies and expectations in the foreign exchange markets*."

*Figure 53. Evolution of Gas Price in PPS per kWh for Household Consumers, Band D2 (Excluding all Taxes and Levies)*

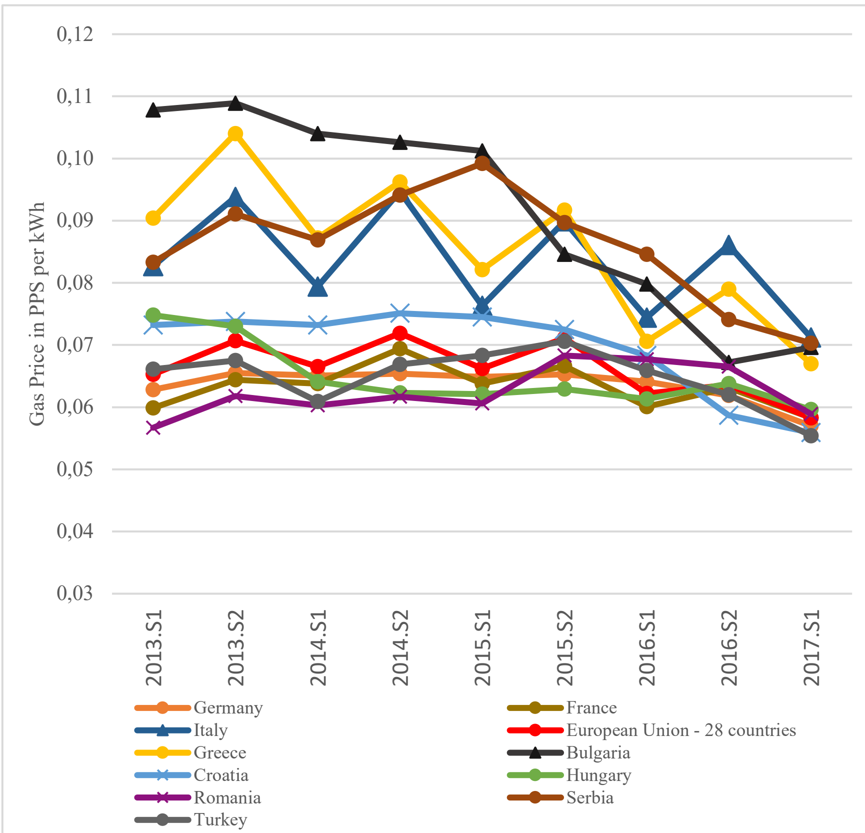



***Sources: Eurostat, Author's calculations***

It is obvious that three countries, Greece, Bulgaria and Serbia were paying significantly higher prices in the beginning of the examination period. Romania on the other hand was paying by far the lowest price for gas. The rest of the countries were paying a price that was close to the average. It is important to notice that in 4 years' time all the prices dropped with the exception of Romania, resulting in the convergence of the prices.

With the impact of taxes, we can see that the advantage that Romania had in the price without taxes is now absent. Still Greece and Bulgaria are paying higher prices, but this time Italy is joining them in the group of countries with the highest prices for the final consumer. Once again, we observe the convergence of the prices, as they all move at lower levels.

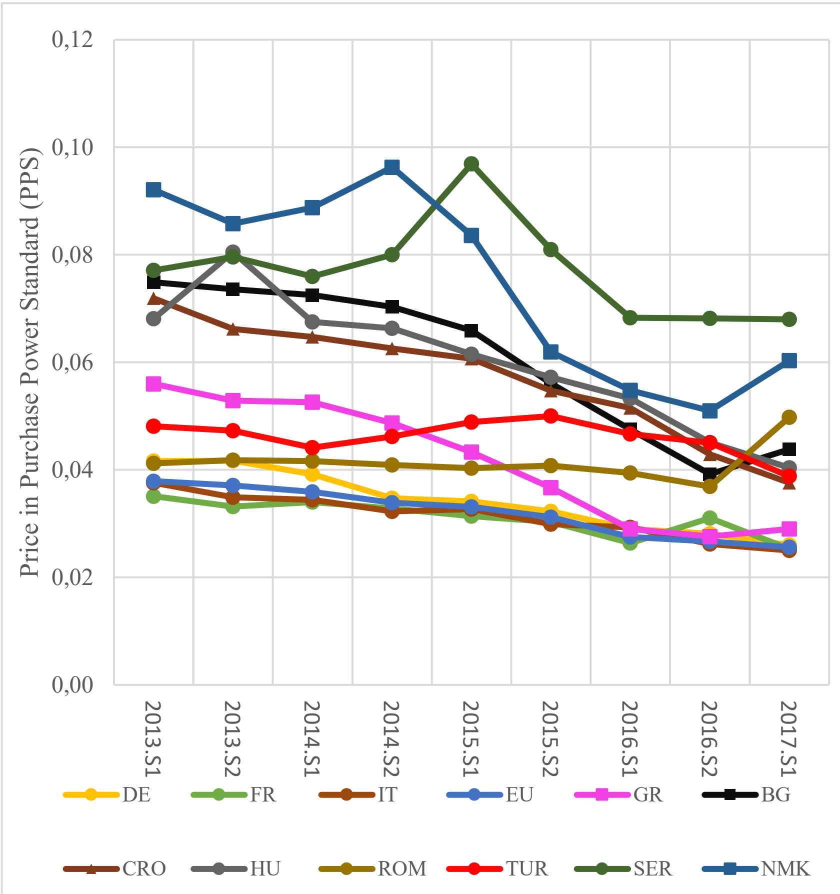
***Figure 54. Evolution of Gas Price in PPS per kWh for Household Consumers, Band D2 (Including all Taxes and Levies)***




***Sources: Eurostat, Author's calculations***

In the following graphs, the prices in PPS per kWh in Greece Bulgaria, Romania, Hungary, Croatia, Turkey, Serbia, North Macedonia, Germany, France and Italy are illustrated in comparison with the respective EU average price.

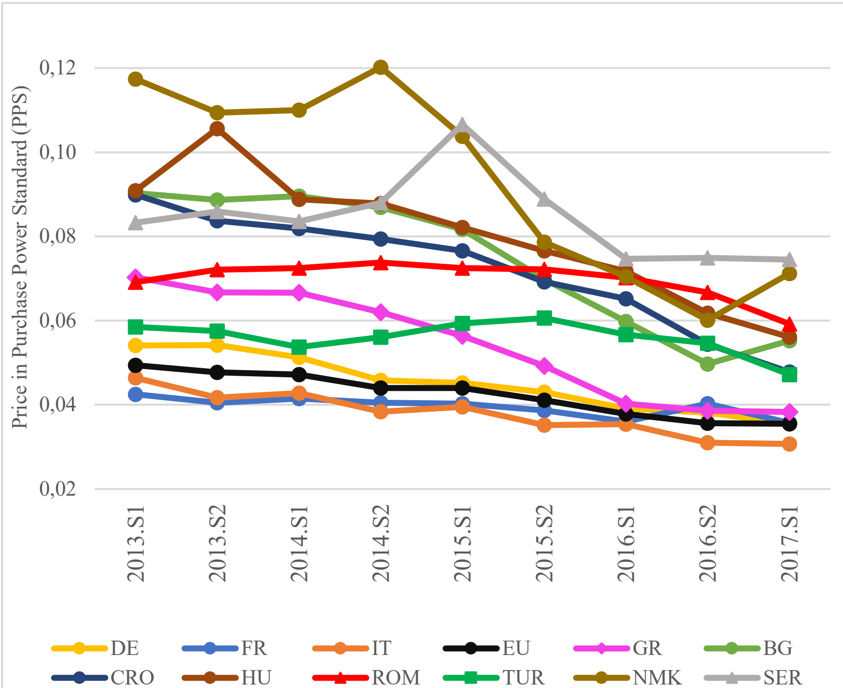
*Figure 55. Evolution of Gas Price in PPS per kWh for Non-Household Consumers, Band I3 (Excluding all Taxes and Levies)*




***Sources: Eurostat, Author's calculations***

For the non-household consumers, we can observe in 2013 that North Macedonia is paying the highest price, followed by a group of countries (Serbia, Bulgaria, Croatia and Hungary) that pay similar prices. Then Greece and Turkey follow with substantial difference from the above group and finally the three major gas markets along with Romania are closer to the EU average and are paying the lowest price. With the exception of North Macedonia and Serbia we can see that the prices are decreasing and are converging with the EU average.

*Figure 56. Evolution of Gas Price in PPS per kWh for Non-Household Consumers, Band I3 (Including all Taxes and Levies)*




***Sources: Eurostat, Author's calculations***

With the inclusion of the taxes, the highest paying country is again North Macedonia, followed by the group of Hungary, Bulgaria, Croatia and Serbia. Then Greece and Romania have almost the same prices and finally Turkey, Germany and Italy. The country with the lowest price is France.

In the first semester of 2017 the prices have dropped for all the consumers creating three different price groups. The first that has the highest price is Serbia and North Macedonia. They are followed by the group of Romania, Hungary, Bulgaria, Croatia and Turkey and the final group that offers to the non-household consumers the lowest gas price is Greece, Germany, France, Italy and the EU average.

## 3.13 Geopolitical implications in the region

Energy and resources have always been a keen reason for implications in the diplomatic relations among countries, neighbouring and non-neighbouring. That is the case also for the region of Southeast Europe. In a region that more than 15 independent countries coexist, in the crossroad of Europe, Asia and

Africa, major diplomatic powers as the European Union, the United States and Russia are trying to reinforce their position, using energy and especially gas as a lever to accomplish that.

As far as the European Union is concerned, it is clear by the previous analysis that is making a huge effort to secure the energy needs of its member countries with all the proposed interconnections and the diversification of the energy suppliers. The two new proposed LNG import terminals are creating the chance for entrance of new gas suppliers from all over the world and especially a new market for the US LNG, strengthening the EU-US trade bonds. The TANAP-TAP project is making Azerbaijan an important gas supplier for the EU. The European Union is trying to allure the Balkan countries that are not yet its member states, like Albania and North Macedonia, by presenting itself as a reliable alliance that looks after the interests of its members.

On the other hand, Russia is trying to keep its dominance is the region especially with its close partnership with Serbia through the upgrade of the use of gas and the new infrastructure projects that will be financed by Russian companies in the country. Also, the fact that the European part of the TurkStream will pass by Bulgaria, Serbia and Hungary makes evident that Russia is not willing to let the well-established relationship with these countries to be damaged by the turmoil in the Russo-Ukrainian trade relations. Russia historically considers the Balkan region as a region that is or should be under its diplomatic dominance, thoughts that perhaps can be explained by its influence during the Soviet Union era or the common religion that Russian people share with the majority of the Balkan population.

The US are depending a lot of their diplomacy in the economic affairs. The creation of a new market for their LNG, by the completion of new LNG import terminals, can signify their potential to increase their power in an area that thirty years ago only Greece and Turkey were members of the North Atlantic Treaty Organisation.

Greece is trying to play its role as the main import gate of the alternative routes of supply of gas from the South to the North and from the East to the West with the development of the LNG infrastructure and the interconnections. As far as the gas from the South East Mediterranean basin is concerned, and especially that of Cyprus, its major role is yet to be proved, with the tensions between the neighbouring countries, especially Cyprus and Greece with Turkey, adding extra difficulties in its extraction. The interconnection with the Bulgarian system and the LNG terminal of Alexandroupolis will provide extra flexibility to the Balkan system as a whole.

The implementation of the TANAP-TAP project was evidence that Turkey and Greece can find a way through economy to overcome their diplomatic tensions. Turkey will also use its gas infrastructure to upgrade its position in the diplomatic sphere. Turkey’s role as a transit country is upgraded by the

TANAP-TAP project but also by the TurkStream project that aspires to make the use of the Transbalkan pipeline obsolete.

Bulgaria aspires to play a central role in the Balkans due to its geographical position and its participation in a number of projects. The Bulgarian companies are involved in Turkstream, the interconnection with Greece, Romania and Serbia and have expressed their interest in participating in the Alexandroupolis LNG terminal. It is clear that they are trying to develop a gas hub in Bulgaria by achieving trade agreements with everyone including the EU and its member states, the US and finally Russia.

The major implications are identified at the gas transit agreement between Russia and Ukraine. Throughout the last years Russia has developed a number of projects like NordStream II and Turkstream in order to bypass the Ukrainian pipeline system. These projects however are not yet completed. Their aim is to sign a short-term transit agreement with Naftogaz.

On the other hand, the Ukrainian counterparty wishes to sign a long-term agreement that will provide them with a significant amount of money as revenues. The EU is the third partner involved in the case, trying to play the role of the middleman to secure the gas supply in its territory and to avoid similar results with last Russian-Ukrainian crises. Both the Russians and the Ukrainians are positive that they will be able to provide the EU with the needed gas volume even without the accomplishment of an agreement playing a tough diplomatic game. The EU on its side is being prepared by filling up its storage facilities and bringing them at full storage capacity as early as the end of September. The proposed infrastructure of the LNG facilities and the interconnections among the Balkan countries can lead to a gas corridor that will bring regasified gas from Greece or gas from Azerbaijan, through Turkey, all the way to the Ukrainian storage facilities, since Ukraine holds the largest storage capacity in the region. This could happen with the reversion of the flow of the Transbalkan pipeline.

## Chapter 4

# Outlook for Gas Production in Azerbaijan and future supplies: prospects to 2040

# 4. Outlook for Gas Production in Azerbaijan and Future Supplies: Prospects to 2040

by Gulmira Rzayeva[8]

## 4.1 Introduction

This chapter of the book will focus on the outlook for Azerbaijan's natural gas production between now and 2040 to identify the country's capability to fill the pipelines along the Southern Gas Corridor project. The aim is to identify the potential quantities of gas that SOCAR may have available, in the next few years (to 2020), by 2025, and in a longer-term perspective.

To achieve this, it is necessary to look at existing fields for which PSAs are already in place and that are at different stages of exploration, appraisal, and development, as well as analyzing structures that have been discovered and where there is a firm intention to develop the block, but where no wells have yet been drilled and no data is yet available (with the exception of seismic data).

The existing fields and structures in the country comprise two groups of reserves and resources: (i) Fields and structures that are in the international consortia's production portfolios, as well as (ii) structures/blocks that are expected to be released under a PSA with an IOC/IOCs. This group of reserves and resources comprises both (i) contracted gas and (ii) un-contracted gas, so-called 'free gas' that will show a growing surplus, potentially available for new exports.

The second group of fields includes all the reserves that are included in the SOCAR/Azneft production unit gas production portfolio, which mainly supply the domestic market, with the excess of gas exported by SOCAR to Georgia and Turkey. The security of gas supply to the domestic market largely depends on the future development of these fields and the amount of gas that SOCAR will receive and/or produce.

Azerbaijan's gas balance in 2018 is shown in Table 1. In 2018 SOCAR imported 1.8 bcm of gas (State Statistical Committee), (1 bcm from Russia and 0.8 bcm from Iran), and exported 2.5 bcm to Georgia. It received, free of charge, 2.3 bcm from ACG associated gas and 3.2 bcm as its share from SD (SOCAR). SOCAR's own gas production was 6 bcm, with gas losses of around 600 mcm. The total gas volume that was available to SOCAR for the

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domestic market, excluding volumes for export and losses, was 13.9 bcm of which, SOCAR stored 2.3 bcm from storage, having 1.1 bcm of surplus.

***Table 2. Azerbaijan Gas Balance 2018***

| Activity | BCM |
|---|---|
| Gross gas production | 30.6 |
| Including Petroleum gas from ACG | 12.5 |
| ACG re-injected gas | 10.2 |
| Including SD gas production | 11.5 |
| SOCAR gas production | 6.5 |
| Commercial gas production | 19.2 |
| Including Petroleum gas from ACG delivered for Azerbaijan for free | 2.3 |
| Imported | 1.8 |
| Exported | 9.9 |
| Including export to Turkey | 7.2 |
| Including export to Georgia | 2.5 |
| Losses | 0.6 |
| Storage withdrawal | 2.3 |
| Total | 11.1 |
| Consumption | 11.1 |
| Gas stored | 2.3 |

***Source: State Statistical Committee of the Republic of Azerbaijan (SSCRA)***

*Table 3. SOCAR Gas Balance 2018*

| Activity | BCM |
|---|---|
| Imported | 1.8 |
| Exported to Georgia | 1.4 |
| Net gas delivery by ACG | 2.3 |
| Gas purchase from SD1 | 3.2 |
| SOCAR gas production | 6.5 |
| Petroleum gas from ACG delivered for Azerbaijan free | 2.3 |
| Storage withdrawal | 0 |
| Losses | 0.6 |
| **Total** | **11.1** |
| Consumption | 10.5 |
| Gas stored | 2.3 |

***Source: SSCRA***

*Table 4. Azerbaijan Gas Balance 2019 (estimation)*

| Activity | BCM |
|---|---|
| **Gross gas production** | **36.4** |
| Including petroleum gas form ACG | 13.2 |
| SD gas production | |
| SOCAR (Azneft) | 14 |
| **Commercial gas production** | 7.6 |
| Import | **24.7** |
| | 1.3 |
| Export | 12 |
| Petroleum gas from ACG delivered to AZE for free | 2.7 |
| SD1 | 3.2 |
| SOCAR production | 6.1 |
| Storage withdrawal | 0 |
| Losses | 0.5 |
| **Total** | **13.5** |
| Domestic gas consumption | 12.9 |
| Gas stored | 0.6 |

***Source: SSCRA***

## 4.2 Outlook for Azerbaijan gas production: Producing fields under PSA

This group of reserves includes the fields that have been producing natural gas and condensate (except Absheron phase 1, which is scheduled to be brought online late 2019) for both export and the domestic market. Almost half of the gas for the internal market comes from the fields of this group under the PSA agreements (Tables 8, 9, 10). The aim of this section is to identify the potential volumes of gas that SOCAR will receive from these fields in the short-, mid-, and long-run.

***Shah Deniz Phases 1 & 2***

Azerbaijan's earliest discovered gas reserves are largely concentrated in the Absheron-Pribalkhan Trough and the South Caspian Deepwater Basin. The South Caspian Deepwater Basin is at an early stage of exploration and development, but nevertheless currently contains around 75% of Azerbaijan's known remaining commercial gas reserves. The *Shah Deniz* discovery, in the South Caspian Deepwater Basin, is Azerbaijan's most important gas field with commercial gas reserves of 1.2 tcm, and some of this has been already contracted. The current output comprises almost 9 bcm/year of gas contracted for Phase 1 and slightly more than 16 bcm/year contracted for Phase 2. The SD consortium holds three supply contracts with buyers in three countries to provide gas from the first stage of the field: Turkey, Georgia (transit contract only), and Azerbaijan. The gas supply contract to Turkey for the volume of 6.6 bcm/year will expire in 2021. The transit contract with Georgia is signed for 60 years.

According to the PSA signed between the IOCs and SOCAR, SOCAR’s SD1 share of gas is 1.5 bcm/year. However, in 2018 SOCAR purchased 2.2 bcm from Phase 1 for the domestic market and received no quantities from Phase 2 as all the volumes were exported starting August 2018.

Given the fact that the *SD1 field* started producing in late 2006 and reached its plateau level in 2010, the field’s geological tail-off period should begin in 2024–2026. During the tail-off period, production levels may decrease by around 2 bcm/year or more, depending on well productivity. This leads us to assume that there might not be sufficient gas to extend the long-term contract with the Turkish BOTAŞ, which expires in 2021, to provide 6.6 bcm/year on an LTC basis. Any remaining volume from the tail-off period may either be purchased by SOCAR for the domestic market and/or export; or a short-term contract might be signed with reduced volume of gas for export from Phase 1. Another scenario is that the remaining volume from SD1 could be added on top of the contracted 6 bcm/year of SD2 gas. Realization of this scenario will strongly depend on whether both seller and buyer would be interested financially and legally in the exchange of SD1 volumes under the SD2 contract. In the event that the contract with BOTAŞ is not extended and SOCAR receives the remaining volume from SD1, SOCAR may have from 3 to 5 bcm/year of additional gas, with a gradual decrease year-by-year from 2025 on.

### ***ACG associated gas***

At the time that the Azeri-Chirag-Deepwater Gunashli PSA was negotiated (prior to that of Shah Deniz), the IOCs were primarily concerned with oil. With uncertainties over both the quantity of associated gas production over the term of the PSA, and the market for natural gas in Azerbaijan and neighbouring Caucasus markets, it seemed appropriate to agree to pass any gas production, not required for operations, to SOCAR, which had been supplying the Azerbaijani market for many years (Rzayeva, 2015). The future volumes of gas production from the ACG field depend on the requirement to re-inject gas into the reservoir to maintain pressure and hence maximise oil recovery and maintain production rates. Through time it is likely that the gas injection requirement will increase, and hence the volume of associated gas transferred to SOCAR from ACG and Shallow Water Guneshli may gradually decrease. Since 2007, gas production at the Guneshli (shallow water) field has increased steadily. This is mainly due to extensive exploration and further drilling by SOCAR, as well as improvements in the collection of associated gas and a reduction of volumes being flared and vented.

*Table 5. ACG Associated Gas Transferred to SOCAR*

| Year | Volume, BCM |
|---|---|
| 2009 | 4.0 |
| 2010 | 3.4 |
| 2011 | 3.3 |
| 2012 | 3.4 |
| 2013 | 2.2 |
| 2014 | 2.8 |
| 2015 | 3.2 |
| 2016 | 2.8 |
| 2017 | 2.9 |
| 2018 | 2.3 |
| 2019 (e) | 2.7 |
| 2020 (e) | 2.6 |
| 2021 (e) | 2 |
| 2022 (e) | 2 |
| 2023 (e) | 1.6 |
| 2024 (e) | 1.4 |
| 2025 (e) | 0.6 |
| 2026 (e) | 0.9 |
| 2027 (e) | 0.8 |
| 2028 (e) | 0.9 |
| 2029 (e) | 0.6 |
| 2030 (e) | 0.5 |

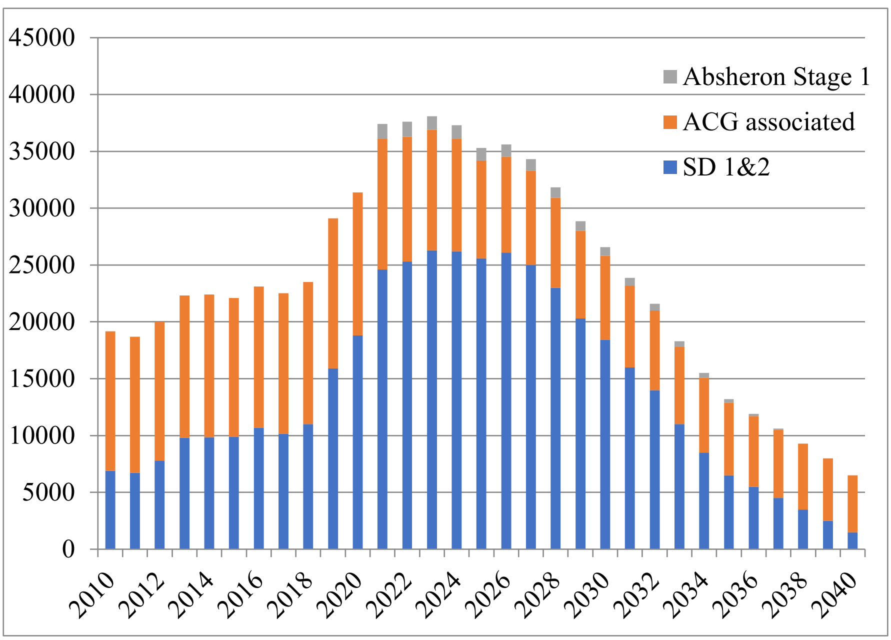
***Sources: State Statistical Committee, Author's estimates***

Over the last three years, SOCAR has increased the volume of gas it receives from ACG; in 2017 it was 2.9 bcm (Tables 9 & 11). It is expected that in the following years the gas volumes that will be transferred to SOCAR will be at least halved in comparison with the previous three years (Table 11) as more associated gas will be needed for reinjection to maintain the oil production level steady. The possible replacement of about 1-2 bcm/year of gas may come from Bulla Deniz and associated gas from Oil Rocks and Umid if SOCAR manages to increase Bulla Deniz production from the current 455 mcm/year to around 850 mcm in 2018 and 1.2 bcm in 2019, and Oil Rocks production from 57 mcm in 2017 to 81 mcm in 2018, as planned. Also, SOCAR was planning to increase the production at the Umid field from 311 mcm in 2017 to 510 mcm in 2018 and 1267 mcm in 2019 once joint production with an IOC starts. As there was no contract signed with any IOC till October 2019, it seems that the production increased will be shift to the following years.

***Absheron phase 1***

The Absheron field is currently under development through a joint venture of Total and SOCAR based on equal interest. It is planned that production of 1.3 bcm/year will start from early 2021 and will be sold to SOCAR for the domestic market.

***Figure 57. The Gas Production Projection of the Fields Producing Under PSA, mcm (2010-2040)***




***Source: SOCAR***

## 4.3 Probable reserves: Absheron phase 2, Babek, SD phase 3, ACG NAG, Shafag/Asiman and Garabagh

This group of reserves is in fields and structures that are discovered, some preliminary data is available, no well has been drilled, or one or two wells have been drilled and no further exploration work has been carried out. Consequently, it is un-contracted gas, so called "free gas" that will show a growing surplus, potentially available for domestic demand and/or new exports. These are the Absheron phase 2, the Babek structure, ACG non-associated gas (NAG) and the Shafag-Asiman and Garabagh structures. These fields and structures have all the potential to be explored, appraised and developed in mid-run as the consortia/joint ventures are in place, PSAs or an agreement for future PSAs have been signed, except for the Babek structure, and there is a firm intention of the partners and SOCAR to develop the fields in the mid-term perspective.

***Absheron Phase 2***

Phase 2 is planned to be explored and developed after Phase 1 comes on-stream. It is planned that the final investment decision regarding Phase 2 will be taken by the mid-2020s depending on marketing arrangements, the price in internal and external markets, and availability of markets. The annual plateau level of production from Phase 2 may add 5 bcm/year on top of the 1.3 bcm/year from Phase 1. Some part of these volumes may be kept for the domestic market in case of necessity and the excess of gas could be exported to the Turkish and/or the European market, depending on the availability of market share, reasonable prices, and other marketing considerations.

***The Babek structure***

This structure can add substantial volume to gas production once the Service Risk Agreement is signed with an IOC and production from the field is brought online. The estimated gas reserves of this structure are 400 bcm and it is expected that the production at plateau level might possibly reach 8 bcm/year. The commencement of production from this structure is planned from 2022 with 138 mcm, with gradual increase year-on-year to 547 mcm/year at plateau level and decline starting in 2027.

***The Shah Deniz Phase 3***

Phase 3 is a deeper layer of gas production and thus geologically complex to develop. For that, an additional drilling rig is needed. According to BP, SOCAR wants to start exploration of Phase 3 as soon as possible once a rig is available. However, BP's position is that before the gas is delivered to the European market, it will not become involved in a new venture in Azerbaijan due to workload and staff cuts. Therefore, it is expected that SD3 exploration will start after 2020, when gas from Phase 2 will reach the European market.

At this stage, it is not known what the terms and conditions of the marketing arrangement will be, and consequently the possible volume SOCAR may get for the domestic market is unknown. According to BP, gas production from phase 3 may be 10 bcm/year.

***ACG NAG***

There is no information available on any plans regarding the non-associated gas from the deeper layer of the ACG field. The discussion on a possible new agreement on gas production has not started yet, after the ACG PSA was extended for 25 years (2049). However, this field is one of the potential contenders to be developed in the mid- to long-run given the fact that the consortium exists, and the partners have an intention to develop gas production. The decision will largely depend on the commerciality of the project and availability of a market both internal and external.

***The Garabagh block***

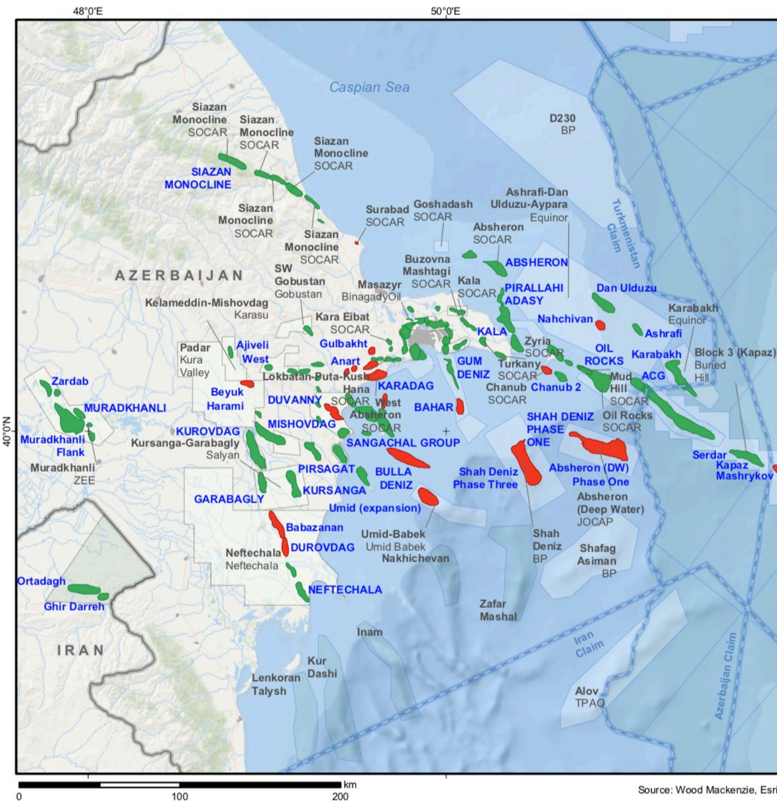
This oil and gas block is located 130 km east of Baku, in the northern part of the Absheron archipelago (Figure 58) with a target potential reservoir strata depth of 3,300–4,200 metres. According to preliminary estimates the block may be the second major contract for oil field development in the Caspian Sea after the ACG project, with initial oil reserves of 100 million tonnes and probable 40 bcm of natural gas. The possible annual gas production at plateau level may be up to 2 bcm starting from 2021.

In December 2017, SOCAR and Statoil signed two contracts on the main principles of cooperation. The first contract covers issues of exploration, development and main commercial principles and provisions of the PSA (production sharing agreement) on some promising structures in the Azerbaijani sector of the Caspian Sea, while the second contract covers main commercial principles and provisions of the Risk Service Contract (RSC) regarding the Garabagh field. SOCAR together with Statoil plans to start gas production from 2021 with 32 mcm as a ramp up volume and increase production to 2.1 bcm in 2025 at plateau level. From 2026 production from this field will face its natural decline.

***The Shafag and Asiman structures***

These structures are located 125 km to the southeast of Baku (Figure 58). The contract area covers 1,000 km$^2$, at a water depth of 650-800m with a reservoir depth of 7,000 metres. The Shafag and Asiman structures have been previously called D8 and D10, respectively.

*Figure 58. Map of Offshore Oil and Gas Fields/Blocks in Azerbaijan*




***Sources: Wood Mackenzie, Esri***

The MOU between SOCAR and BP covering this area was signed in July 2009 and the PSA on joint exploration and development for a period of 30 years (with potential extension of up to 5 more years) in October 2010. It was agreed that the exploration period will be 4 years with possible prolongation for another 3 years. The first stage of exploration works envisions the drilling of two wells. The second stage assumes drilling of two more wells, if necessary. If and when the participants move to the production stage, they have agreed to operate the project jointly. The two companies hold equal interests in the project.

With a size of 1,100 square km, this is the third largest concession to be awarded to date in Azerbaijan. This block has never been explored, but initial estimates put the probable reserves at between 350 and 500 bcm of natural gas and 65 million tonnes of condensate. The potential annual gas production is estimated to be 4-6 bcm. The 2-D and 3-D seismic study was carried out by Caspian Geophysical under the BP contract in 2011 and 2012. The third data interpretation phase was completed in the first half of 2014.To date, no exploration wells have been drilled, and it is expected that the exploration and appraisal stage could take from 3 to 4 years. According to BP, the company has already expressed its interest in further exploring the block. However, this will happen no sooner than 2020, when gas from SD2 is scheduled to start flowing to the European market.

Moreover, the availability of a drilling rig is a crucial factor to start drilling works. Given the current development status of the block and the firm intention of BP to develop the field, we can assume that the first gas could come on stream no earlier than the late 2020s. This field has all the possibilities to be developed in the next 5 to 10 years, given BP intentions.

## 4.4 SOCAR/Azneft gas production

The SOCAR/Azneft gas production portfolio comprises volumes from mature natural gas fields that have been producing for decades, but which are now in decline (Gum Deniz-Bahar, Bahar 2, Bulla Deniz, Harazire-Duvanni, Oil Rocks, Guneshli, etc.). Gum Deniz-Bahar, Bahar 2, and Umid are fields that are managed by SOCAR separately or under PSA (Bahar). All the gas produced is consumed in the domestic market. There are several oil fields with substantial associated gas reserves, such as Azeri-Chirag-Guneshli and Shallow Water Guneshli. Significant quantities of associated gas are present in other offshore reserves such as Oil Rocks, although much of this gas is used in field operations or re-injected to enhance oil recovery. According to the reservoir engineering and reserves analyst company Miller & Lents, as of January 2015 SOCAR's proven gas reserves were 61.15 bcm, deriving mainly from the above-mentioned fields (excluding SOCAR's share of Shah Deniz gas). The lion's share of SOCAR gas comes from the Guneshli, Oil Rocks, Bulla Deniz, Sangachal-Deniz-Duvanli-Deniz-Harazire, and Palchiq-Pipillesi fields that are developed by SOCAR gas production unit "Azneft" (in total approximately 5 bcm in 2017) (Table 6).

As shown in Table 6, SOCAR managed to significantly increase gas production in the Bulla-Deniz field in 2014 at the expense of more wells drilled, but was, however, unable to maintain production at the same level due to shortage of investment. As a result, the production loss in this field was more than 200 mcm in 2015, although this subsequently decreased to a loss of around 100 mcm/year and has now recovered to a level approximately 70 mcm/year below the 2014 level.

***Table 6. Azneft Gas Production (2010 - 2017)***

| Fields | Gas Production by Azneft, mln $m^3$ | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| Oil Rocks | Associated | 55.2 | 56.8 | 56.7 | 56.7 | 56.7 | 56.7 | 57.4 | 57 |
| Palchiq Pipillesi | Associated | 9.8 | 9.8 | 9.8 | 9.8 | 9.8 | 9.8 | 9.1 | 9 |
| Sangachal-Duvannı-Xara-Zira island | Associated | 56.8 | 58.2 | 53.7 | 65.4 | 62.6 | 60.2 | 66.8 | 106 |
| | Natural gas | 143 | 112.8 | 95.2 | 97.7 | 65.2 | 66.1 | 60.4 | 57.8 |
| Bulla-Deniz | Associated | 24.8 | 23.3 | 20.6 | 23.5 | 22.5 | 18.5 | 14.6 | 25.8 |
| | Natural gas | 104.6 | 76.8 | 73.8 | 317 | 506.1 | 297.4 | 394.2 | 428.3 |
| Guneshli | Associated | 1325.1 | 1081.7 | 1072 | 1065 | 1082 | 1116 | 1167.6 | 1143 |
| | Natural gas | 4906.6 | 5161.1 | 4950 | 4732.7 | 4326 | 4253 | 3591.7 | 3230 |
| **Total** | | **6626** | **6582.5** | **6331.8** | **6367.8** | **6131** | **5878** | **5361.8** | **5057** |

***Source: SOCAR***

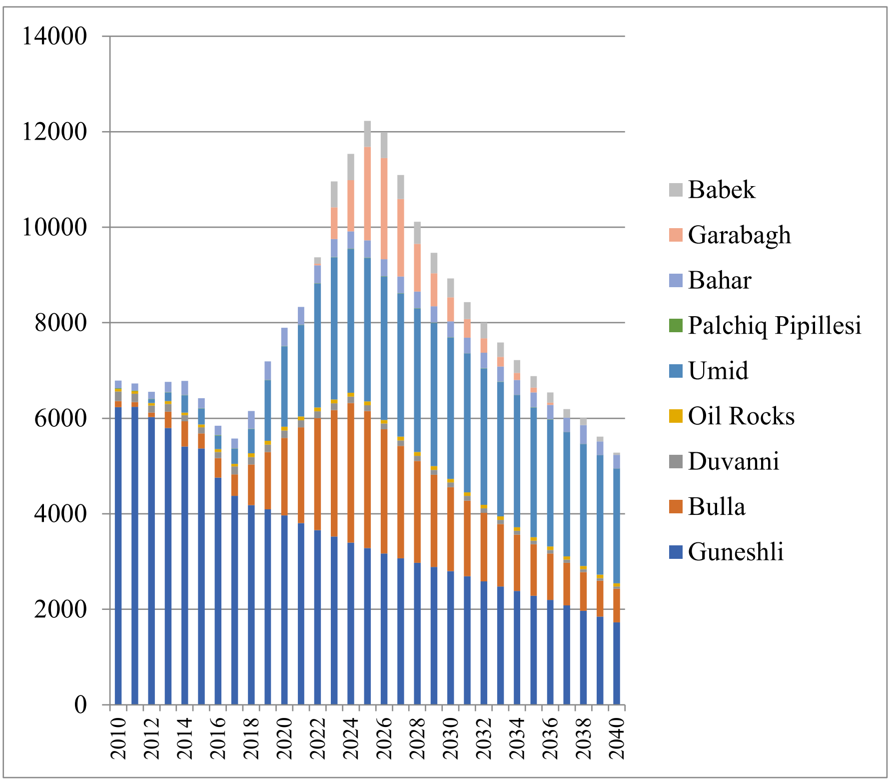
With SOCAR's own natural gas production declining, the company has launched a strategy of investing to increase recovery and production from these fields. Despite this, given the maturity of its existing fields, SOCAR will be looking more production from within the joint ventures (currently ACG, Shah Deniz, Umid, Absheron and also from the next wave of production in the future) offshore in the Caspian Sea.

***Prospects for SOCAR/Azneft gas production***

According to figures obtained from the Azneft production unit, SOCAR is going to invest in drilling new wells to increase gas production from Bulla Deniz and will also invest in increasing production from Oil Rocks up to 2025. After 2025 gas production from these fields will experience its natural decline (Figure 59).

Also, SOCAR is planning to increase the production portfolio by quadrupling production at the Umid field from 311 mcm in 2017 to 1.26 bcm in 2020 and 3 bcm in 2024.

***Figure 59. Azneft/SOCAR Gas Production Projection, Including PSAs and JVs, mcm (2010-2040)***




***Sources: Azneft production unit of SOCAR, SOCAR Oil & Gas Production department***

## 4.5 Technical Resources: Nakhchivan, Zafar-Mashal, Inam, Araz-Alov-Sharg, Kapaz/Sardar

Azerbaijani geologists identified through seismic surveys a number of prospective structures in the Caspian Sea from the 1960s to the 1980s. These structures (which have not yet been the subject of exploration drilling or, where this has been done, the results were inconclusive) in the Azerbaijani sector of the Caspian Sea are Nakhchivan, Zafar-Mashal, Alov-Araz-Sharg, and Inam. Some of these fields are shown on Figure 59. In addition to the constraints of drilling rig availability some of these prospects suffer from other challenges such as high reservoir pressure and large pressure differentials between reservoir layers, potentially making them complex and costly to develop. In addition to the geological risk that such prospects may not yield sufficient hydrocarbons to be commercially viable, technical drilling challenges as well as considerations of ultimate sales price and market requirements make it difficult to estimate the possible timing of future field development and hence production start. For that reason, all timings discussed below are only indicative.

The projection of the timing of first gas from these blocks is based on analysis of the current status of a block, the motivation of the companies developing the block, availability of drilling rigs by the time it is decided to start exploration, and the addition of at least 4 to 5 years in total for the exploration, appraisal and development phases. Seismic studies of all the exploration prospects have been completed and available estimates of probable reserves (in the event of a successful exploration well) were made based on these studies. In some structures at least, one well has been drilled with existing rigs, and as a result either abandoned (considered as economically not profitable to pursue with development at given time, e.g. Zafar-Mashal), or yielded dry wells (Inam), or appeared to be technically and geologically challenging and costly (Nakhchivan). As a consequence, some of those fields have been relinquished by the consortia that began to explore them.

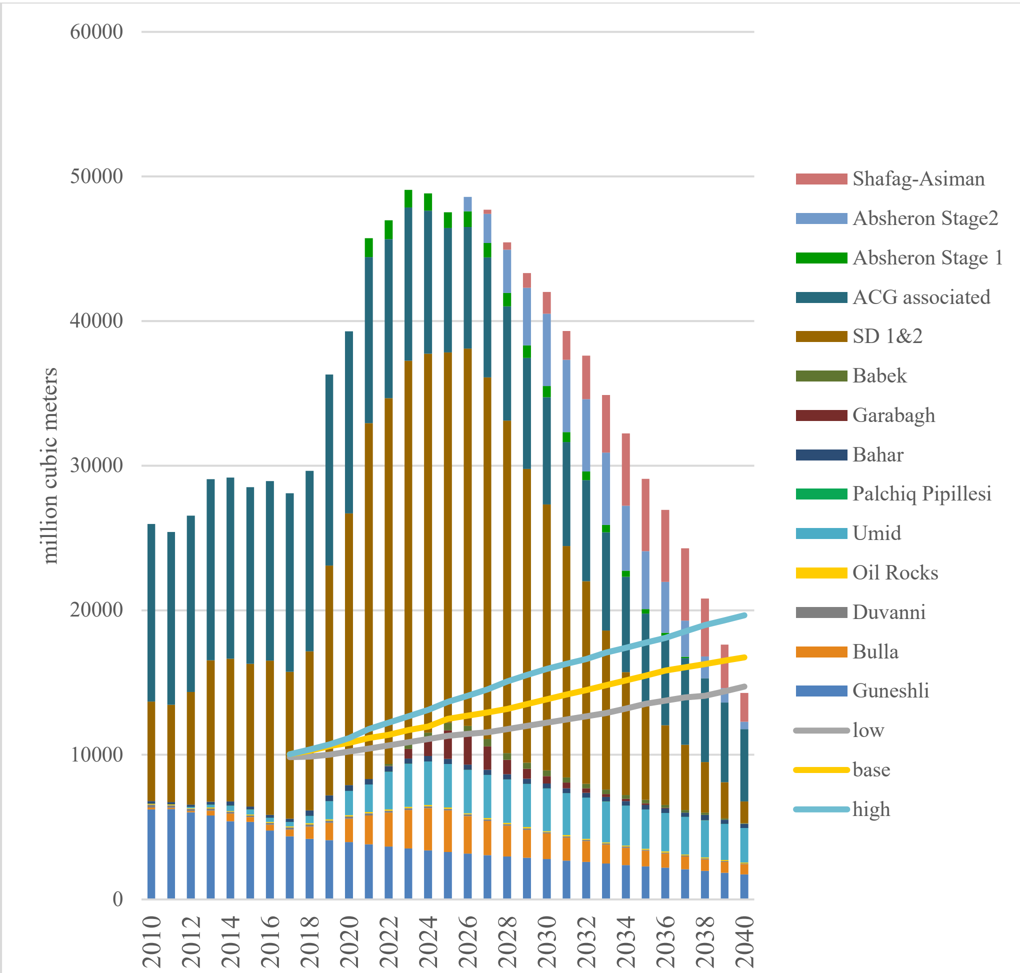
There are also structures with difficult political access, i.e. ownership is disputed with the littoral states such as Iran (Alov-Araz-Sharg) and Turkmenistan (Kapaz/Sardar). Apart from seismic study, no other work can be conducted in those areas, pending the resolution of differing territorial claims. Almost all of the exploration prospects in the Azerbaijani sector of the Caspian Sea are licensed to companies that in many cases do not have a firm plan for exploration, appraisal or development. This however is certainly not helped by the rig availability situation. Due to the difficult drilling conditions, a significant number of drilled offshore prospects have not been fully evaluated. As a result, some of the wells which did not originally prove up hydrocarbons, might yet be discovered to be successful if they are re-drilled and tested successfully.

## 4.6 Summary

As described in this chapter, Azerbaijan gas production will increase significantly by 2021 and reach its peak production in 2023. The peak production period will be from 2022-2023 to 2028-2029, when production will reach almost 50 bcm/year from around 30 bcm in 2018 (Figure 60). The fields that are included in the overall gas production projections are: producing (SD 1 & 2, fields under Azneft production, ACG associated gas and Umid); under development based on PSA or JV (Absheron, Garabagh); or where a PSA has been concluded, there is an existing consortium and partners have a firm intention to develop the fields in the mid-to-long-run (Absheron Stage 2, Shafag-Asiman). The so-called technical resources (Nakhchivan, Zafar-Mashal, Inam, Araz-Alov-Sharg, Kapaz/Sardar) were not included as, although these structures have been discovered and some preliminary 3D seismic data exists, there is no intention and plans from SOCAR and IOCs to invest in and develop the blocks and no legal arrangements are in place. The development of this group of structures will largely depend on political decision, technical (availability of drilling rigs), and commercial (the cost of gas production and marketing arrangements) factors. For that reason, any assumptions on possible gas production quantities and timing of production will be only indicative.

According to Figure 60, the country's gas demand is projected to be up to 11 bcm/year in the low case scenario, up to 12 bcm in the base case and up to 13 bcm in the high case scenario by 2025, the peak production year in Azerbaijan. Figure 61 shows the committed export volumes and gas production including ACG non-commercial associated gas. In Figure 61 shows gas production including ACG re-injected gas as well as committed export volumes with gas demand in all three scenarios. With this non-commercial gas, the surplus of gas is shown to be around 15-16 bcm/year from 2022 to 2028. In Figure 62 we excluded ACG re-injected gas, somewhat around 10 bcm till 2025, with gradual fall in the following years as a result of natural decline. Consequently, as demonstrated in Figure 63, potential gas surplus volumes that may be available for uncommitted export will be around that 10 bcm/year till 2027 in the low case consumption scenario, and around 5 bcm/year and 3 bcm/year in the base and high case scenarios respectively. The SGC pipelines, which include SCPx, TANAP and TAP are scalable to up to 30 bcm/year to transport larger volumes. According to a SOCAR official, there are plans to further expand SCP (future expansion, SCP fx) to 30+ bcm/year if additional volumes of gas are available for export and if economics allow, with the help of compressors.

*Figure 60. Azerbaijan Gas Production Projection (Includes SOCAR/Azneft Gas Production Portfolio, Probable Reserves and Excludes Technical Resources), (2010-2040); and Gas Demand Projection (2017-2040)*

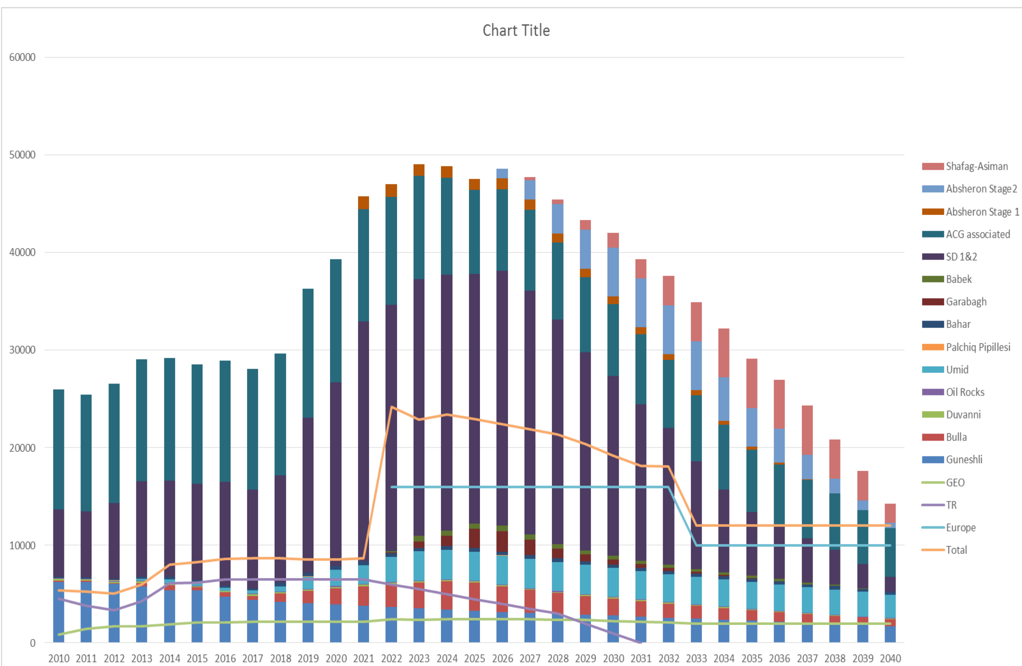



***Sources: SOCAR, Aznef, for Absheron stage 2 and Shahfag-Asiman – Author's projection.***

As TAP is European infrastructure, any decision to expand the capacity should be in compliance with the EU legislation. The decision will also largely depend on the economics of such investments and availability of markets and the price. With a maximum 10 bcm/year of gas surplus it will not be possible to fill the infrastructure fully and make it commercially viable. The availability of additional volumes of gas will also depend on the future investments in technical resources that were described above. Turkmen gas might be another option for filling the pipelines.

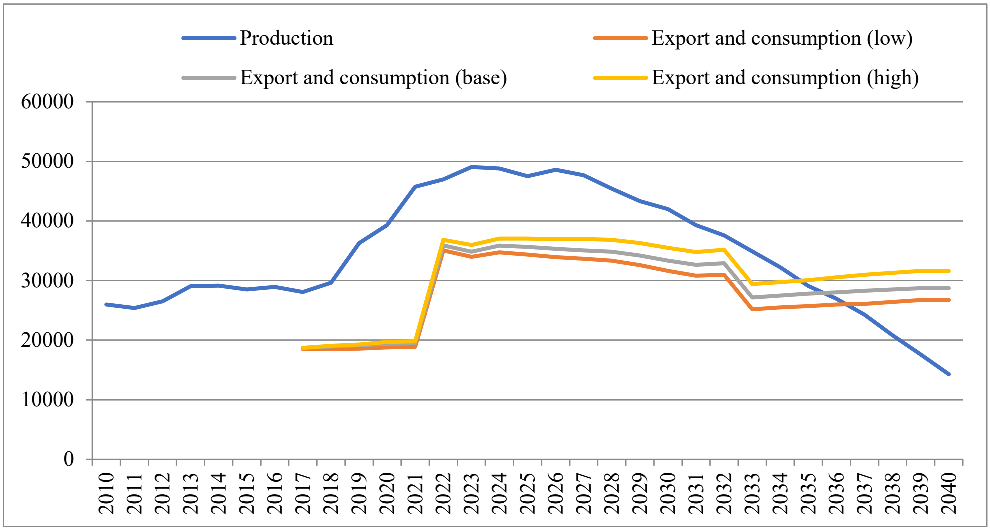
Export volumes from Azerbaijan will largely depend on whether the 6.6 bcm/year SPA with BOTAS will be renewed after 2021. As SD1 will be in natural production decline after 2024, we assume that the contract might be extended with smaller volumes and/or, because gas production will be significantly increased after 2022, additional volumes from other fields may be added to export to Turkey, if necessary. In Figure 61 we reflected the assumption of gas LTC extension with BOTAS from the SD1 field only, as any other scenarios are uncertain at this stage. Gas exports to Georgia are proportional to total volumes of gas exports to Turkey and Europe (5% of total export volumes) and around 1.3 – 1.5 bcm of SOCAR (through Gazakh pipeline) exports. There might be several other export contracts with buyers in Turkey and Europe in the future as production grows, however as this assumption is highly uncertain, we did not reflect them in Figure 62.

***Figure 61. Azerbaijan Gas Production and Gas Export Projection, mcm (2010-2040)***



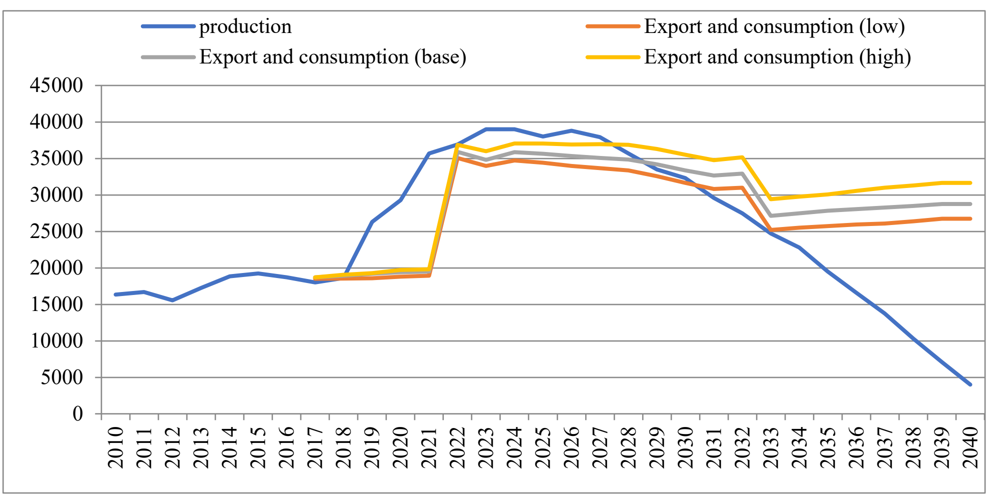

***Sources: SOCAR, Author's estimates (2030-2040).***

*Figure 62. Gas Supply Surplus & Shortage, Including ACG Re-injected Associated Gas, mcm (2010-2040)*




***Sources: State Statistical Committee, SOCAR, Author's estimates.***

*Figure 63. Gas Supply Surplus & Shortage, Excluding ACG Associated Gas, mcm (2010-2040)*




***Sources: State Statistical Committee, SOCAR, Author's estimates.***

## 4.7 Conclusion: Gas production import and export balance projection

Peak Azerbaijan gas production will be in the years between 2023 and 2028, when production will reach slightly less than 50 bcm/year. This includes the fields that are currently in production or where the partners have a firm intention to develop the fields in the future with PSAs and other agreements in place. This also includes around 10 bcm/year of non-commercial associated gas from the ACG field and, consequently, the commercial volume of gas will reach around 40 bcm/year. Given that demand will be moderate throughout the period, there will be around 30-35 bcm/year of gas available for export. If we deduct around 24 bcm/year of gas export from the country in 2022 when export to Europe will start, the remaining 5-10 bcm/year, depending on the consumption growth scenarios, will be in search of a market. Whether this gas will be exported to Turkey or Europe will largely depend on gas prices and availability of market niche.

Consequently, SOCAR could halt its gas imports from Russia and Iran as soon as 2020, when Azneft production will show significant growth from 5.8 bcm in 2017 to almost 8 bcm in 2021. Azneft peak production will start by 2025, when it will reach more than 12 bcm/year and then start a gradually decline, according to Azneft data. By that time, SOCAR will have significant excess volumes of gas, which can be used as feedstock to produce value-added products and/or to increase export to Georgia and start selling gas to private companies or BOTAS in Turkey.

The Southern Gas Corridor's mid-stream segments are scalable enough to export up to 30 bcm/year if and when the gas is available. However, the additional uncontracted volumes of gas will be available from 2023 only, when Umid will increase its production 6 times, the production from Bulla will be quadrupled and Garabagh and Babek fields start producing gas, in total around 7 bcm/year, according to Azneft data. Till then, the costly TANAP infrastructure will be operating on half capacity.

Chapter 5

# The Contribution of Greece in the EU’s Gas Security Policy: The case of TAP and the SGC Strategy after Shah Deniz 2

# 5. The Contribution of Greece in the EU's Gas Security Policy: The Case of Trans Adriatic Pipeline (TAP) and the Southern Gas Corridor (SGC) Strategy after Shah Deniz 2

by Dr. Theodoros Tsakiris[9]

## 5.1 Introduction

The question of European energy security and the need to diversify Europe's natural gas suppliers has focused attention on the strategic significance of Southeastern Europe as a transport hub for natural gas from the Caspian region, and potentially the Middle East and the Eastern Mediterranean. In order to meet increasing natural gas demand as the countries of the region move towards a cleaner energy mix and to reduce the overwhelming dependence of Eastern and Southeastern EU states on Russian gas imports, European authorities have been keen to promote projects that contribute to supply diversification.

In this context, the SGC (Southern Gas Corridor) Strategy plays an increasingly important role since it offers simultaneous supply and transit diversification to those EU members states, like Bulgaria and Greece, that most need it, while opening another supply gateway to Italy and via Italy to the Central EU market. Despite the initially overambitious goals of the SGCS which aspired, through the defunct Nabucco project, to transport up to 31 bcm/year to Austria, the opening of the Corridor in 2020 will constitute a notable success of the external dimension in the EU's Gas Security Strategy. The SGC supplies gas from sources of new origin that had never been tapped for EU consumption, transporting to the core EU network non-Russian gas via non-Russian routes but in very limited volumes.

Although in 2011 European Commission planners overoptimistically expected SGC volumes to cover "roughly 10-20 per cent of EU estimated gas demand by 2020" (European Commission, 2011a) the actual availability of SGC supplies, limited to 10 bcm/year by 2022, corresponds to just 2.14% of

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2017 EU demand or 2.73% of 2017 EU net imports, given the latest commercially available data (BP Statistical Review of World Energy, 2018). *The importance of the SGC supplies does not currently lie in the volume of initial exports but in the establishment of a non-Russian controlled corridor. In this regard it is important to note that over the last 15 years no other major source of new gas supply has emerged in a way that is dedicated to meet the long-term needs of the EU gas market.*

To the contrary, after 2011 as a result of the political upheaval in North Africa, Libyan gas supplies have become very unstable and have been cut by half compared to their pre-War levels of 9.75 bcm/year, while Egyptian exports, which may resume in notable volumes by early 2020, have all but disappeared (BP Statistical Review of World Energy, 2011). *In the decade to come SGC supplies will make up for the losses in Libyan and Egyptian exports in the 2010s but, at least in its original phase to 2025, the SGC will not rise to the same level of significance as Algeria or Norway*. Since 2013, when TAP was selected as the main export option for Azeri gas to the EU, Norwegian and Algerian exports have also increased without being able to balance off the steady expansion of Russian gas exports over the last five years. Algeria and Norway remain the two principal alternative corridors that supplement Russia's indispensable position as the core gas supplier to the EU.

The SGC volumes would need to triple or quadruple to around 40 bcm/y and beyond for the region to emerge as a serious alternative to Russian gas exports to the EU, as the Union is also supporting the evolution of new supply Corridors from the Eastern Mediterranean that will operate independently from the SGC either through a combination of new regional pipelines and existing LNG liquefaction facilities in Egypt or through the construction of a major dedicated pipeline such as the ambitions East Med Gas Pipeline project (Tsakiris et al, 2018; Tsakiris, 2018). Although the potential for the expansion of the Corridor's capacity exists, it is highly unlikely that such an expansion will more than double its existing 10 bcm/year transit capacity before the early 2030s. Moreover, most of future additional supplies during the 2020s are more likely to come from Azeri gas fields rather than new sources of supply such as Iran, Iraq, Turkmenistan or for that matter the Eastern Med (Pirani, 2018a).

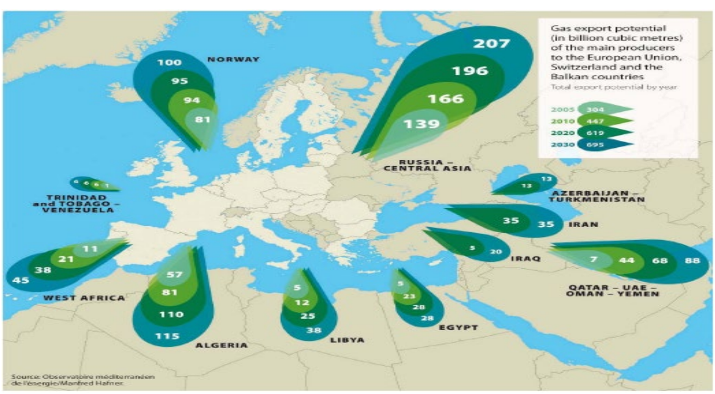
This paper first analyzes the comparative significance of the Southern Corridor within the larger context of EU Gas Security Strategy and its potential link with the Eastern Med. It then illustrates the importance of the SGC for Greek energy security. It also highlights the development opportunities created for the Southeastern EU gas markets from the construction of TAP and new "adjunct" infrastructure, namely the IGB (Interconnector Greece Bulgaria) pipeline, while focusing on the way the completion of the project affects the overall foreign energy policy of Greece.

## 5.2 The status quo of EU Gas Security: In continuous dire need of supply diversification

In late 2008 the Directorate General for Energy & Transport of the European Commission prepared a study that underlined the importance of improved interconnectivity for the future of EU gas import security which highlighted the *then,* as well as the projected flows of gas exports to the EU for 2009, 2010, 2020 and 2030. The results of the study were incorporated into the EU's 2008 Strategy for TREN (Trans-European Energy Networks) and constituted part of the background paper that underpinned the Commission's EU Security of Gas Supply Regulation (R.994/2010) (European Commission, 2008; European Parliament, 2010).

That regulation was the first serious attempt to organize an EU-wide response to serious natural gas supply interruptions like the one the Union faced in the winter of 2008-2009 between Russia and Ukraine. The Regulation attempted to forge a unified and comprehensive reaction at the Union level that was based on energy solidarity, improved physical infrastructure connectivity and the promotion of parallel prevention and emergency action plans among the various member-states on a regional basis. One of the principal conclusions of R.2010/994 was that although the EU's net import dependency would increase due to the projected drop in domestic supply, the Union would be able to cope with future risks if it increased its interconnectivity, completed the integration of its gas markets and improved the diversification of its import sources and routes.

***Figure 64. Gas Export Potential to the European Union***




***Source: European Commission (2008)***

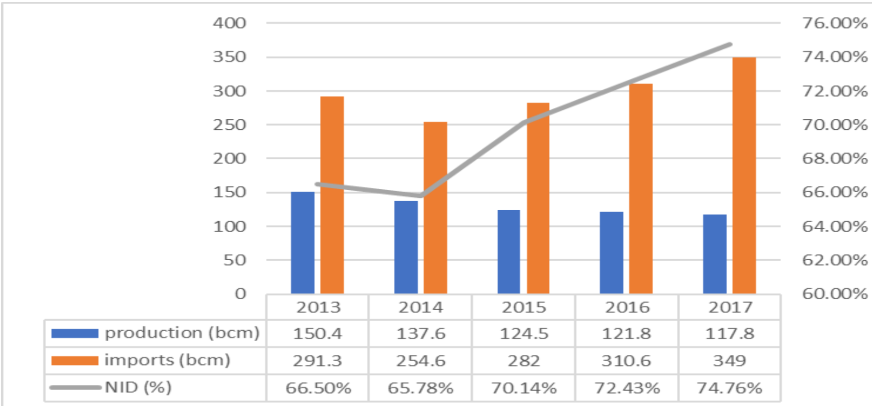
It also advocated the building of more LNG import terminals to accommodate the expected flow of additional LNG imports that were considered to be safer and more flexible from a security point of view than piped gas, which has to cross through the terrain of several transit countries (Dreyer & Stang, 2014). These conclusions are still valid today. In the ten years since the last serious EU energy supply crisis both internal interconnectivity and market integration have improved in the Union boosted by the Commission's Energy Union strategy presented in 2014 (Raines & Tomlinson, 2016).

New pipelines and LNG import terminals were constructed particularly in the Eastern member states, like the Klapeida and Świnoujście facilities, that markedly improved the import diversification of respectively Lithuania and Poland. Market integration between member-states ameliorated thanks to the expansion of physical interconnectivity as hub-based gas pricing also expanded across EU markets helping to decrease the arbitrary indexation of gas sales to crude oil and oil product prices that was imposed on EU consumers by gas exporters, including Gazprom (Stang, 2017). What has not improved though is the level of its net import dependency and the associated political risk of this dependency as negative projections of a reduction in future indigenous supply materialized at a much quicker pace than originally anticipated. In the *2014 EU Energy Security Strategy* the Commission projected an increase in the Union's net import dependency over a period of 20 years from around 62% of demand in 2010 to 65% in 2020 and 72%-73% in 2030 (European Commission, 2014b).

Unfortunately, the collapse of domestic EU gas supply has been much steeper. According to data processed from the BP Statistical Review of World Energy over the last five years, what was the projected level of Net Import Dependency (NID) for 2030 was reached in 2016. More importantly the latest available commercial data for 2017 suggest that the EU's NID continues to expand (BP Statistical Review 2018). Despite the expansion of US LNG exports to isolated EU markets, most notably in the Baltic region and Poland that have markedly improved their import diversification by securing Qatari and US LNG supplies, the Union's reliance on LNG has been decreasing steadily since 2010. LNG imports have dropped as a share of total EU imports from a high of 22% in 2010 to a low of 15.6% estimated at 48.7bcm in 2017 according to data compiled by the European Commission (2014b), IHS, and BP (2018).

The drop in LNG imports has compounded concerns over the political risk of gas supplies to the Union. LNG is the most flexible source of gas imports since the importer has a far greater portfolio of potential exporters to choose from compared to pipeline gas which corresponds to 85% of total EU imports. This 85% is essentially controlled by an oligopoly of only three principal supplies, Russia, Norway and Algeria.

*Figure 65. Rise of EU Natural Gas Net Import Dependency*




***Source: BP (2018)***

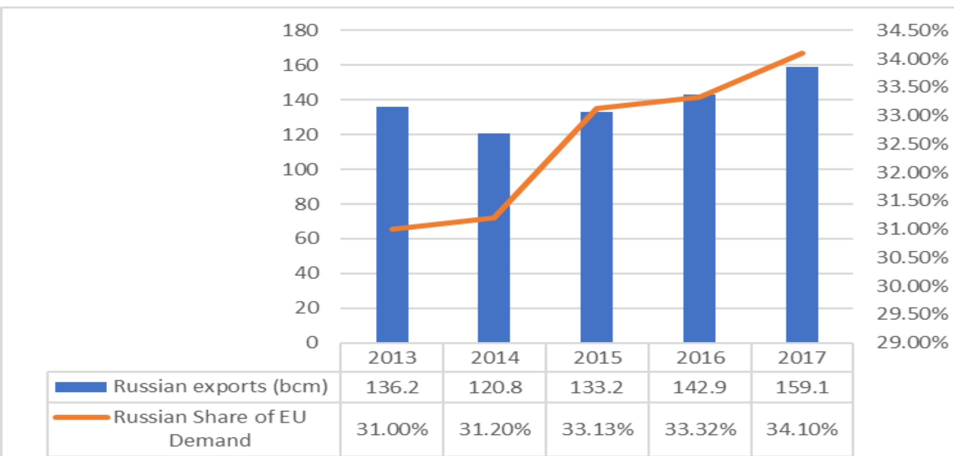
Moreover, the EU's strategic objective of diversifying away from its core supplier, Russia, and its gas pipeline export monopoly, Gazprom, has been undermined i) by the fact that Russian gas remains very competitive when compared to newer alternative supplies, and ii) by the construction of viable alternative export routes that directly linked Gazprom with its primary EU markets in Central Europe via the Nord Stream pipeline system that bypasses Ukraine (Henderson & Sharples, 2018). These bypasses have reduced the cost of transit for Russian gas to traditional EU markets and eliminated the political risk of that transit through Ukraine.

The absence of Nord Stream 1, which was commissioned between 2011 and 2013, would only have increased the possibility of a major energy supply crisis for the EU, given the two supply/transit interruptions of 2006 and 2009 and the deteriorating relations between Russia and Ukraine following the annexation of the Crimea and Russia's support for the Donbass secessionist movements after 2014. Despite the worsening of EU-Russian political relations the gas trade between the two sides is booming and appears to have been insulated from the geopolitical contentions over Ukraine.

It is important to note that the 2014 EU sanctions, contrary to US sanctions, specifically refrained from targeting the Russian gas sector and have no retroactive powers. In any case both US and EU sanctions imposed in the aftermath of Moscow's annexation of the Crimean Peninsula failed to curb Russian oil and gas production, which keeps expanding and reaching record highs every consecutive year over the last five years (B. Coote, 2018). The emergence of Germany as the pre-eminent transit country for Russian gas in the EU has stabilized the existing EU-Russian gas partnership on a long-term, basis but has also created the potential for additional Russian gas exports to the EU, especially after the projected completion of the second Nord Stream pipeline network in late 2019.

This potential is already materializing. As indicated by graph 3, despite EU efforts to diversify away from Gazprom, Russian gas exports have been steadily increasing since 2013 in both absolute and relative terms. The significance of Russian exports for EU gas security is further illustrated by the fact that Norwegian, Algerian and Libyan exports combined barely match Gazprom's EU market share. As illustrated by graph 4 Norwegian and Algerian supplies expanded between 2013-2017 at a slower pace compared to Russian exports, adding 17.7 bcm/y to their cumulative supply, *77% more than what the SGC will offer to the EU security of supply throughout the 2020s.* Exports from Libya have halved compared to 2010 and Egyptian supplies were all but eradicated as a result of the heightened political instability and related economic crisis that ensued the collapse of the Mubarak and Qaddafi regimes.

***Figure 66. Russian Gas Exports to the EU***

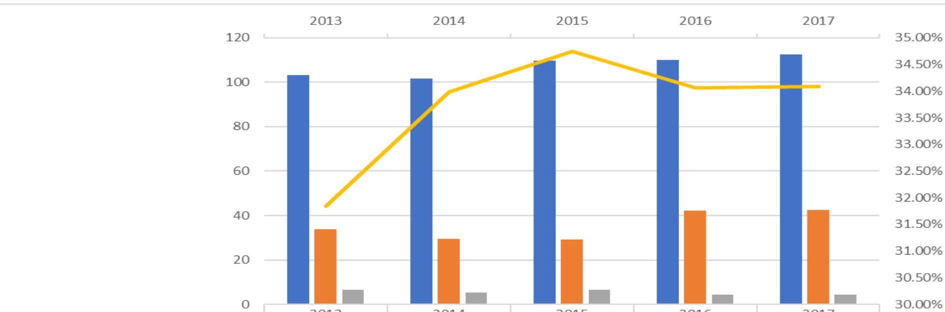



***Source: Author's calculations from BP Statistical Review of World Energy 2014-2018***

Russian net exports increased by 23 bcm/year between 2013 and 2017, more than double the 10 bcm/year of Azeri gas the EU expects to import throughout the 2020s from the Southern Gas Corridor route through the Trans Anatolian (TANAP) and Trans Adriatic (TAP) pipeline system which connect Azeri offshore gas reserves in the Caspian Sea to Italy via Turkey, Greece and Albania. This 23 bcm/year of additional Russian gas exported over the last 5 years surpasses the final technical transit capacity of the entire TAP project, estimated at 20 bcm/year. TANAP/TAP along with the expanded South Caucasus Pipeline system connecting Baku to Erzurum constitute the three legs of the SGC system. As has already been noted, the 10 bcm/y of TAP's Phase 1 is a far cry from the initial expectations that projected the importation of more than 50-60 bcm/year from the region, a scenario which would have required the export of Iranian, Iraqi (Kurdish) and/or Turkmen gas through Turkey and the commensurate expansion of transit infrastructure through the doubling of TANAP's initial 31 bcm/year throughput capacity.

TAP's phase 1 will accommodate the entire net export capacity of the second phase of the Shah Deniz field and will suffice to cover merely half of TANAP's existing transit capacity. Even if Azeri gas was available today, Norwegian, Algerian, Libyan and Azeri exports combined would account for almost 34% of EU demand in 2017. Gazprom alone currently accounts for 34.1% of net EU consumption. The need for new sources of supply diversification remains of critical importance, as critical as it was ten years ago, when the 2009 Ukrainian crisis galvanized the EU's efforts to secure the materialization its Southern Gas Corridor Strategy through the promotion of the Nabucco project.

***Figure 67. Norwegian, Algerian and Libyan Gas Exports to the EU***




| | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| Norwegian Exports (bcm) | 103.3 | 101.7 | 109.6 | 109.9 | 112.4 |
| Algerian Exports (bcm) | 33.8 | 29.4 | 29.1 | 42.1 | 42.4 |
| Libyan Exports (bcm) | 6.5 | 5.2 | 6.5 | 4.4 | 4.4 |
| Cumulative Share of EU Demand | 31.84% | 33.98% | 34.74% | 34.06% | 34.09% |

***Source: Koranyi (2014)***

This goal was only partially achieved in 2013 through the commitment of around 16 bcm/year of Azeri gas to the TANAP/TAP pipelines of which only 10 bcm/year will reach EU markets by the early 2020s (Koranyi, 2014). What the EU will gain up to 2025 from a diversification point of view through tapping into the reserves of Shah Deniz 2, it has already "lost" due to the curtailment of Libyan exports and the loss of Egyptian supplies in the 2010s, both of which fell victims to the region's structural destabilization in the aftermath of the 2011 Arab revolutions. This is the measure of the SGC's significance as far as TAP's Phase 1 is concerned when viewed within the greater context of the EU Gas Security Strategy.

Even TAP's initial achievement has its own serious limitations. Turkmen dependency on China, continued Turkmen-Azeri geopolitical friction and commercial divergence, widespread instability in Northern Iraq and the steady deterioration of US-Iranian relations after President Trump's new sanctions on Tehran in November 2018 will seriously limit the availability of non-Azeri gas exports to the Southern Corridor over the next decade (Pirani, 2018a).

In recent years the Eastern Med has also been proposed as a potential contributor to the EU's Southern Gas Corridor Strategy through the construction of a pipeline from Cyprus and/or Israel to Turkey to link East Med gas reserves to TANAP (Bryza, 2014). In view of the persistent irresolution of the Cyprus problem the possibility of Cypriot gas exports to Turkey is too hypothetical to merit further consideration. This is not necessarily the case for a Turkish-Israeli pipeline that could bring to Turkey gas from the second Phase of the Leviathan field which will be available in 2025. This scenario calls for the construction of a Turkish-Israeli pipeline through the Cypriot EEZ without the prior resolution of the Cyprus problem and against the consent of the Cypriot government. Such consent is unlikely to be secured, if no major tangible incentives, such as i.e. the return of the closed city of Varosia to the Greek Cypriots, is offered to Nicosia.

In the absence of any meaningful *quid pro quo* between Ankara and Nicosia, it is highly improbable that Israel will jeopardize its strategic relationship with both Nicosia and Athens and build a pipeline through the Cypriot EEZ. Such a move would be tantamount to the recognition of the self-proclaimed TRNC (Turkish Republic of Northern Cyprus), which is recognized by none other than Turkey. Moreover, given the current "Cold War" relationship between Ankara and Tel Aviv, who both withdrew their ambassadors in May 2018, Israel is unlikely to proceed with the de facto recognition of the TRNC, a possibility it refused to consider even at the apex of its strategic alliance with Turkey during the second half of the 1990s, when it planned to construct oil, gas, and water pipelines in order to connect it to Turkey.

There are also a number of serious non-political impediments limiting the possibility of an Israeli gas transit to the EU via Turkey. Given its depth (1,500–1,800 m), length (500–550 km) and projected cost ($2-$4 billion) (Cohen, 2016), a Leviathan–Ceyhan Gas Pipeline (LCGP), would need a minimum gas contract of 10 bcm/y over a period of 15 years in order to become financially viable, namely a gas commitment of up to 150 bcm. Israel, as a result of its own regulation that commits 60% of its known reserves to cover domestic demand, only has 360 bcm available for exports. From these 360bcm one should deduct existing long-term export contracts Israeli producers have signed with Jordan's NEPCO (45 bcm) and Egypt's Dolphinous (64 bcm). Tel Aviv would have to sign off to an export license that would commit 60% of its remaining export capacity to a single market, through a single export route to a country with which it barely has any diplomatic relations to speak of. A 10 bcm/y LCGP would provide around 15% of Turkish demand – expected, according to projections by the Turkish Energy Ministry, to reach around 65 bcm in 2023 (Rzayeva, 2014).

In case a new geopolitical conflict flares up between Israel and Turkey, Ankara which is already very well diversified in terms of alternative importers would find it much easier to replace Israeli exports through importing additional volumes from Russia, Azerbaijan, Iran or for that matter Qatar, Algeria or the spot LNG market. Israel would have far more difficulty to find an alternative buyer for 60% of its available exports. That is a market power imbalance Tel Aviv needs to seriously consider before committing to such a long-term gas relationship.

Turkey's private gas traders – who, led by Turcas, are lobbying for the project – may even offer a higher price to Israeli producers compared with Egyptian importers in order to improve the pipeline's commercial attractiveness. Involvement in Turkey's domestic market makes economic sense for Israeli exporters; an attempt to transit via Turkey to the EU does not make any economic sense though – something that is basically admitted even by the leading Turkish developers of the LCGP. There are those who continue to claim that Israeli and/or Cypriot gas could merely transit to Europe via Turkey via the TANAP/TAP (Trans Anatolian Natural Gas Pipeline/Trans Adriatic Pipeline) system. However, the proponents of a Turkish transit option for East Med gas fail to take into account that:

(i) there is no connection between TANAP and the Ceyhan region; a new dedicated pipeline transporting gas from southern Turkey to the central Turkish Pipeline grid or TANAP will be required;
(ii) TANAP is fully booked for the transportation of Azeri gas exports from Shah Deniz 2 (by 2022) amounting to 16 bcm/year and from other Azeri fields in the Caspian Sea amounting potentially to another 10 bcm/year, which will come on stream after 2025, approximately the same time Leviathan Phase 2 gas will become available. That leaves only 5 bcm/year of unreserved capacity in TANAP that can be more easily, and more cost effectively booked by Iranian gas exports;
(iii) there is no free capacity in TAP for East Med gas, for the same reasons since Azeri-based producers from the Shah Deniz consortium will give priority to their own gas to cover the additional 10 bcm of TAP's Phase 2;
(iv) there is no pipeline system presently available to carry gas from the Turkish–EU border to its final EU market destinations in Baumgarten, unless a new Nabucco West project is resurrected which would need to be constructed from scratch;
(v) Under current political conditions and given the deterioration of the overall Turkish-EU relationship, the EU has nothing to gain from

increasing its transit-gas dependence on Turkey, which will only increase as SGC volumes expand and TurkStream 2 carries additional Russian exports to South-eastern Europe. The EU's transit overdependence on Turkey is partly why the Union has refrained from encouraging a Turkish option to carry gas from the Eastern Med but has offered very public and very tangible support an East Med Gas Pipeline that bypasses Turkey. As a recent comprehensive review of Turkish-EU energy cooperation prospects has concluded regarding the potential implementation of the TurkStream 2 pipeline project: "Turkey will further strengthen its role as a transit country with relevant cooperation implications for its energy partnership with the EU. However, Turkey could take advantage of its energy transit status to exert stronger political influence over the EU" (Contaloni & Sartori, 2018).

## 5.3 The regional impact of the SGC for Southeastern Europe: The case of Greece

In order to understand the impact of TAP on Greek energy security, it is necessary to first analyze the relative importance of natural gas for the Greek energy mix, the characteristics of the domestic natural gas market and the way in which TAP relates to the country's broader foreign energy policy, and in particular its ambitious "pipeline diplomacy." Greece is one of the most energy import-dependent countries of the EU, with virtually no domestic oil or natural gas production of its own. This level of import dependence is compounded by the very large share of oil in its TPES estimated in 2016 at 50% of primary supply (International Energy Agency, 2017).

According to the government's 10-year National Plan for Energy and the Climate, the aggregate energy dependence of Greece, measured in terms of all imports as a share of TPES, amounted in 2016 to 73.6%, significantly higher than both the EU (54%) and Eurozone (61,9%) average. National Net Import Dependency has notably increased since 2013 from a low of 62.17%, driven primarily by an increase in electricity and natural gas imports as Greece shifted more rapidly away from indigenously produced coal that constituted the backbone of national electricity generation (Hellenic Republic, 2018). In effect the decarbonization of its electricity mix has been spearheaded over the last decade by national obligations under the EU's 2020 Energy Strategy which required the rapid expansion of renewable electricity as a substitute for coal-based generation.

Between 2006 and 2016 the share of coal in electricity production almost halved falling from 50% in 2006 to 28% in 2016 whereas renewable electricity expanded from 9% of all electricity generated in 2006 to 23.8% in 2016 (Hellenic Republic, 2018). Given the intermittency of renewable electricity supply and the lack of internal interconnections between the mainland and many of its islands, natural gas imports played a vital role in smoothing the transition of the country's electricity system into a lower carbon footprint and keeping electricity imports in relative check, although imports almost tripled as the result of the phasing out of coal-fired electricity from 5% in 2006 to 16% in 2016.

Natural gas was first introduced into the Greek energy system in 1996 and by 2006 it had captured around 9% of TPES and 18% of electricity generation, which corresponded to almost 80% of domestic demand. By 2016 gas imports amounted to 15.2% of TPES and over 28% of electricity generation, amounting to 70% of domestic demand. Natural gas has been a relative latecomer to the Greek energy supply mix. The "gasification" of Greece's economy has progressed rapidly since the early 2000s, with demand almost doubling in just eight years from 2 bcm in 2000 to 4 bcm in 2008 (BP, 2011). The ensuing financial crisis limited the country's aggregate energy demand by over 25% and reversed the expansion of natural gas demand, which drooped to a low of 2.8 bcm in 2014. Since then, as the Greek economy stabilized, demand for gas has picked-up considerably almost doubling to 4.8 bcm in 2017 (BP, 2018).

The National Energy and Climate Plan to 2030 predicts the continued rapid increase in the consumption of gas which is expected to cover 20% of TPES by 2020, followed by a relative decline to approximately 18% by 2030 as Renewable Energy expands to cover more than 55% of the country's electricity generation mix. Gas demand increased by 10%/year from 2000-2006 but by the much smaller annual growth rate of 2.7% in 2006-2016 as a result of the vast economic contraction that followed after 2010 (BP, 2018).

Demand has been driven by electricity generation that accounted steadily for over 2/3 of gas consumption. Electricity will remain the main driver of demand, equal to 70% of consumption in 2020 dropping to 60% by 2030, as an increasing number of older state-owned lignite-fired electricity generation stations are retrofitted to run on natural gas. In addition, a number of new gas-fired stations will be constructed primarily by Independent (private) Power Producers (IPPs) led by Protergia (Mytilineos Group), TERNA and the ELPEdison joint venture between Edison and Hellenic Petroleum.

Despite a gas import dependency that has remained at 99.99% of demand since 1996, Greek energy diplomacy has been relatively successful in increasing the diversification of its supply sources and routes. Greek gas security policy has moved from total dependence upon a single supplier (Gazprom) and a single import route (as was the case between 1995-2000) to three major suppliers (Gazprom, BOTAS, Sonatrach) and three different import routes since 2007, namely the Russian pipeline via Ukraine, Romania and Bulgaria, the Interconnector Turkey-Greece pipeline and the 5bcm/y capacity Revythousa regasification terminal.

The first major step occurred in 2000 with the beginning of major LNG imports from Algeria's Sonatrach which supplies the Greek Public Gas Company DEPA with 0.55-1 bcm/year on the basis of a long-term contract that expires in 2019. The second step followed in 2007 with the commissioning of the Interconnector Turkey-Greece (ITG) pipeline and the signing of a contract between DEPA and BOTAS for the supply of 0.25-0.75 bcm/year which also expires in 2019. In September 2013, DEPA signed a 1 bcm/year supply contract with the Shah Deniz consortium that it will use to replace its pricier existing Turkish imports which reached 0.6 bcm in 2017.

Starting in April 2010 and more systematically after 2011 a fourth source further increased the market's import diversification after a private gas trader consortium (M&MGas), managed to import LNG volumes from the international spot LNG market. An increase in the market's liquidity as a result of the US shale gas revolution pushed spot LNG prices below some European long-term contracts prices, which in turn helped Greek importers of LNG expand their business.

By 2017, spot LNG imports increased to almost 0.5 bcm covering more than 10% of national demand, thereby providing the country with a considerable margin of supply security, which is set to grow more dynamically as the regasification capacity of Revythousa has considerably improved following the building of its long-delayed third storage tank. The completion of the third tank in late 2018 expands storage capacity to 205.055cm and will correspondingly increase the terminal's regasification capacity.

This will allow Revythousa to cover up to around 18 days of national demand in case of a major supply emergency such as the one Greece faced in 2008/2009 as a result of Russian-Ukrainian disagreements. The third tank doubles existing storage availability although the country still needs a strategic storage facility given estimates of expanded demand over the next decade. In that sense a new private attempt to develop the Kavala underwater storage project is expected in 2019 or 2020.

This project has been included in the latest edition of the Project of Common Interest list by the European Commission and will operate as an Independent Natural Gas System-ASFA. If constructed it may hold as much as 720 mmcm, equivalent to about 18% of national demand thereby offering a far greater level of supply security compared to Revythousa. An initial assessment of the project by the Greek REA estimated the cost at approximately 240 mil EUR.

From a security point of view, its potential construction will also significantly restrict the need for new Russian pipeline exports that will arrive as an extension of Turkstream or (more likely) through an expanded ITG, through which Greece may secure the continued delivery of its Gazprom-contracted volumes in case Gazprom fully eliminates its dependence on the Ukrainian transit corridor by 2019. DEPA, the main importer/trader of Russian gas in

Greece is contracted to import a minimum of 2.6 bcm/y at least until its existing long-term supply contract expires in 2026. This would require raising the throughput capacity of ITG to 3 bcm/y from its existing 0.75 bcm/year. Such a scenario would have the negative effect of blocking additional non-Russian gas supplies that could come to the Greek market through the ITG, unless of course a much larger interconnector is constructed. If TAP Phase 2 is constructed any non-Russian imports to Greece through Turkey will most likely arrive via the existing TANAP/TAP pipeline system thereby eliminating the need for an expanded ITG. Within this dynamic context, the realization of TAP's phase 1 will considerably enhance the ability of Greece to cope with future supply crises, reduce the aggregate cost of its imports by allowing DEPA to cut off its relatively more expensive BOTAS contract supplies, and increase market openness and competition.

TAP will allow Greece to reduce its Russian imports from a high of 56.25% of demand in 2017 to less than 50% in 2020, while Bulgaria will limit its own net import dependence on Russia by a much higher degree reducing it by as much as 33%. Future exports from Azerbaijan's existing fields, including Absheron, Shafag-Asiman, and Umid-Babek, that are expected to come on stream after the mid-2020s will allow for the expansion of TAP's transportation capacity by another 10 bcm/y which will further increase the region's import portfolio, potentially facilitating the gasification of West Balkan economies through the IAP (Ionian Adriatic Pipeline) or more likely the expansion of the IGB (Interconnector Greece Bulgaria) pipeline.

Apart from increasing its security of supply, the construction of TAP will also help Greece fulfill another major goal of its foreign energy policy: the establishment of a South-North gas corridor that simultaneously achieves the interconnection of natural gas systems/markets from the Aegean Sea to the Danube and helps to partially shield Central European and Balkan states from the consequences of another disruption to Russian imports transiting through Ukraine. This system, based on the construction of four 3 bcm/year capacity pipelines, would link Hungary with Greece via Bulgaria and Romania and provide all abovementioned intermediary markets with non-Russian imports via TAP and ITG (if its capacity it expanded). This system of interconnecting pipelines would also allow for the rapid reverse-flow of gas in case of another major gas supply/transit crisis like the January 2009 Russian-Ukrainian crisis.

These interconnectors are important to the security of those member-states which are the most vulnerable to a supply shortage in the event of another Russian-Ukrainian showdown. Since all these projects are planned primarily as a means of diversifying gas imports away from Russia, they could also prove to be more beneficial to the Balkan states involved, especially those who supported the now defunct Nabucco West project (Bulgaria, Romania and Hungary). For the Eastern Balkans, the Greece Bulgaria Gas Interconnector (IGB) constitutes the first and most crucial link of this network. Despite the fact that both of Bulgaria's interconnector projects with Romania and Greece have secured grants from the European Commission that cover up to 1/3 of their cost, neither project has been completed by early 2019.

A series of regulatory hurdles related to existing long-term supply contracts between Gazprom and Bulgartransgaz, combined with bureaucratic inertia at the national level have plagued both projects, for years (Stern & Yafimava, 2017). TAP's final investment decision in 2013, which is to furnish Bulgaria with 1 bcm/y of Azeri gas from 2020, necessitated the construction of the IGB project without which the delivery of the 1 bcm/y is impossible.

Yet 2018 saw decisive progress being made on the long-outstanding issue of the IGB (Interconnector Bulgaria Greece) pipeline project, originally conceived in 2009 when it secured a €45 million grant from the EEPR.[10] It aspires to connect the two National Gas Transmission Systems between Komotini (Greece) and Stara Zagora (Bulgaria) over a distance of 182km. IGB, and is controlled by the IGI Poseidon Stakeholders and will carry 1 bcm/y of Shah Deniz gas to Bulgaria from early 2021 (the original timetable for its construction was 2012-2013). The pipeline is expected to cost a total of €240 million of which only €46 million will come from the project developers. Bulgarian imports from Azerbaijan may be increased after 2025 when more Azeri gas becomes available to EU customers via the second phase of TAP. For a second phase to exist, namely the expansion of its capacity to 5 bcm/y, IGB needs to carry regasified LNG volumes from the Alexandroupolis FSRU project if it materializes or wait for post-Shah Deniz 2 gas from (most likely) Azerbaijan. The long-term future of these two projects is clearly intertwined, although IGB will be built on a stand-alone basis, simply to connect Bulgaria to TAP. In November 2018, IGB cleared the last hurdle when the European Commission judged the project's financial mechanism to be compatible with EU state aid rules. Construction is expected to begin by late 2019 with the pipeline's commissioning scheduled for early 2021.

## 5.4 Conclusions

The opening of the SGC has been one of the most important successes of the EU energy security strategy over the last decade. Despite the limited volumes of gas from Azerbaijan that are expected to flow to EU markets starting in 2020, a new Corridor of potential gas supplies will be inaugurated in ways that simultaneously increase the EU's security of gas supply and gas transit. - TAP's initial achievement has, however, its own serious limitations. Turkmen dependency on China, continued Turkmen-Azeri geopolitical friction and

[10] EEPR= European Energy Program for Recovery. Of the 240 mil EUR, 46 will be equity finance, 45 will emanate from the EEPR Grant secured in 2009, 39 mil EUR will be investment by EU funds allotted to Bulgaria's Business & Innovation program (OPIC/2014-2020), while the remaining 110 million will come from an EIB loan to Bulgaria.

commercial divergence, widespread instability in Northern Iraq and the steady deterioration of US-Iranian relations after President Trump's new sanctions on Tehran in November 2018 will seriously limit the availability of non-Azeri gas exports to the Southern Corridor over the next decade.

Although initial expectations were over-optimistic about the contribution that Azeri gas could make to EU gas security, Shah Deniz exports are far more significant for the EU member states which mostly need it, most notably Greece and Bulgaria. For Greece the implementation of the SGC also offers the opportunity to emerge as an important transit state for the export of non-Russian gas to Italy and to its northern neighbors through the construction of the IGB pipeline. The TAP/IGB network will allow Greece to reduce its Russian imports in 2020 from a high of 56.25% of demand in 2017 to less than 50%, while Bulgaria will limit its own net import dependence on Russia by a much higher degree that will reduce Gazprom's exports by 33%.

Apart from increasing Greece's security of supply, the construction of TAP will also help it fulfill another major goal of its foreign energy policy: the establishment of a South-North gas corridor that simultaneously achieves the interconnection of natural gas systems/markets from the Aegean Sea to the Danube and helps to partially shield Central European and Balkan states from the consequences of another disruption to Russian imports that transit through Ukraine. Future exports from Azerbaijan's existing fields, other than Shah Deniz, that are expected to come on stream after the mid-2020s will allow for the expansion of TAP's transportation capacity by another 10 bcm/y which will further increase the region's import portfolio, potentially facilitating the gasification of West Balkan economies through the IAP (Ionian Adriatic Pipeline) or more likely the expansion of the IGB. Greece is set to benefit from the expansion of the SGC without necessarily imperiling its relationship with Russia that is, and will remain at least until 2026, its principal supplier of gas.

Chapter 6

# Italy: A Gas Pioneer

# 6. Italy: A Gas Pioneer

By Dr. Nicolò Sartori[11]

## 6.1 Introduction

Everything started at the end of World War II, in the middle of the Pianura Padana, in northern Italy, where a number of engineers and geologists from Agip (Azienda generale italiana petroli), Italy's national oil company, found the first deposits of natural gas. The discovery of commercially viable volumes of natural gas from well n.2, close to the municipality of Caviaga, represents a watershed for Italy's energy posture, and more in general for the country's economic path (Accorinti, 2008).

Natural gas, through the so-called process of 'metanizzazione' launched by the visionary figure of Enrico Mattei, provided a fundamental boost to the reconstruction of the country. Surprisingly, poor-in-energy-sources Italy was one of the first countries in Europe to appreciate the value of natural gas, at the time considered mostly an unwanted by-product of crude oil, and to build a large and strong industrial supply chain in this sector.

In less than a decade Eni (Ente nazionale idrocarburi), which absorbed Agip in 1953, reached a domestic production of 7bcm/year and built a transportation network of around 6,000 km of pipelines, then the third largest in the world behind the United States and the Soviet Union. Natural gas was not only used for industrial purposes but played an important role also in the transport sector: by mid-1950 more than 1,300 gas supply stations were present in Italy, with 5,000 gas-based vehicles out of a total of 97,000 vehicles and 1,300 out of 83,000 trucks registered at the national level.

Italy's success in developing a national gas industry led by Eni, went along with the ambition to expand the country's role in the international energy arena. If in the oil sector the contracts signed with Egypt and Iran at the beginning of the 1950s represent a watershed for the country's foreign energy policy, international initiatives in the gas sector took a bit longer. In 1969 a bilateral deal between Eni and Gazprom laid the basis for the long-standing gas partnership between Italy and Russia (at that time Soviet Union): the 20-year contract for 6 bcm/year of Russian gas delivered to the Italian market, and the realization of the Urengoy-Pomary-Uzhgorod pipeline (also known as the Brotherhood pipeline), which is still today one of the key arteries of European gas infrastructure, contributed to consolidate the role of gas in the

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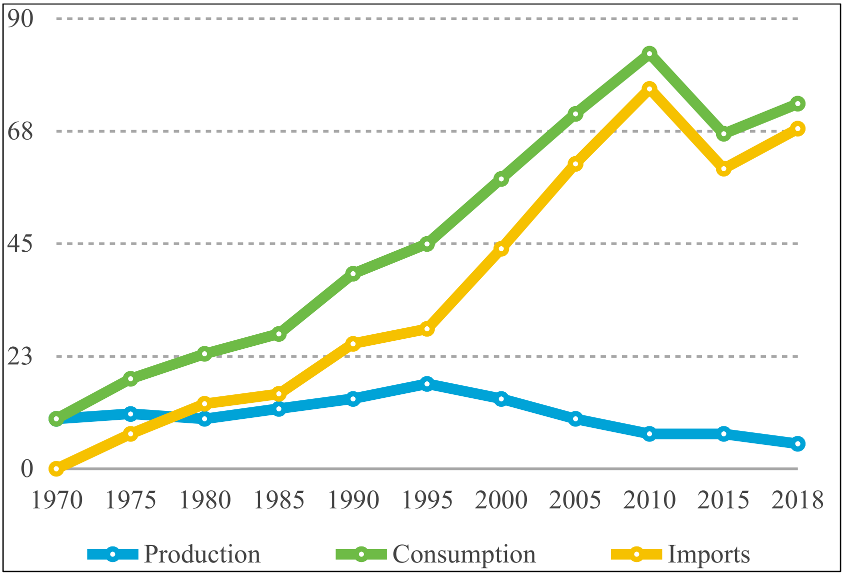
Italian energy sector by allowing the first imports from Russia, in 1972 and supporting the expansion of domestic demand.

***Figure 68. Italian Gas Supply and Demand from 1970 to 2018 (in bcm)***




***Source: ARERA (2018)***

In the decades between 1970 and 1990 Italy's consumption of natural gas grew exponentially: from around 10 bcm in 1970 to 40 bcm at the end of the 1980s. In the meanwhile, another import route was opened by Eni to meet the growing demand: the realization of the Transmed pipeline in 1984 allowed southern Italy to be connected with Algeria, one of the leading gas producing countries at the time. Due also to the popular decision, ratified by a referendum held in 1985, to abandon nuclear technology for electricity generation in the aftermath of the Chernobyl disaster, natural gas significantly increase its role as enabler of Italy's economic growth and industrial production. Domestic exploration and production activities continued throughout the decades, and reached their peak in 1994, when Italy's natural gas output totaled 19 bcm, accounting for almost half of national consumption. After that, peak output halved in less than a decade generating a situation of significant import dependence for Italy (ARERA, 2018).

## 6.2 Strategic dependence

The fundamental role played by natural gas in the Italian economic and industrial sectors, and the increasing dependence on imports to meet the growing domestic demand are two key factors for the country's energy policy, with key implications on its posture in the international arena.

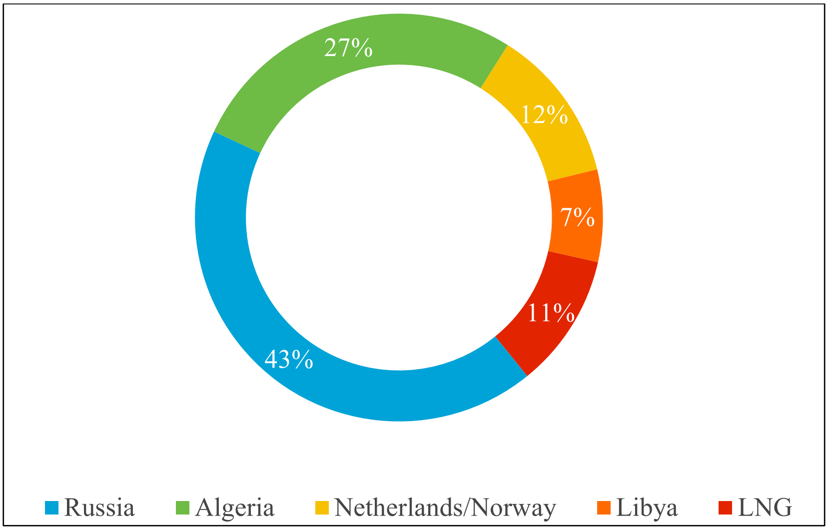
After Germany, Italy is the second largest gas market in Europe. In terms of share of natural gas in the total energy mix, the country is second only to the Netherlands, Europe's major gas producer, in particular due to the fact that nuclear capacity has been phased out starting from the end of the 1980s (a trend which is being reinforced by the decision to close coal-fired power plants by 2025). In this context, natural gas today accounts for 35% of the Italian primary energy mix, (first energy source above crude oil) and contributed to 40% of the national electricity mix (Italian Ministry of Economic Development, 2017).

In 2018 Italy consumed a total of 72.6 bcm of gas, 67.8 of which were imported. Domestic production amounted to only 5.4 bcm, the lowest value since 1963, which is partly the result of growing popular concerns vis-à-vis offshore drilling, that led the Italian authorities to slow down the exploration bidding procedures. This, in turn, reduced investment by oil and gas companies (both national and international) in the upstream sector (Italian Ministry of Economic Development, 2019).

After hitting its peak in 2010, when domestic demand reached 83 bcm and then declining due to the economic crisis until 2012, Italy experienced a steady increase in gas consumption, which halted again in 2018. The reason for this limited decline (-1.2%) is basically the growth of the contribution of hydroelectricity in the power generation sector, and the resumption to normality of electricity imports from France, which experienced a significant reduction in 2017. There was a substantial 6% growth in gas demand between 2016 and 2017.

In order to secure this vital energy source from abroad - in 2018 Italy imported 92% of its total gas demand - it has developed a virtuous strategy of diversification of its gas supplies. This is the result of a visionary approach by Italian institutions and the private sector (Eni in particular) which, during the last decades developed gas relationships with a number of key gas suppliers at the borders of Europe. Today, indeed, Italy is probably the most gas-interconnected country in the world, with four major pipeline entry points and three regasification terminals available, and other infrastructure being developed.

*Figure 69. Italy's Imports in 2018 (Percentage Per Country)*




***Source: Italian Ministry of Economic Development (2019)***

Despite this plurality of options, in 2018 Italy's gas import structure has been characterized by growing dependence on Russia (29.6 bcm) which, starting from 2012 has increased its share of Italian imports to 43%. Algeria contributes imports of 17 bcm

), and the two suppliers combined provide almost 70% of total volume imported. The North Sea (the Netherlands + Norway) with 7.7 bcm (12%), Libya 4.6 bcm (7%) and LNG (mainly from Qatar and Nigeria) with 6.7 bcm (11%) complete the list of suppliers.

Imports from Russia are delivered through the Brotherhood pipeline (crossing Ukraine and Slovakia) and the Trans Austria gas pipeline (TAG). TAG, built by Eni between 1973 and 1988 and currently owned by Italy's TSO Snam, connects Austria's Baumgarten terminal to Italy, with a total transport capacity of 47 bcm. This is Italy's main import infrastructure, the utilization rates of which are historically above 60%, although peak usage was registered in 2013 with imports reaching 30 bcm.

Looking south, Italy is supplied by Algeria through the Transmed pipeline, which connects the Hassi R'Mel field in the Algerian desert to Italian territory in Mazara del Vallo (Sicily) after crossing Tunisia and the Mediterranean Sea, with an offshore section of 380 km. The final section of pipeline, jointly owned by Algeria's Sonatrach and Eni, has a total transport capacity of 33.5 bcm, and has been underutilized since 2013, when imports from Algeria dropped by 39% (from 20.6 to 12.4 bcm) for pricing reasons. After having reached a low point in 2015 (7 bcm, less than 25% utilization rate) supplies from Algeria resumed in 2016 but are still far from its the 2010 peak of 26 bcm, when Algeria was the first gas supplier to Italy before Russia at 23 bcm.

Libya is Italy's second gas supplier after Algeria. Bilateral trade with Tripoli is much more recent, and dates back to 2004, when the Greenstream pipeline entered into operation. The 520km offshore infrastructure, the longest in the Mediterranean basin, connects Libya's Melliath compressor station with the reception terminal in Gela, Sicily. It is owned and operated by Eni and the Libyan National Energy Company (NOC), and has a total capacity of 11 bcm/year. Before the civil conflict erupted in Libya Greenstream was used at almost full capacity, with a peak of 9.8 bcm in 2008. Political instability led to the suspension of pipeline operation in autumn 2011, in the immediate aftermath of the death of Colonel Geddafi but supplies then stabilized at around 4/5 bcm/year.

Gas from the Dutch and Norwegian North Sea is an important pillar of Italy's energy security. Gas is supplied through Switzerland via the 293km Transit Gas pipeline connecting the Trans Europa Naturgas Pipeline (TENP) from Wallbach at the German border and the Snam grid at Passo Gries. Previously owned by Eni, Swissgas and Germany's E.On, to align to EU market liberalization rules the pipeline, with 35 bcm/year transport capacity - is now operated by Swissgas and Belgium's Fluxys. In the last decade imports from the North Sea progressively declined, from the 15 bcm peak in 2008, to 7.7 bcm in 2018, contributing to the increase in Italy's exposure to non-European suppliers.

LNG terminals contribute additional capacity, greater flexibility, and new import options to the Italian gas market. Three regasification terminals are currently operational in Italy: the Panigaglia onshore terminal, built at the beginning of the 1970s on the Tyrrhenian coast and currently operated by Snam (capacity 3.5 bcm/year); the Adriatic offshore terminal, realized in 2005 off the coast of the municipality of Caverzere, Rovigo, and operated by ExxonMobil, Qatar Petroleum and Snam (capacity around 7 bcm/year); and the OLT (Offshore LNG Toscana) floating terminal, owned by a consortium of Iren, Uniper and Golar LNG and located off Livorno (capacity 3.57 bcm/year). In the last few years the utilization of the LNG terminals has increased significantly: 2018 was the peak year for the use of OLT (1.1 bcm), and one of the most positive years for Panigaglia (0.9 bcm), while in 2017 Adriatic LNG reached almost full capacity (6.9 bcm). In total, in 2018 LNG imports - mainly from Qatar and Nigeria - reached 8.7 bcm, accounting for 13% of external supplies.

## 6.3 Increasing diversification

Despite its well diversified portfolio, security of gas supply remains a key priority for Italy, its government and its industrial sector. Indeed, some peculiarities of Italy's key gas suppliers require the need to monitor the issue carefully and to identify possible diversification options.

Although the gas relationship with Russia has functioned well since the end of the 1960s and Moscow has always been a reliable energy partner, the growing share of Russian gas in the national mix is still an issue of concern. Though the perceived vulnerability of Italy is much lower compared to other EU countries - in particular in central-eastern Europe - the still unresolved question of transit through Ukraine and the necessity to diversify supply routes to receive Russian gas (see analysis below) is a strategic matter for the country and is often projected to the EU fora.

Overreliance on Russia is accompanied by uncertainty about Italy's supplies from Algeria, which have partially resumed after the collapse of 2015. Algeria presents a number of political and industrial risks which might affect its reliability as a gas supplier. On the political side, the post-Bouteflika transition and the future institutional setting are fundamental to an assessment of Algeria's export potential; in particular considering past violence and the terrorist threat, which is still present, though currently dormant. The difficulties Sonatrach, Algeria's energy company, has in attracting foreign investments and expanding national production, coupled with the steady expansion of domestic energy demand, due to the absence of reliable efficiency and de-subsidization policies, might limit the capacity of Algeria to export all the volumes requested by its European customers (Italy and Spain in particular). In addition, the company's strategic decision to expand its LNG exports vis-à-vis pipeline supplies in order to increase export flexibility and profit from higher prices in regions such as East Asia, might further reduce Algeria's need to maximize pipeline exports towards Italy.

When it comes to Libya, given the levels of domestic instability and violence, any prediction of the future of national gas production and exports might be rapidly overturned by changing circumstances at the gas fields. So far supplies to Italy through Greenstream have been quite regular - though the pipeline has run for the last few years at less than 50% of its capacity - but the continuing unpredictable political and security evolution of the country suggests a cautious assessment of the reliability of its gas supplies in the future.

Finally, 'European' production is expected to substantially decrease, in particular due to the planned reduction and progressive suspension of production from the Netherlands' giant Groeningen field (the largest within the EU). The output of the field will be cut by two-thirds from 2022 and halt by 2030, to ensure the safety of people in the province, after concerns about the link between extraction activities and earthquakes (Meijer, 2019). The decision will have implications for Italy's capacity to get gas supplies from the northern route, through which it also receives Norwegian exports, the outlook for which is also under question. In January 2018 the Norwegian Petroleum Directorate (NPD) revised its gas production projections, which now show output of 121-123 bcm/year from 2018 to 2022, declining to 112 bcm in 2025 and then stabilising at 90-92 bcm/year in 2030-35 (Hall, 2018).

The diverse (but all relevant) challenges emerging on Italy's main import axes require it to strengthen its efforts to increase import diversification and to expand its capacity to attract gas supplies from different sources and through different routes. The realization of the Southern Gas Corridor (SGC) is certainly the most immediate and relevant option for Italy to expand its gas imports portfolio. The SGC, indeed, will allow Italy to receive natural gas produced in Azerbaijan, in the Caspian offshore Shah Deniz field, through a 3,000-km network of pipelines crossing five different countries and landing on the coast of Puglia, in Southern Italy. The final section of the SGC infrastructure is the Trans Adriatic Pipeline (TAP), an 878-km pipeline that was selected in 2013 by the Shah Deniz consortium to deliver its gas from the Turkish-Greek border to the EU market. TAP was selected ahead of the Nabucco West project, which aimed to transport gas to Baumgarten in Austria through the Balkans, because the Italian market looked more to appealing and remunerative to the companies involved in the Shah Deniz upstream activities (Sartori, 2013).

Although Italy's government and industrial sector welcomed the decision to build TAP and open a new import route to Italy, the approval and implementation process at the Italian level took longer than expected, due to local resistance to the project that mobilised national protests against TAP. Despite these efforts, the pipeline has been recognized as a strategic priority for Italy's energy security (but also for EU energy policy) and it is expected to be completed and enter into operation by 2020, injecting 8 bcm/year of Azerbaijan gas into the national system run by Snam, one of the project's shareholders along with SOCAR, BP, Fluxys, Enagás and Axpo.

The realization of TAP is not only a fundamental step in enhancing Italy's gas security, but it is also part of a broader attempt by Italy to become the Southern European gas hub by attracting new gas resources from the Mediterranean region and Europe's neighbourhood in general. For this reason, Italy has welcomed the discovery of the giant Zohr field off the Egyptian coast by Eni in 2015 and has advocated the establishment of an East Mediterranean gas region putting together the huge resources (some already discovered) located in the waters off Egypt, Cyprus, Israel and Lebanon. The gas volumes available in the area, particularly thanks to the presence of Eni in the regional exploration and production activities, are considered a potential contributor to further diversification of national gas imports (Tagliapetra & Zachman, 2016).

In order to consolidate its position, Italy has promoted and supported regional co-operation not only in the creation of an East Mediterranean Gas Forum (EMGF) and the signature of Memoranda of Understanding with local actors, but by presenting itself as a key player in the gas export strategies from the region. Italy is indeed among the promoters of the East Mediterranean (EastMed) pipeline, a project launched by Edison and the Greek national energy company DEPA and supported by the European Commission (which included it among its Projects of Common Interest, PCIs). EastMed is intended to connect gas fields in Cyprus and Israel to the Italian and South East Europe markets through a 1,900-km (largely offshore) pipeline. The project is currently designed to transport initially 10 bcm/y from the offshore gas reserves in the Levantine Basin (Cyprus and Israel) into Greece and, in conjunction with the Poseidon and IGB pipelines, into Italy and other South East European countries. It would also allow an additional 1 bcm/y to feed Cyprus internal consumption.

While the commercial feasibility of the EastMed pipeline - which would have the great value of directly connecting the resources in the Levantine Basin with the EU infrastructure - is under scrutiny, Italy's energy players such as Eni and Snam are in the first line to develop alternative options. Eni, which discovered the Zohr gas field and is also active in Cyprus and Lebanon, has plans to export the volumes produced through LNG infrastructure already in place in the area. Egypt's liquefaction plant at Idku and Damietta (of which Eni is one of the shareholders) has been idle for the last few years but would be ready to process and export gas produced at Zohr. In line with this strategy, in 2018 Snam signed a Memorandum of Understanding with Egypt's EGAS to co-operate in developing natural gas infrastructure. The involvement of an experienced partner such as Snam could contribute to the establishment of an offshore network to connect and pool the resources located in the area (included Cyprus and Israel), giving Cairo the role of an East Med gas exports hub. Although the 'national return' for Italy from this option would be more uncertain, because LNG volumes would be exported from the region mainly following price signals and not necessarily destined for the Italian market, playing a key role in the East Mediterranean gas game is considered a strategic priority for the country (Sartori, 2016).

Alongside having access to 'new' resources from its southeastern neighborhood, Italy pays great attention to the development of gas infrastructure in the north and its implications for national energy security. In particular, both institutional actors and the private sector are increasingly concerned by the realization of the Nord Stream 2 pipeline and the consequences for bilateral relations between Italy and Russia, the country's key gas supplier. Russia's decision to suspend the Italy-led South Stream pipeline (a decision caused in part by the firmness of the European Commission over the implementation of the EU Third Energy package) and its contemporary choice to suspend transit through Ukraine after 2019 and rely only on Nord Stream (and Nord Stream 2) to supply the European market, has been perceived by Italian political and industrial stakeholders as a huge source of strategic vulnerability for the country.

As mentioned above, Italy is the second largest destination market for Russian gas after Germany, its main manufacturing competitor, and is highly dependent on gas supplies to run its economic and industrial structure. The fact that all the Russian gas imported by Italy will transit through Nord Stream 2 (and Germany) is seen as a major loss of economic competitiveness with Berlin, because tariffs and transit costs will make the gas price at the German border much lower that what will be paid by Italian industrial consumers. To cope with this situation, Italy has tried to maintain or develop transportation routes alternative to Nord Stream 2. It has for instance tried to revitalize the Ukrainian transit option through the involvement of Snam (along with Eustream) in Ukraine's mid-stream sector. In 2017 the Italian and Slovakian TSOs signed a Memorandum of Understanding with Naftogaz and Ukrtransgaz, with the objective of maintaining the quality of natural gas transmission in Ukraine and to ensure that it is operated in a safe and efficient manner and is accessible on a transparent and non-discriminatory Third-Party Access basis, in compliance with the applicable legislation (Sartori, 2019).

The attempt to postpone the suspension of Ukrainian gas transit post-2019 is accompanied, on the other hand, by efforts to connect the Italian market through the 'new' southern gas route promoted by Russia with the realization of TurkStream. While the first string of the Black Sea offshore pipeline (15.75 bcm/year) targets Turkey's domestic gas market, additional TurkStream strings could be realized and used to reach southern and Eastern European markets. Italy has already positioned itself in this context thanks to a Cooperation Agreement between Edison, DEPA and Gazprom: the document, signed in June 2017, envisages joint efforts aimed at establishing a route for Russian gas supplies which will run from the Turkish border to Greece and further to Italy.

## 6.4 Conclusions and the way forward

Italy is a European pioneer in the gas sector, and its focus on the use of natural gas and on the issue of security of supply remains as fundamental today as it was decades ago. In this context, the use of natural gas, along with the growing penetration of renewables, is considered an integral part of Italy's efforts in the area of decarbonization and will accompany the evolution of the Italian energy sector up to 2050.

Against this backdrop, the efforts of national institutional and industrial stakeholders to ensure abundant, secure and affordable natural gas supplies remain a key feature of Italian energy policy and one of the peculiarities of its European and international dimensions. In a context of increasing uncertainty about traditional gas suppliers (i.e. Algeria, Libya, the Netherlands) and of changing trade balances vis-à-vis Russia, Italy has undertaken a proactive agenda aimed at further diversifying its already heterogeneous portfolio of gas partners, with a clear focus on its southeastern neighborhood.

If all are successful, these measures will significantly increase Italy's optionality, contributing to enhancement of the liquidity of the national gas market and - as a final result - to foster the security and the competitiveness of the country's energy, and more generally the economic/industrial sector.

Chapter 7

# Bulgaria: Small Gas Market, Big Gas Transit Perspectives

# 7. Bulgaria: Small Gas Market, Big Gas Transit Perspectives

by Plamen Dimitrov[12]

## 7.1 Introduction

Bulgaria started gas extraction from a small deposit near the village of Chiren in 1963. Since then Bulgaria's gas market has undergone a long and uneven development following the economic and geopolitical changes in the country and in the region of Eastern Europe. After long years of Russian domination, now the situation with gas deliveries in Southeastern Europe is on the verge of serious changes, because of the development of the Southern Gas Corridor (SGC) that is going to bring gas from the Caspian region.

The first aim of this article is to describe and analyze the situation in the Bulgarian gas market – short history, size, sources of supply, physical infrastructure, legal framework.

The second goal is to explore the impact of the SGC on Bulgaria in three main aspects:

- Firstly, as an additional source that can diversify Bulgaria's gas import portfolio;
- Secondly, as a source for the planned "Balkan" Gas Hub; and
- Thirdly, as an additional source for a new large transit pipeline that will be built to bring Russian gas from the Turkish Stream to the Bulgarian-Serbian border

Bulgaria is an important part of the SGC in two respects – as a consumer of gas from the Caspian region, and as a transit hub for this gas. Because of its geographical location Bulgaria is the most suitable gateway for the gas from the SGC to reach Serbia, Romania and Central Europe. Therefore, my intention is to examine the Bulgarian gas market within the broader regional dynamics in the sphere of energy trade.

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## 7.2 Bulgaria's gas consumption

2.8 bcm of natural gas and 76,200 cm of gas condensate had been extracted from the Bulgarian Chiren deposit between 1963 and 1974. After 1974, the field was used for gas storage. On 7 August 1974 the first Soviet gas reached Bulgaria through a newly built international pipeline. Since then the Soviet Union, and Russia after 1991, has had a monopoly position on the Bulgarian gas market.

Since the very beginning of the Bulgarian gas market, it has been oriented towards the needs of industry, not of households. In the 1970s and 1980s Bulgaria had several fertilizer plants and one big metallurgical complex in Kremicovci that used Soviet gas. Just before the fall of communism in 1989, Bulgaria's gas consumption reached 7 bcm/year. At that time, economic relations between the USSR and Bulgaria were not based on market principles. In 1986, the two "brotherhood" countries concluded an agreement about the development of the Soviet Yamburg gas field. Due to its participation in the extraction of gas from this field, as well as in the construction of the Yamburg-Western Soviet border pipeline, Bulgaria was to receive 3.8 bcm/year of gas.

The situation with gas deliveries to Bulgaria changed dramatically after the dissolution of the international communist system and the USSR. Most of the Bulgarian fertilizer factories that used to work with cheap Soviet gas went bankrupt at the end of the 20th and the beginning of the 21st century. They could not survive in the new market conditions. In 2009, the Kremicovci metallurgical complex was also shut down. The consumption of natural gas decreased and in the first two decades of the 21st century it varied between 2.5 and 3.4 bcm/year with one exception in 2006 when it was 3.77 bcm. There has been a small but sustainable increase in consumption in the years since 2014. This could be explained by the lower prices that followed the fall in oil prices since the second half of 2014.

***Table 7. Natural Gas Consumption Dynamics in Bulgaria in the Period 2008-2017 by Sectors (mcm)***

| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy | 979 | 970 | 1003 | 1047 | 1038 | 987 | 949 | 917 | 918 | 946 |
| Chemistry | 1073 | 627 | 743 | 914 | 743 | 782 | 800 | 1077 | 1107 | 1142 |
| Other Industries | 859 | 542 | 469 | 527 | 482 | 694 | 497 | 535 | 546 | 562 |
| Distribution Companies | 430 | 391 | 446 | 499 | 475 | 462 | 449 | 458 | 457 | 501 |
| Total | 3341 | 2530 | 2661 | 2987 | 2738 | 2925 | 2695 | 2987 | 3028 | 3157 |

***Source: Energy and Water Regulatory Commission (EWRC), (2018)***

Bulgaria's gas consumption was 3.0 bcm in 2018, almost 5% less than in 2017 (Bulgartransgaz, 2019). Yearly gas consumption per capita was 451 cm in 2017, half the average consumption in the European Union, which was 910 cm (BP, 2018).

The public gas provider Bulgargaz EAD had a strongly dominant position on the wholesale market with a share of 99.47% in 2017. The remaining 0.53% was supplied by traders (EWRC, 2018). Bulgargaz sells at prices regulated by the Energy and Water Regulatory Commission, while traders sell at freely negotiated prices to gas distribution companies and customers.

According to European Commission data, the wholesale price of gas in Bulgaria in the second quarter of 2018 was 19.92 Euro/MWh. This price was lower than the EU average, but slightly higher than Bulgaria's neighbours Greece (€18.97/MWh) and Romania (€19.65 /MWh) paid to Gazprom (EU, 2018). Soon after the release of data from the European Commission, Bulgarian state-owned company Bulgargaz issued a statement that strongly rejected the information from Brussels. According to this statement, the wholesale price in Bulgaria in the second quarter of 2018 was €17.40/MWh (BGN34.04). In this case, it would mean that Bulgaria paid the second lowest price of gas in the European Union after Portugal. Finally, it appeared that Bulgargaz used units of measurement that were different from these of the European Commission.

The share of gas in Bulgaria's primary energy consumption is approximately 15%, with the main gas consumer being the industrial sector (Bulgartransgaz, 2018). The share of electricity produced by gas is very modest – 3.7% in 2017 (5% in 2016) (EMI, 2018).

More than 42% of electricity in Bulgaria is produced by coal-fired power stations (EMI, 2018). According to EU legislation, all Member States are required to meet legally binding targets concerning greenhouse gas emissions (European Commission, 2019). The Bulgarian government, however, has no clear plans for wider use of gas for electricity production. In all likelihood, this process will be dictated by market conditions and gas and coal prices. According to some estimates, there is potential for a moderate growth in the use of gas in the electricity generation sector – 20-30% (Baringa Partners LLP, 2018). A very important factor in this context will be the development of the "Belene" nuclear power plant project. It is frozen for the time being, but Bulgaria has already paid for two reactors (1000 MW each) and is looking for a private investor to complete the project. If the NPP "Belene" is built, competition on the Bulgarian electricity market will be very strong and will diminish the chances for gas-fired power stations.

Natural gas supply in the territory of Bulgaria is carried out in the gas transmission network owned by Bulgartransgaz EAD for the customers directly connected to it and in gas distribution networks owned by gas distribution companies. According to data from the distribution companies, the total number of natural gas customers in 2017 was 96,382, of which 89,469 (93%) were households that consumed 91mcm and 6,913 (7%) non-household customers with total consumption of 476mcm (EWRC, 2018). This small number of customers was even more modest in 2016 – 87,374 and means that there was a 10% increase in a year. That is why the enlargement of the household gasification network could be the main driver of increased demand for natural gas.

Bulgartransgaz plans to expand the existing gas supply networks for households until the end of 2020 in five new municipalities - Svishtov, Panagyurishte, Pirdop, Bansko and Razlog. The government's goal is that 30% of households will use gas as a source of energy by 2020 (Baringa Partners LLP, 2018). It is now obvious that the target will not be met in the next two years, but in a situation of real diversification of gas imports and favorable price conjuncture, one can reasonably expect a significant rise in the share of households using gas. Reaching the 30% goal means that Bulgaria's gas demand will rise by 0.7 bcm/year. When considering this prognosis, one should keep in mind demographic projections that the country's population, which numbers approximately 7 million now, will fall to less than 6 million in the 2030s.

The retail gas price for households in Bulgaria in the second quarter of 2018 was €3.85/kWh, considerably lower than the average in the EU (€6.44/kWh), though a little higher than in Romania (€3.5/kWh), Hungary (€3.66 /kWh) and Croatia (€3.76/kWh) (EU, 2018). The initial investment for introducing gas for Bulgarian households is relatively high compared to the average Bulgarian salary.

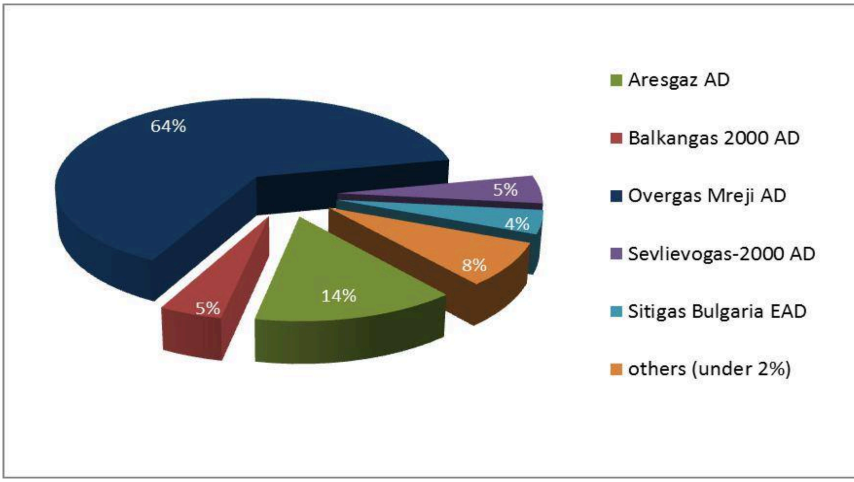
In the second quarter of 2018 industrial consumers in Bulgaria had the second lowest price in the EU after the United Kingdom. Bulgaria's price level was €2.04/kWh, while the average price in the EU was €2.35/kWh (EU, 2018).

The breakdown of natural gas consumers by companies servicing them shows a high level of concentration in this business. The company that dominates the market is Overgaz Mrezhi with 61,777 customers, which is 64% of all-natural gas consumers. Bulgarian businessman Sasho Dontchev and Russian Gazprom used to have equal shares in Overgaz Mrezhi, but in 2016 Dontchev became a majority owner of the company. Dontchev and Gazprom are in open legal conflict now after Overgaz filed a claim against the Gazprom at the arbitration court in Paris.

Aresgas, which is owned by the Italian Holding Energia Risorse Ambiente S.p.A, supplies gas to 14% of Bulgarian customers. Two companies owned by local Bulgarian municipalities – Sevlievogaz and Balkangaz hold 5% of the market each. The Herfindahl-Hirschmann index, which is a commonly accepted measure of market concentration and monopoly existence, gives a value of 4579 for natural gas supplied by gas distribution companies to household consumers in Bulgaria, and shows high market concentration (Energy and Water Regulatory Commission, 2018).

Bulgaria's national gas transmission network can meet a much bigger domestic demand. It consists of 1,835 km of gas pipelines and high-pressure gas branches, three compressor stations with total installed capacity of 49 MW, gas regulation stations, metering stations and other auxiliary facilities. Chiren, the only underground gas storage facility has a capacity of 550 mcm and operates by means of 23 exploitation wells and a compressor station with a total installed capacity of 10 MW. At present, when filled to capacity, Chiren UGS is able to supply about 25-30% of daily needs during the cold winter months. By the end of 2017, only about 40% of the transmission network system's maximum technical capacity had been used. Natural gas quantities transported through the gas transmission network in 2017 were 3,471 bcm (including the quantities transported to the Chiren UGS).

*Figure 70. Share Breakdown of Natural Gas Consumers by Service Company*




***Source: Energy and Water Regulatory Commission (EWRC) (2018)***

## 7.3 Who will supply Bulgaria's gas market?

Bulgaria's own gas production is insignificant; only 0.1% of the gas consumed in 2018 was of domestic origin. The remaining 99.9% was imported from Russia under the provisions of a long-term contract with Gazprom Export set to expire at the end of 2022.

***Table 8. Natural Gas Imports and Local Production for the Period 2008 – 2017 (mcm)***

| Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Import | 3190 | 2521 | 2480 | 2563 | 2281 | 2535 | 2551 | 2911 | 3014 | 3126 |
| Local Extraction | 246 | 9 | 54 | 406 | 336 | 274 | 182 | 85 | 80 | 35 |
| Total | 3436 | 2530 | 2534 | 2969 | 2617 | 2809 | 2733 | 2996 | 3094 | 3161 |

***Source: Energy and Water Regulatory Commission (EWRC) (2018)***

There are two main options before newcomer suppliers to the Bulgarian gas market – either to contribute to meeting the growth in demand or to substitute some of the volumes supplied by Gazprom. As illustrated below, Bulgartransgaz projects that demand will rise by 33% in the period 2019-2028. Domestic production is also expected to register a growth, while the imports are expected to stay flat at the level of 3.2-3.3 bcm/year from 2021 onwards.

***Table 9. Bulgaria's Gas Demand and Imports for 2018-2028 (estimation), in bcm***

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| Demand | 3.2 | 3.3 | 3.6 | 3.8 | 4.0 | 4.1 | 4.15 | 4.17 | 4.27 | 4.27 |
| Import | 3.14 | 3.1 | 3.2 | 3.2 | 3.3 | n/a | n/a | n/a | n/a | n/a |

***Source: Bulgartransgaz EAD (2019)***

The prognosis for domestic production is conservative as Bulgartransgaz expects it will be 0.7 bcm in 2023. There is only one very small gas deposit in Bulgaria that is in production now. It is worth mentioning that in 2012 the Bulgarian parliament entirely prohibited hydraulic fracking (breaking shale with high-pressure injection) in the exploration and production of oil and gas in its territory. The only hope for significant domestic gas production is related to the exploration of the “Khan Asparuh” and “Khan Kubrat” blocks in Bulgaria's economic zone in the Black Sea.

Permission for exploration of “Khan Asparuh” in the deep offshore part of the Black Sea was given in 2012 to a consortium led by French Total, with Austrian OMV and Spanish Repsol (30% each). Two exploration wells were drilled and the third started at the end of 2018. Another consortium, comprising well-known international companies, is to drill the first exploration well at the “Khan Kubrat” block. Shell holds 50% of this block, with Australia's Woodside (40%), and Repsol (20%). One fact should be made clear – both offshore blocks are prospective, although there has been no confirmation of the existence of commercial reserves of natural gas so far. It means that we cannot consider that gas from the Bulgarian economic zone in the Black Sea (if any) will enter the domestic market by the mid-2020s.

It is expected that Romania will become a net exporter of gas at the beginning of the 2020s mainly due to the newly discovered deposits in the Black Sea. International companies such as ExxonMobil and OMV are involved in the Romanian offshore projects. However, it is rather unlikely that Romanian gas will be directed to the small and not very lucrative Bulgarian market. The Romanian parliament has passed a law imposing a 50% domestic supply obligation for investors in the offshore fields. It is more logical for Romania's gas surplus (if any) to be exported to Central Europe – Hungary has already agreed with ExxonMobil to buy gas from the Neptun offshore block.

Until the beginning of 2019, Gazprom was the only supplier of gas for Bulgaria, and there is only one certain option for diversification of supplies in the short term. Bulgargaz has a contract to purchase 25 bcm from the Azerbaijani Shah Deniz field at a rate of 1 bcm/year during the contract period (Socor, 2013). Thus, successful completion of the SGC will secure the diversification of Bulgaria's gas supplies.

Another option for non-Gazprom deliveries of gas to Bulgaria is related to the plans to build an LNG terminal near Alexandroupoli in north-east Greece. Bulgaria intends to become a shareholder in this project with a stake of 20-25% (Reuters, 2018). Deliveries from Alexandroupoli LNG terminal are however conditional: it is not clear yet whether the European Union will provide a substantial grant for the construction of the terminal and the Final Investment Decision has not been taken yet (LNG World Shipping, 2019).

In March 2019, Bulgargaz announced a procedure for purchasing gas for the second quarter of 2019. Greek DEPA won the bid and will deliver 144 mcm to the Bulgarian energy company for its first ever purchase of gas outside its long-term contract with Russia's Gazprom. Besides DEPA, Colmar from the Netherlands and Bulgarian Dexia entered the bidding. All offered gas at lower prices than deliveries under the Bulgargaz long-term contract with Gazprom. DEPA offered gas "originated in the national gas system of Greece" while the other two companies intended to deliver gas from the LNG terminal in Revythoussa. It became possible for them to beat the Gazprom price because at the beginning of 2019 LNG became cheaper than pipeline gas in Europe. Bulgargaz declared that it continues to closely monitor the dynamics of gas prices and may organize new auctions in the future.

As far as gas importation is concerned, one can expect Gazprom to keep its dominant position on the Bulgarian market, though Bulgaria's EU membership has brought some new nuances to the picture. In recent years, the European Commission has received additional legal instruments to influence gas markets in the member states. Generally, the EU goal is to create a single market for gas and electricity in Europe, promoting competition, interconnectivity and unbundling energy suppliers from transmission network operators (European Parliament, 2009). In Bulgaria the public gas provider Bulgargaz and the operator of the transmission network Bulgartransgaz are subsidiaries of the vertically integrated, state-owned Bulgarian Energy Holding (BEH). In practice, one subsidiary of BEH controls the gas infrastructure and the only storage facility in the country, and another one supplies gas to customers. This ownership structure is not favourable to free market competition.

In December 2018, the European Commission decided to fine BEH Group and its subsidiaries Bulgargaz and Bulgartransgaz €77million for blocking access to key natural gas infrastructure in Bulgaria. Commissioner

Margrethe Vestager, in charge of competition policy, justified this decision: "For years, Bulgarian natural gas consumers have been denied a choice of suppliers because the BEH group refused to give access to its gas infrastructure to other wholesale gas suppliers". The European Commission decided that BEH and its subsidiaries had abused their dominant positions both in the gas infrastructure markets and in the gas supply markets in Bulgaria. And in detail: Between 2010 and 2015, the BEH Group blocked the access to the following gas infrastructure: the domestic Bulgarian gas transmission network; the only gas storage facility in Bulgaria; and the only import pipeline bringing gas into Bulgaria, which was fully booked by BEH. In March 2019, BEH decided to appeal the fine of the European Commission.

Members of the Bulgarian Government commented that the EU Commission's enforcer had demanded that, in order to avoid a fine, Bulgaria must sell a majority stake in Bulgartransgaz to a European strategic investor as a guarantee that the market would not be distorted. It became clear that such an option was unacceptable for Bulgaria, first, because the Bulgarian Government considers the gas pipelines and the storage at Chiren as a strategic infrastructure, and second because, according to the plan of the Ministry of Energy, Bulgartransgaz will be the operator of the future Bulgarian "Balkan" gas hub. Thus, in the near future the ownership structure in Bulgaria's gas sector will remain unchanged, but the country will be under the monitoring of the European Commission.

## 7.4 Bulgaria's potential as a gas transit country

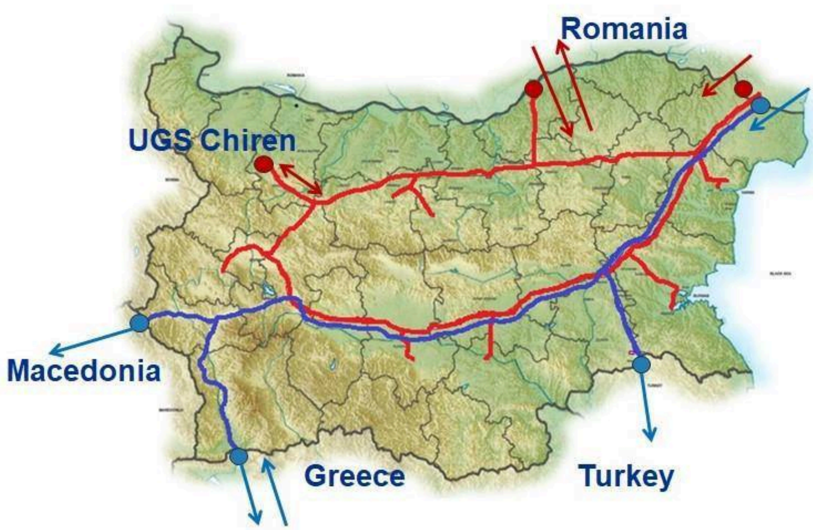
Bulgaria started to transit Russian gas to Turkey in 1988, to Greece in 1994, and to the Republic of North Macedonia - in 1995.

The Bulgartransgaz transit transmission network comprises 953 km of gas pipelines and six compressor stations, with an approximate total installed capacity of 270MW, an electrochemical protection system, cleaning facilities, a communication system, an information system, and other ancillary facilities. Bulgaria's total capacity for natural gas transit transmission to the three countries amounts to 17.8 bcm/year, while the maximum working pressure is 54 bar (Bulgartransgaz EAD, 2018).

For the time being, Bulgaria has only one gas interconnector with a neighbouring country that is not committed to the transit of Russian gas, the Bulgaria-Romania interconnector (between the towns of Ruse and Giurgu), which was completed in November 2016. The total length of this interconnector is 25 km with a capacity of 1.5 bcm/year from Bulgaria to Romania, and 0.5 bcm/year from Romania to Bulgaria. Due to the lower pressure in the Romanian gas transmission system, in the initial stages only gas flow from Bulgaria to Romania is possible. In order to enable reverse flow – from Giurgu to Ruse - a compressor station will be built later on.

In 2017, transit volumes transported through the Bulgartransgaz transmission network were 16.4 bcm. The destinations of the gas were as follows: Turkey 13.2 bcm, Greece 2.9 bcm, and the Republic of North Macedonia - 275 mcm (EWRC, 2018). The transit to Turkey declined by 18.7% in 2018 and this trend has deepened in the first two months of 2019.

***Figure 71. Transmission Infrastructure Map of Bulgaria***




***Source: Bulgartransgaz EAD (2018)***

In recent years, Bulgaria's domestic gas consumption has been about 5 times smaller than the volumes of Russian gas transited through the Bulgartransgaz network. Therefore, Bulgaria is more important as a transit country for Gazprom than as an end consumer of gas. Though difficult to prove, it is possible that the price of Russian gas paid by Bulgaria has partly depended on the eagerness of the country to be involved in the Gazprom's large transit pipeline projects.

In the 21st century, Bulgaria is trying to improve its positions as a gas transit country. It used to be an active participant in the Nabucco project, which failed due to lack of gas to fill the big pipeline from the Caspian Sea to Central Europe. Bulgaria was also involved in the Russian South Stream megaproject, which was intended to bring 63 bcm/year of gas through the Black Sea to the Bulgarian coast and further on – to Central Europe. South Stream failed in 2014 because it did not comply with the requirements of the so-called Third EU Energy Package. Russia decided to replace South Stream with TurkStream.

On 19 November 2018, the official opening ceremony of the offshore section of TurkStream was held in Istanbul. The two lines of TurkStream, each with a capacity of 15.75 bcm/year, are on track to be operational by the end of 2019. The first line will supply Gazprom's Turkish clients, and the second is designed to deliver Russian natural gas to European countries.

The TurkStream factor is poised to change the geography of gas deliveries in south-eastern Europe and thus warrants reconsideration of Bulgaria's role as a transit country for natural gas. The gas imports of all Balkan countries except Turkey are very modest and cannot accommodate the big volumes that Russia is able to deliver via Turkish Stream.

Once TurkStream is completed, Bulgaria will lose its role as a transit country for Russian gas delivered to Turkey via the Trans-Balkan pipeline. To avoid a serious loss of income from transit fees ($110 million/year), Bulgartransgaz has invited Gazprom to transfer its gas to Serbia and central Europe via Bulgaria, using the second string of TurkStream.

Bulgaria intends to use the Trans-Balkan pipeline in reverse mode and to transfer Russian gas to Provadia, near Varna, in the north-east of Bulgaria. From this point, the gas is to be transferred to the border with Serbia and further on to Hungary and to the Austrian Baumgarten hub. To implement this plan, Bulgartransgaz intends to build a new 484-km pipeline, and two new compressor stations in northern Bulgaria, which will concur with the South Stream route. The provisional cost of the project is BGNB277 billion (€1.42 billion) without VAT. Bulgartransgaz intends to invest BGN497 million from its own resources and to take a loan for the remaining part of the sum. With VAT and interest on the loan, the total cost of the project will exceed BGN3.5 billion (€1.79 billion). On 21 December 2018, Bulgartransgaz launched an Open Season procedure for the reservation of transmission capacity on the pipeline route from the Bulgarian-Turkish to the Bulgarian-Serbian border. After the completion of the binding phase 3 of the procedure, 100% of the offered capacity has been reserved by 3 companies – Gazprom, Bulgargaz and Hungarian MET Group (registered in Zug, Switzerland) (Bulgartransgaz, 2019). It is obvious that all these companies intend to transfer Russian gas coming through the TurkStream pipeline via Bulgarian territory.

Being a major new gas infrastructure, the planned pipeline from Provadia to Serbia must be approved by the European Commission. It will be hardly possible to use the new pipeline to transfer only Russian gas since it will become obvious that there is no diversification of gas sources for Europe. Bulgarian Minister of Energy T. Petkova declared that 10% of the pipeline capacity at the entry point at the Bulgarian-Turkish border and 20% at the exit point at the border with Serbia will be reserved for the access of other companies that are not connected with Gazprom. There has been no clear sign from the European Commission if 10-20% free capacity of this pipeline will be enough to meet the requirements of the EU energy law. Russian state leadership is not convinced that the EU will approve this scheme for the use of the Bulgarian gas transit network. During his visit to Sofia at the beginning of March 2019, Russian Prime-Minister Dmitrii Medvedev said clearly that Moscow is waiting for guarantees from the EU.

It is very likely that Bulgaria will have long and difficult negotiations about the scheme of use of the planned gas pipeline to Serbia. Under such circumstances, the perspectives for gas deliveries from the SGC could change the picture. If some volumes of gas from Shah Deniz field and from the planned LNG terminal in Alexandroupoli are directed to Serbia and Central Europe through the Bulgarian transmission network, the European Commission could be convinced that the new infrastructure will not be just a transit pipeline that will strengthen Russian dominance on the South-East and Central European gas markets.

Bulgaria also relies on gas from the SGC to supply the “Balkan” Gas Hub, a project that the government has been insistently pushing. The concept of building the “Balkan” Gas Hub has been included in the European Commission’s list of PCIs of 18 November 2015 and also in the Third EC PCI list, published on 23 November 2017. The EU provided 50% of the cost of the feasibility study of the project (European Commission, 2017).

The idea of building a regional gas hub is supported by the strategic geographical location of Bulgaria and well-developed existing gas transmission infrastructure. In January 2019, a new company – Gas Hub “Balkan” EAD was set up as a subsidiary of Bulgartransgaz. The creation of the subsidiary was pursuant to the decision of the Council of Ministers and the Parliament to amend Bulgaria’s 2020 energy strategy.

According to the official “Balkan” Gas Hub concept, the new infrastructure will rely on many natural gas sources: Russia, Romania’s Black Sea deposits, Azerbaijan, the eastern Mediterranean, the LNG terminals in Greece and Turkey, and potential domestic production from Bulgaria’s exclusive economic zone in the Black Sea. However, these expectations are too optimistic. In reality, Romania has not yet started extracting gas from the Black Sea and has not expressed any intention of transferring it to Bulgaria. Meanwhile, the LNG terminal in Alexandroupoli is not yet in existence; there is no pipeline from the eastern Mediterranean to the Balkans, and no evidence of commercial gas deposits in Bulgaria’s exclusive economic zone in the Black Sea.

Therefore, in short and midterm perspectives the “Balkan” Gas Hub can rely only on gas deliveries from Russia and the SGC. The infrastructure that brings Russian gas to the Bulgarian territory exists; however, at the beginning of March 2019 Gazprom chairman Alexei Miller stated that his company will not participate in the “Balkan” Gas Hub because all Russian resources in the region of south-eastern Europe are contracted on a long-term basis.

Consequently, the gas from the SGC is of crucial importance for the fate of the “Balkan” Gas Hub. It is expected that gas from the SGC will reach Bulgaria via the Interconnector Greece-Bulgaria (ICGB) by the beginning of 2021. On 8 November 2018 the European Commission approved state support for the ICGB and confirmed that this project will receive a grant of €45 million from the European Energy Programme for Recovery. The ICGB can also rely on an additional grant funding of around €39 million under the structural EU funds for Bulgaria and on a long-term loan of €110 million granted by the European Investment Bank to BEH (and subsequently passed-on to ICGB AD), secured by a Bulgarian State Guarantee in the same amount. It means that the project looks financially viable. In August 2018, the national regulators of Greece and Bulgaria adopted a Final Joint Decision for the exemption of IGB from the requirements of art. 36 of the 73/2009/EC gas directive regarding third party access, regulated tariff and ownership unbundling.

In order to develop the “Balkan” Gas Hub, Bulgaria intends to build new interconnectors with its neighboring countries. One of them is a gas interconnector with Serbia, which was announced by the European Commission as a project of common interest. This project is different from the above-mentioned transit pipeline that will reach Serbia via northern Bulgaria. In January 2017, a Memorandum of Understanding for the interconnector was signed by the energy ministers of Bulgaria and Serbia. The implementation of the first project phase of the Bulgarian section was completed at the end of December 2015 with funding from the EU. Significant progress has also been achieved in securing funding for the project from Serbia. Negotiations were finalized with the EC to secure the necessary funds under the pre-accession EU instruments and currently the pipeline section Dimitrovgrad (Serbia) - Nis (Serbia) is in the design stage. Initially, the gas pipeline is expected to deliver 1.8 billion mcm/year (Bulgartransgaz, 2018). It is envisaged that the interconnector will be put into operation by the end of 2022 in the best-case scenario.

There is a plan for an interconnector Bulgaria - Turkey to connect the Bulgartransgaz and Botas gas transmission networks. It will be a new onshore pipeline with a length of about 200 km (approximately 75 km of which will be on Bulgarian territory), with a capacity of 3 billion mcm/year. The Interconnection Bulgaria - Turkey has been ranked in the list of PCI of the European Commission, although no steps have yet been taken to implement it.

It has been suggested that the existing interconnector Ruse-Giurgiu could become part of a broader gas transmission network connecting Bulgaria, Romania and Hungary (transmission corridor Bulgaria-Romania-Hungary-Austria - BRUA). It would provide bi-directional natural gas transmission between the countries for gas from the Southern Gas Corridor and the deposits in the Black Sea, and transmission of Central European gas to South-Eastern Europe with a capacity of 1.75 bcm/year for the first phase and 4.4 bcm/year for the second phase. Further expansion is envisaged in the third phase in case of proven economic profitability.

The development of the BRUA transmission corridor and the Bulgaria-Serbia interconnector has become more important after the first-round market test for the reservation of capacity at the planned Alexandroupoli LNG terminal was successful and companies from Serbia, Romania, Hungary and Austria participated in it. There is also a possibility from the mid-2020s for additional volumes of Azerbaijani gas to enter the SGC, to reach Bulgaria and to supply the "Balkan" Gas Hub (Rzayeva & Dimitrov, 2019).

In conclusion, it could be stated that Bulgaria's gas market is relatively small and dominated by one big supplier - Gazprom. The development of the SGC is a chance to diversify supplies and to improve Bulgaria's negotiating position with Gazprom. It also coincides with the policy of the European Commission to promote competition and the diversification of EU members' gas markets.

The realization of the idea of the "Balkan" Gas Hub would be impossible without resources from the SGC, so long as Russia refuses to take part in the project. And finally, the gas from the SGC can enter the planned large pipeline that is intended to transmit Russian gas from TurkStream to Serbia, and thus make this infrastructure acceptable to the European Commission.

Chapter 8

# Turkey as the New Major Transit Country for European Natural Gas: The Next Steps Towards becoming a Genuine Regional Hub?

# 8. Turkey as the New Major Transit Country for European Natural Gas: The Next Steps Towards Becoming a Genuine Regional Hub?

by Mehmet Öğütçü[13]

## 8.1 Introduction

Turkey has the opportunity to progress from being a regional gas transit country to become a hub and reshape its natural gas ambitions, given the changing dynamics in world energy markets and the new "window of opportunity" opening to revisit the existing "take or pay" contracts expiring from 2021 onwards. TANAP and TurkStream pipelines will become operational by the end of this year, reinforcing Turkey's volume and transmission capacity. Further liberalisation of Turkey's gas markets, legal and institutional framework, financial viability and the convergence of foreign/security policies and energy goals will substantially contribute to Turkey's "hub" aspiration.

Hydrocarbons are valuable only if they can be transited from where they are produced to where they are consumed. Turkey has historically been one of the most important transit corridors between the East and the West (now, increasingly the North and the South as well) and provides the only marine passage from the Black Sea to the Mediterranean Sea. Its control of the Bosphorus and Dardanelles has dictated much of the geopolitical history and economic flows of the region. Turkey is not only a major transit country but also a consumer, investor and security provider to cross-border energy infrastructure in its region.

Although it is poor in resource endowment, Turkey enjoys a privileged geographical location (sitting on one of the world's most valuable real estates) as a neighbour to 72% of the world's proven gas and 73% of oil reserves (percentages reflect the situation prior to new discoveries around the world over the past decade), in particular those in the Middle East and the Caspian basin. Its geo-strategic position between producing countries in Russia, the Middle East, the Caspian, the East Mediterranean and the consuming European market offers the prospect of acting as a bridge and contributing to enhanced European energy security. Several energy-policy errors and foreign

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policy missteps over the last few years have limited Turkey's transit potential to a certain extent, but it still has strong connections.

Turkey has four international gas import pipelines with total technical import capacity of 146.9 mcm/d (52.9 bcm/year) through which it imports gas from Azerbaijan, Iran, and Russia. Four cross-border gas pipelines are in operation: The West Gas (16 bcm) and Blue Stream (14 bcm) pipelines from Russia, the Tabriz-Erzurum (10 bcm) pipeline from Iran and the South Caucasus (6.6 bcm) from Azerbaijan. TANAP started carrying its first gas molecules to Eskisehir in June 2018. The first leg of the TurkStream pipeline was also completed in November 2018, with first gas expected in late 2019. It is unclear whether and when TurkStream-II will be able to transit Russian gas via Bulgaria to southeastern Europe in the future.

Each of these pipelines has a take-or-pay clause in its bilateral agreements, which obliges Turkey to make periodic payments of specified amounts whether the gas is delivered or not. The obligation to pay is thus independent of the consumption of the product. Due to the highly concentrated nature of Turkey's suppliers of oil and gas from Middle East countries and Russia, Turkey would benefit from diversifying its source base from both pipelines and LNG.

Certainly, TANAP and TurkStream provide three new entry points, doubling Turkey's send -out capacity and reducing the likelihood of gas shortages during times of peak demand. However, further efforts are needed to capitalise on Turkey's unique position as consumer and transit provider to bring Iranian, Iraqi, East Mediterranean and Turkmen natural gas flows into Turkey in the future without being lost in complex foreign policy and ideological wrangling.

Understandably, Turkey is not content only to be a simple "bridge" over which energy flows. It aspires to become a regional "hub" that can serve its strategic and commercial interests. Certainly, the country has the potential to become a major regional "hub," in the true sense of the word, for energy flows in the next decade or so if smarter policies can be possibly put in place to both ensure its energy security and serve as a reliable partner for producing and consuming nations, investors and operators. It is on the way to become a major transit provider, but it is currently far from becoming a hub.

Turkey's priority is to ensure energy security for its heavily energy-dependent economy, which is larger than many of its neighbours combined. Then comes serving other destinations with excess capacity as a transit country. Turkish strategists also see the turning of their country into an east-west and north-south energy corridor as part of a broader plan aimed at enhancing Ankara's geopolitical and economic role in the global system.

Turkey is already the largest economic powerhouse in the region, although its dream of becoming a trillion-dollar economy in the next few years ("2023

Vision") seems to have gone up in smoke, at least for the foreseeable future, as a result of the severe currency crisis in 2018 and the ensuing recession. The International Monetary Fund expects Turkey's nominal GDP to come in at $631bn for 2019. That would mean the country retaining its position as the world's 17th largest economy, but the anticipated output figure pales in comparison to 2017's $849.5bn.

While in the last decade it has gained praise for its strong growth performance, now it is considered to be among the "fragile five", together with Brazil, India, Indonesia, and South Africa. The biggest concern is the large current account deficit that is being financed mostly by short-term volatile capital inflows. Still, Turkey is a country that grows fast, is urbanised and hosts a growing middle class with a strong energy consumption tendency. A few years back, it was not far behind China in economic growth and the demand for energy has been continually on the increase.

Turkey's excessive dependence on external sources does not only bring heightened energy security concerns; it also brings about a serious financial drain on the economy. The energy import bill is expected to total $181.3 bn in the next three years. Energy imports cost $42.99 bn in 2018, a 15.6% increased on 2017 and 20% of the total Turkish imports of $223 bn.

This paper will consider how world energy dynamics could possibly affect Turkey's transit and hub aspirations. It will also look into new opportunities and constraints in Turkey's energy economy and geopolitics, and gas market dynamics in the EU and in the energy-rich region around Turkey, before proposing some recommendations for government and business leaders.

## 8.2 National security and natural gas

Turkey is a country with ambitious goals. Under its 2023 vision corresponding to the centenary of its foundation, it wants to enhance its regional power status in a vast geography from China to Germany, from Russia to Saudi Arabia and Africa. Ankara wants to enhance strategic partnerships with Washington, Brussels, Moscow, Tehran and Beijing to enhance its global outreach and benefit better from such wider engagements.

For a rapidly growing and ambitious country, dependent on foreign energy and capital imports, a sustainable and affordable supply of energy is not a simple energy supply issue; it is a critical national security matter. Turkey's reliance on fossil fuels - specifically natural gas coming via pipelines from Russia, Iran and Azerbaijan - poses a long-term challenge as the country possesses nearly no significant recoverable reserves of its own.

At present, domestic resources meet only a third of Turkey's total energy demand, necessitating importation of 98% of its natural gas and 93% of its oil. Turkey's natural gas consumption was around 50 bcm in 2018 after a record high of 53.85 bcm in 2017. Imports have added billions to the country's trade deficit, thus contributing to the current economic fragility, and have made security of supply an issue of vital strategic importance to the state.

Under the current circumstances, it is almost impossible to achieve energy independence, but focusing on mutually reinforcing energy interdependence is possible. The long dependence on Russian gas over the last decades is an incentive for Turkey to diversify its internal and external energy sources. There are signs of the Turkish leadership recognising the importance of a new coherent energy strategy in which renewables, nuclear, local supply sources and efficiency improvements are set to take an increasingly prominent role.

Despite the government's efforts for renewables to dominate the energy scene and reduce import dependency, natural gas is still the main source (around 30% of the energy mix) and will likely remain so in the foreseeable future - not only for power generation (down from 63% in 1999 to 29% in 2018), but also for industrial and residential use. More than half of gas imports came from Russia (with Turkey becoming the second-largest export market for Gazprom), followed by Iran (16.7%) and Azerbaijan (11.9%). It is possible that Turkey will receive additional gas from Iraq's Kurdish Region (KRG), the East Mediterranean and perhaps Turkmenistan and Kazakhstan across the Caspian in the next decade or so, if geopolitics change.

Turkey has also recognised the importance of LNG and Qatar is being the newest addition as a supplier to its current LNG-contract suppliers, Nigeria and Algeria. Floating regasification terminals (FSRUs) are also being added and will have sufficient excess regasification capacity to take advantage of spot LNG supplies. Emergency and surplus regasification capacity – coupled with the flexibility of FSRUs – should contribute to the gas supply liquidity.

A web of oil pipelines already crosses Turkey along east-west and north-south energy corridors and new ones could be added. Among the most significant is the Baku-Tbilisi-Ceyhan oil pipeline, which connects the Caspian and Mediterranean via Azerbaijan, Georgia, and Turkey - notably, without crossing Russian soil. There are also two oil pipelines from Iraq: the 600-mile Kirkuk-Ceyhan pipeline and another connecting KRG production independently to Ceyhan.

More important than the land-based pipelines, Turkey also provides free passage to Russian, Kazakh and Azeri crude oil from the Black Sea ports of Novorossisky and Supsa through the Bosphorus and Dardanelles straits, which are among the world's most important strategic chokepoints. Over 120 million tonnes of oil and oil products are transported by this route annually. A Samsun-Ceyhan bypass was proposed to reduce Bosporus congestion and protect Istanbul from a potentially devastating oil spill but has not materialised to date.

Turkey is keen to expand the capacity of existing gas pipelines and complete the construction of new ones from the KRG and the East Mediterranean.

Although there is a long way to go before or if Turkey can ever join the EU one day as a full member, the EU *acquis* influences how Turkey's energy policy has been made. Energy is too pressing an issue to wait for the Turkey accession talks to make progress, and although one way or another it will affect ongoing efforts, it is important to decouple energy from the enlargement process. The EU and Turkey would benefit mutually from enhanced energy co-operation and should now be more strategic and flexible when discussing energy.

The supply disruption risk has been a wake-up call for the Turkish leadership, particularly in the wake of the shooting-down of a Russian warplane over the Turkish-Syrian border. Turkey has now balanced its gas-supply-transit policy among four strategies: (i) aiding Russian gas flows to Europe through TurkStream pipelines, (ii) executing the Southern Gas Corridor project via TANAP and TAP, (iii) eventually providing transit for new cross-border pipelines from the East Mediterranean, Persian Gulf, and KRG of Iraq, and (iv) growing LNG supplies from its traditional suppliers and the US, as well as FSRU capacity, onshore gas exploration and storage.

The primary factors shaping these strategies are driven by geopolitical, as well as commercial factors. They involve stabilising Syria, dealing with the KRG in Iraq, balancing relations with Israel, settlement of the Cyprus dispute and sovereignty issues, and navigating balanced relations with Russia and the US, among others.

## 8.3 Global context for natural gas and transit

Turkey's new natural gas role, either as a consumer, transit provider, investor or hub, has to take into account what has happened in global gas markets. Natural gas is no longer a transitional fuel. It will overtake coal as the second-largest fuel in the global energy mix by 2030 (increasing its share to 25% by 2040).

The global importance of natural gas is expected to grow as a result of increased supplies of unconventional natural gas. The shale gas revolution will continue to expand gas production. By 2040, the IEA projects that annual natural gas production from unconventional resources will increase by 1,061 bcm/year while conventional sources will increase only by 622 bcm/year. Overall annual natural gas production is expected to increase from 3,536 to 5,219 bcm/year.

Industrial consumers will make the largest contribution to a 45% increase in worldwide gas use. Trade in LNG is set to more than double in response to rising demand from developing economies, led by China. Russia will remain the world's largest gas exporter as it opens new routes to Asian markets, but an increasingly integrated European energy market will give buyers more gas-supply. Coal-bed methane, shale gas, and tight gas have made natural gas one of the fastest growing fossil fuels. The opportunities for the growth of natural gas production in Russia are primarily expected to be driven by the export of LNG because domestic demand has remained stagnant. Hence, the increase in natural gas production has led to a rise in the production of LNG which is likely to boost the growth of the global LNG market.

The main projects set to get the go-ahead include the Arctic LNG-2 in Russia, which is securing its future as a gas-exporting giant with the development of the massive $25.5 bn project situated close to the currently operational Yamal LNG project. There are three projects in the US, Australia's emerging role as the world's largest LNG exporter should be cemented this year with the last of the current phase in new export projects ramping up. In southeast Asia, Thailand is progressing its ambition to become a regional LNG hub.

Elsewhere in the world, Africa has two LNG projects worth watching this year, including the $20 bn Mozambique LNG project, and the Fortuna LNG project situated offshore Equatorial Guinea. Whilst most of these LNG projects encompass land-based terminals, we are also likely to see the emergence of other types of LNG projects such as floating storage and regasification (FSRU) facilities and Floating Liquefied Natural Gas (FLNG) operations. This growth in LNG supply is matched by growing demand, especially amongst the emerging markets of Asia.

The steep reductions in oil prices have impacted the financials of companies involved in the upstream oil and gas sector and have a negative impact on their profit margins. Hence, the oil and gas sector has been unable to attract substantial investments, thus resulting in the loss of significant market potential. Fluctuations in global crude oil prices affect the pricing of natural gas and thereby LNG, which is likely to pose a challenge to the growth of the global LNG market.

Global demand for natural gas is expected to grow strongly thanks to increasing levels of industrialization and power demand in Asia and Africa, continued coal-to-gas switching (especially in China) and the increasing availability of low-cost supplies from North America, Australia and the Middle East. There is some concern that the global economic growth could slow down across almost all major economies. This in turn could weaken demand for oil and gas.

Asia continues to dominate LNG import demand, with overall volumes increasing at least 12 %/year. In China alone, LNG import volumes grew 52%/year. For supply, new LNG projects are expected to add 48 bcm of capacity, and LNG plant utilisation has held stable at around 82%. 2019 is set to be a record year for LNG projects being sanctioned with over 220 mmtpa of gas targeting final investment decision.

China’s rapid demand growth is expected to quickly exceed its domestic supply growth. In South Asia, the gap between declining domestic supply and modest growth in demand is expected to widen to around 20 bcm by 2022, with LNG imports from Qatar and the US expected to bridge that gap. Europe is likely to face a similar situation, with an approximately 45 bcm gap developing between declining supply and a flat demand-growth profile. As a result, we expect Europe to increase imports in pipeline gas and LNG, predominantly from existing suppliers. US shale LNG is forcing its way into the European market.

There are four major themes that stakeholders in the gas world should focus on to remain successful. First, the traditional midstream model has come under pressure from players expanding margins through trading and taking more integrated positions across the value chain. Second, transparent LNG pricing from the US has created unprecedented arbitration opportunities, with $20–35 bn at stake through negotiation and arbitration. Third, the gas-for-transport sector will provide limited upside potential even under optimistic assumptions. And finally, to secure positive margins, new LNG liquefaction projects need to be competitive against US projects at $7 per MMBtu landed cost in Asia.

Despite the glut in the market, there are still new discoveries. Exxon Mobil announced in March 2019 that it has made the world's third-biggest natural gas discovery in two years off the coast of Cyprus in the Eastern Mediterranean at the Glaucus-1 well. The region is already known for some of the world's largest such discoveries. It wants to become an alternative energy source for Europe. Based on preliminary interpretation of the well data, the discovery could represent a natural gas resource of approximately 142 to 227 bcm).

East Mediterranean is becoming a new regional gas province. Egypt will continue to use domestic gas sources well into the 2020s, as it looks to become a regional gas hub, and has announced plans to ramp up exports from its 6.9 bcm/year Damietta LNG plant. Idku, its other LNG plant, can export a total of 10 bcm/year, and Egypt has signed a provisional contract to receive gas from Cyprus’s Aphrodite field for Idku. With the successful ramp up of production from the Zohr field, the expectation is that Egypt will be over-supplied for a couple of years. At the same time, domestic market consumption is increasing, which means that the period of over-supply will be limited.

Aramco has outlined plans to increase Saudi gas production by 64% within the next ten years to decrease reliance on oil-fired generation. The move could be partially politically motivated, as a dispute between Saudi Arabia and Qatar continues. Roughly a third of the UAE's gas is supplied by Qatar through the

Dolphin pipeline and LNG exports, and Abu Dhabi's Mubadala investment company holds a stake in the pipeline infrastructure. Bahrain will begin importing LNG in 2019, and supply will be sourced entirely from the spot market.

Like most cross-border energy projects in the region, the main downside risk for progress on potential pipeline projects, or any supply risks for existing pipelines, will be geopolitical tensions. LNG could be a risk for pipeline projects. Global LNG prices are expected to fall as US and Australian supply increases. Elevated shipping rates could also put a brake on cross-basin trading.

Looking at the way gas is delivered around the world, gas consumed where produced should continue to dominate the gas mix (at about 70–75%), while the share of traded gas should grow from 25 to 28% by 2022. New gas infrastructure is expected to support the rise in traded gas flows, with new pipelines adding about 200 bcma of cross-border capacity by 2022. The largest import increases will occur in China, South Asia, and Europe.

Gas infrastructure will continue to play a vital role in providing heat and ensuring uninterrupted electricity supply. It is helping the world transition to a cleaner energy regime, alongside renewables. It is also intensifying the contest for and control of gas-transit routes.

Despite its enduring importance to the global energy system, business and government leaders did not pay much attention to the transit risk until contentious relations between Russia and Ukraine disrupted natural gas flows to Europe in 2006. Russia wants to diversify its flow from relying on Ukraine, while the US, the world's largest gas producer, is increasingly exporting LNG through sea routes mostly controlled by the US navy.

Geostrategic calculations are likely to more profoundly affect gas transit in the future and become a larger part of the decision whether to invest in pipeline transit. Countries that focus too narrowly on market considerations for gas-transit security could become vulnerable to the whims of geopolitics. The possibility of a trade war between the US and China could affect oil and gas as well as the global economy — and not in a good way. Further tensions in the Middle East could erupt and easily affect global prices, sending them shooting back up in the event of supplies being threatened or disrupted.

It is safe to assume that oil company executives have plans in place to activate at a moment's notice should geopolitical factors dictate the necessity. Many parts of the world remain unstable and could erupt into larger conflagrations, as the growth in gas demand increases the geopolitical competition to control resources and transit routes.

Of the many hotspots – Syria, Iran, North Korea, or the South China Sea – the area that causes the most worries is Ukraine, where the existing gas-transit contract between Naftogaz Ukrainy and Gazprom is set to expire at the end of 2019. Russia wants to free itself from depending on Ukraine to send gas by pipeline to Europe and financed and built Nord Stream II and TurkStream-I and II to diversify out of its Ukraine risk. Yet, except for one leg of TurkStream, these options are not likely to be available for early 2020, leaving Russia unable to meet its minimum contractual demands for Europe of 70 % of the take-or-pay level.

Kiev would obviously prefer a new deal that would provide gas supply security, allow it to receive transit fees from Moscow, and retain geopolitical leverage. The two sides began negotiating in 2018 but have made little progress to date. If no deal is reached, Moscow will be forced into a corner.

The geopolitics of gas shape Russia's Ukraine policy. Russia has made steady progress on the "Power of Siberia-I" pipeline to eastern China and the "Power of Siberia-II" to western China. The US-China trade war is an opportunity for Russia to gain access to the world's fastest growing gas market.

Russia's European portfolio is more uncertain than ever. If Nord Stream-II and TurkStream-II come online, Russia will be in prime position. Yet neither project is assured. Nord Stream II continues to face challenging prospects, and while most believe that it will be completed and begin operating, the volumes are up for negotiation. Smartly, European leaders have tried to tie these negotiations to Ukraine, which might constrain Russia from acting too assertively.

International capital available for long-term energy investment is scarce all around the world. Many international banks have largely withdrawn from parts of Africa, Russia, Central Asia and the Middle East in the aftermath of the financial crisis, or because they have become much more selective and demanding in their choice of projects. The need to incentivise private capital flow into clean energy development is greater than ever and will likely become more urgent with time. Turkey has to find ways of unlocking new sources of finance and investment, via the growth of bond, securitisation and equity markets, and potentially by tapping into large funds held by institutional investors, IFIs, insurers, sovereign wealth funds, Islamic finance and companies. Perhaps creating an energy fund to provide seed capital to major energy projects could be considered as one way of enticing further international investors.

## 8.4 Turkish gas market development

In light of these dynamics and the importance of gas in Turkey's energy economy, it is important to reconsider the traditional strategy to provide a secure, affordable, environmentally friendly, and flexible gas supply as well as transit. Turkey’s well-developed natural gas market, early efforts at supply diversification, and close proximity to consumers in Europe have placed it in a favourable position.

The decline in energy prices, topped with the geopolitical tensions flaring up in Eurasia, the Middle East, East Asia and Venezuela, indicates the start of yet another tumultuous time. These developments will likely have a bearing on energy security for both Turkey and the broader energy producing, transiting and consuming regions around it.

Renewable energy has emerged as a vital and indispensable part of the answer. In order to ease the burden of its annual energy bill, Turkey wants to increase the share of renewable and other domestically produced sources in its energy mix. This would hopefully lead to reduction in the volumes of energy imported from abroad. Turkey envisages producing 30% of its electricity needs from renewables by 2030.

Efforts towards greater energy efficiency would also make a significant contribution to reducing the import bill. The integration of nuclear energy into the energy mix (more than 10GW by 2030) is another tool in responding to the growing electricity demand while avoiding dependence on imported fuels. The renewables sector will remain relatively insulated to Turkey's currency woes and import difficulties. This is largely down to the government enabling wind and solar generators to tap into USD-denominated tariffs, in order to offset currency volatility risks.

For the renewables sector, large-scale competitive capacity tenders will replace the feed-in-tariff as the main driver of capacity growth. This will reduce costs for new projects, making wind and solar facilities more attractive to the government. However, the ambitious target for renewables can only be a solution in relatively small provinces - it is impossible to install sufficient wind turbines or solar panels in locations where the bulk of energy is consumed such as in İstanbul.

Nuclear energy is considered to be a “must” for Turkey’s agenda for additional energy and diversification. Non-hydropower renewables energy is likely to grow steadily in importance in the power mix, from 11% in 2018 to 21% by 2027.

Two long-awaited events in the Turkish gas sector point to a more liquid market - the start of deliveries of up to 6 bcm/year of Azeri gas through the newly commissioned TANAP pipeline and the beginning of gas trading on

Turkey's EPIAS exchange. But while both have been expected to herald the further liberalisation of the gas market, there are signs that it could in fact mean its effective “de-liberalisation." This backward move could be the result of a heady combination of political expediency, the volatility of the lira and growing disquiet on the part of Turkey's main gas supplier, Gazprom.

While the lira dropped against the dollar significantly, it was not reflected in the wholesale prices charged by Botas, which is responsible for 81% of imports. While this effective price freeze benefited the government in elections in June 2018, it left the seven private importers, which collectively hold contracts with Gazprom to import 10 bcm/year of gas via the Trans Balkan pipeline, unable to compete. Six of the seven have reportedly failed to meet their take-or-pay commitments with Gazprom and may have been left obliged to pay for gas they have been unable to import. Botas has attempted to alleviate the problem by buying gas from some of the importers.

But this has failed to satisfy Gazprom, which is unhappy with what it sees as the failure of market liberalisation. Gazprom now wants all 10 bcm/year transferred back to Botas, which imported these volumes prior to liberalisation. To that end, Gazprom is trying to persuade the seven to "merge" into a single entity. This would greatly ease the process of transferring responsibility for the 10 bcm/year to Botas ahead of planned commissioning at the end of 2020 of the 15.75 bcm/year TurkStream pipeline.

If successful, the merger and subsequent transfer would effectively spell the end of Turkey's nascent liberalised gas market. De-Liberalisation also threatens to create further problems for operators of Turkey's 22.43GW of gas-fired power plant, which will lose what little gas market competition currently exists and be left dependent on Botas for supplies. But, the almost 50% increase in price for gas-fired power plants may also herald 29% gas price liberalisation as these operators will be free to buy from wherever they want.

Many gas plant operators are believed to be suffering serious financial problems. CCGT operators are praying for a cold winter to boost base-load demand and hoping they can survive to 2020 when the off-take guarantees for a number of large CCGT plant built in the late 1990s time out, freeing up base-load demand. However, this market adjustment will not boost gas demand, which Turkey's gas distributors association GAZBIR estimates will fall by 3.7 % to around 52 bcm this year.

While this may help Ankara's efforts to reduce its trade deficit, it presents a problem for Botas, which has contracted to take a further 6 bcm/year of Azeri gas through the TANAP pipeline, plus a further 14.75 bcm through the soon-to-be-completed TurkStream line. If the transfer of 10 bcm of private contracts goes ahead by mid-2020 Botas will have a contracted commitment of up to 61.2 bcm, not including the spot LNG cargoes it imports for peak shaving and may well be facing take-or-pay problems of its own.

Botaş controls wholesale prices for different categories of gas customers. This restricts the pricing opportunities of businesses that hold natural gas import licenses and contracts. Continued diversification of Botaş' gas contracts not only involves ongoing transfers of contracts to private companies but also supports the movement to cost-reflective pricing. This will enable private importers to operate at a profit and eventually result in the transfer of assets to private entities sufficient to establish a true market pricing of Turkey's gas resources. These are difficult decisions to make, in difficult times.

The government is implementing step-by-step market liberalisation measures, starting with the power sector and moving now to the natural gas sector at a slower pace. Turkey has moved swiftly towards FLNG and has two FLNG projects in operation providing some flexibility, albeit at a high cost. The FLNG projects at Etki and Dörtyol have minimised the over-dependence and opened the country out to further imports from countries as far flung as Trinidad & Tobago, Norway and Equatorial Guinea. Turkey's FLNG projects are an example of how both the public and private sectors can, in record time, engage to help realise strategic objectives.

A physical gas hub must have enough storage to provide supply liquidity and common carrier pipelines to facilitate physical sales and purchases of its gas. The addition of new storage facilities has gone a considerable way to increasing Turkey's limited storage capacity, now increasing to at least 20% of its annual consumption in a bid to avoid supply disruptions and emerge as a natural gas trade hub. If the market reforms progress and convergence of geo-strategic and energy policies is achieved, Turkey may not be far from achieving its goal to become a trading hub for natural gas.

## 8.5 Becoming a regional energy hub?

It is a national obsession. Talking about what the real "hub" means and when Turkey can progress towards that goal are subjects not taken lightly. Turkish leaders and experts use this terminology in a relaxed and casual manner without knowing what it really means. An energy hub is a multi-carrier energy system consisting of multiple energy conversion, storage and/or network technologies, and characterised by some degree of local control. Combined with energy storage, conversions between different energy carriers in an energy hub enables greater flexibility. As such, hubs are also useful for enabling the integration of intermittent renewable energy sources such as solar and wind with natural gas and oil.

For nearly a decade, Turkey has sought to exercise influence based on its strategic geopolitical position between an energy-hungry Europe and energy-rich regions to the north, east and south. Currently, Turkey has the strongest position to become the gas hub in the region, given the volume of its national gas market and its projected growth, as well as the level of infrastructure development and six entry points for pipeline gas and LNG. With potential pipelines from Iraq's KRG, TANAP, TurkStream and the East Med pipeline, there might be at least eight entry points in the future. Once TAP is completed, Turkey will have at least one Interconnector (and one exit point) to Greece.

Globally, two types of hubs for natural gas trading have emerged: physical and virtual. Currently the EU prefers to continue to integrate its natural gas markets through the establishment of virtual (regional) trading hubs. This is a pragmatic approach, since it builds on the existing arrangements of national TSOs and regulators (rather than creating one overarching European regulator) and an infrastructure built to facilitate long-term import contracts with national balancing and limited interconnections.

Turkey could either become a physical gas-trading hub with import and export pipelines, connected to other hubs via Interconnectors, or a commercial hub with bilateral and broker-based trading. Yet, being a regional energy hub means not just having intersecting pipelines. It requires sufficient volumes of supply and demand, physical infrastructure, an adequate legal and institutional framework to assure suppliers and consumers, political stability and financial institutions. Whether the Turkish goal of becoming an energy bridge along east-west and north-south axes (and serving not only as a transit country, but also as an aggregator and centre of trade) is a realistic one remains largely unanswered.

Russia's strategy in the Southern Corridor issue is based on two pillars. The first is to prevent cheaper Central Asian gas accessing Europe, to protect the virtual Russian monopoly in the European market and its arbiter role as buyer and shipper of Central Asian gas. The second pillar is reducing Russia's dependence on Ukraine as its main gas transit country by promoting a new reliable transit country: Turkey. That is why, in addition to the current pipeline infrastructure, which is not yet at full capacity, Russia is promoting the TurkStream-I and -II pipeline projects to frustrate European southern corridor initiatives. Turkey does not dedicate all its capabilities exclusively to the EU backed-gas pipeline projects.

Azerbaijan is a critical energy partner for Turkey, irrespective of its linguistic, ethnic and other affinities, and has decided to invest heavily in Turkey. It is now the largest FDI provider. The most important project is the multi-billion-dollar TANAP. Azerbaijan has proven gas reserves of more than 3Tcm. Once TANAP becomes operational, Europe and Turkey will be relieved to some extent from their reliance on Russian gas. About $45 bn will be invested in the resource development and pipeline, which will extend from Azerbaijan to Italy, traversing 21 Turkish provinces.

The world's second largest natural gas reserves holder, Iran, can well be connected to Europe via Turkey when sanctions are fully removed, and the Iranian investment regime is made friendly for western IOCs to develop South

Pars and other attractive acreage. Iran, which supplies Turkey with 17% of its gas imports, can be considered as an additional gas supplier, especially if prices can be negotiated downwards. Iran has so far dismissed Turkish demands to reduce the price of gas under the current agreement and insists on selling more natural gas to its energy-hungry neighbour under a new agreement. Turkey could double the amount of natural gas it imports from Iran (10 bcm) if the two countries could agree on price. Independent feasibility studies show that, if sanctions were to be eased and investments started soon, Iran could supply up to 20 bcm/year of gas to Turkey and Europe in the next decade.

Turkey may have to import natural gas also from its southern neighbour, Iraq's Kurdish region, where Russia's biggest oil company, Rosneft, has become a key player in energy transport infrastructure and upstream oil and gas investments. Rosneft has boosted its investment in the Kurdish region to $3.5 bn. The move appears to be part of a strategy by President Vladimir Putin to enhance Moscow's Middle Eastern political and economic influence, which was weakened by the collapse of the Soviet Union. Rosneft's investment comes amid a crisis in Kurdistan's relations with the central government in Baghdad following the region's independence referendum in 2018, which angered neighbours Iran and Turkey. There is a need for Ankara to pursue a more proactive strategy towards Iraq and its Kurdish region as an investor, trader, transit and security provider.

Sooner or later, Israeli gas will find its way to Turkey and via TANAP to Europe, if the private sector players take the lead and governments stay in the background. Actions to resolve long-standing issues in the Eastern Mediterranean would also be attractive to investors and to potential customers in Europe who may be concerned about a range of actions, some recent and some decades-old, that work against the stability, flexibility, and liquidity that would support a robust hub.

The EU understands Turkey's importance as a transit country but is weary of its volatile internal politics and those of its neighbours, notably in the Caucasus, Ukraine, Iraq, and Syria. The country's geography is suitable for gas transit to Europe, but the problem remains that the EU wants to implement energy *acquis* in supplier and transit countries via the Energy Community.

Turkey's current policies represent a good start in a long process of reforms aimed at helping generate capital, increase market transparency for energy buyers and sellers, and help promote wholesale and retail price competition. The advantages of these changes are manifold. Competitive markets typically produce cost-effective capital formation and a lower cost of retail energy services. Under state control, energy prices do not necessarily reflect costs but, in the long run, costs are more important since subsidised energy prices are costly to sustain and can lead to reduced economic growth.

Turkey has made progress with establishing a natural gas hub, but further work needs to be done. During the next round of pipeline negotiations, perhaps the most important action Turkey could take is the elimination of destination clauses in its gas contracts. An added benefit of this would be increased progress towards cost-reflective pricing, a benefit for both Turkish energy consumers and Turkey.

Market liberalisation would mean the end of existing policies to cross-subsidise natural gas prices differently among power generators, industry, and retail customers. In general, depending on the trend line of marginal energy costs, retail energy prices could rise or fall after market liberalisation. However, with Turkey's recent low costs and current low prices, retail prices may initially rise as subsidies are reduced or removed.

Nonetheless, cost-reflective energy pricing is the best way to increase national economic performance and also promote energy efficiency. With cost-reflective prices, other ways can be devised to support needy consumers while achieving national economic benefits and environmental improvement.

All of these factors will likely cause Botaş to move to cost-reflective pricing, as seen in its 6 August 2018 announcement of price increases, although residential and industrial tariffs remained 20% to 35% below Botaş' weighted average cost of natural gas (underscoring the need for additional and significant reforms).

The establishment of a natural gas hub in Turkey can unlock significant benefits that would support the country's economic, environmental, and security goals. Market changes and investments could be the most effective way to reduce natural gas pricing uncertainty and volatility, increase the desirability of natural gas as a key energy source for Turkey, and potentially lead to the eventual establishment of a hub. The creation of a natural gas hub would effectively de-link natural gas prices from oil prices, removing a significant source of gas price volatility that has little to do with the fundamentals of natural gas markets.

A Turkish natural gas hub would enhance Turkey's energy security by reducing the vulnerabilities associated with current gas imports through increased gas storage capacity, greater supply diversity, and the capacity to import large volumes of spot LNG as needed. In addition, a Turkish hub would effectively make Turkey a natural gas exporter regardless of its indigenous production levels, enabling it to directly respond to demand from connected European purchasers, and to add to overall global supplies. This may result in better trade agreements and increased investment in the Turkish economy.

Natural gas as a component of Turkey's energy mix could help firm variable renewable generation (i.e., a non-dispatchable renewable energy source like wind or solar) and offer a relatively low capital-cost alternative to retiring coal plants that cannot be affordably retrofitted with carbon capture, storage and utilisation technologies. Natural gas can also play an important role in reducing Turkey's power sector greenhouse gas emissions, especially if competitive markets allocate power sector investments.

## 8.6 Policy messages for governments and businesses

Overall, Turkey needs to make best use of the new dynamics in regional and global gas markets, as well as the expiry of the existing long-term contracts to enhance its competitive economy, supply security and regional hub ambitions.

Establishing a robust Turkish natural gas transit regime and eventually a regional hub would require significant infrastructure investments, changes to the current natural gas market, new transparent market mechanisms, resolution of underlying geopolitical tensions that deter investors, development of additional sources of supply and potential customers and suppliers. The gas hub vision requires sufficient spot gas to be traded to form a reliable price index - a move from oil indexation to hub price index even in long-term contracts. The "gas-to-gas competition" with LNG coming into picture would reduce prices to the benefit of consumers.

In the new era, Turkey should end take-or-pay deals or reduce its commitment for long-term contracts. The new global energy outlook pushing producers to offer discounts in order to protect market share might help in this regard. Both Ankara and Moscow see energy flows as a major advantage for their respective geopolitical positions, most prominently in relations with the EU, and have been taken by surprise by the disappearance of this advantage in the course of the fast-moving global revolution in energy affairs. Turkey wants Russia to give Ankara more flexibility on the size of its purchases, the price Turkey pays, and the right to re-sell gas purchased above Turkish domestic needs on third party markets.

However, the present contracts include a destination clause and do not provide any re-export rights to Turkey. Without such actions, destination clauses for large suppliers will restrict needed supply liquidity. The energy relationship is unbalanced in favour of Russia and can be used for Moscow's geopolitical jockeying in Syria, northern Iraq (where Rosneft is gaining strength), the Caspian and the Black Sea. There is a need to re-establish the balance of interest between Ankara and Moscow. Eliminating such clauses serves Turkey's short and mid-term interests. Botaş could secure contracts sufficient to meet domestic gas requirements, while also establishing Turkey as a natural gas exporter. Of course, Gazprom will not welcome Turkish competition to its pipelines, destined to supply gas to Europe. Nonetheless, their markets are likely to be different and, if Turkey becomes a free-market natural gas trading centre, Gazprom could benefit from the likelihood of higher export volumes.

The Turkish government needs to continue, as part of further liberalisation, phasing out subsidies that distort the level-playing field in the highly attractive and rapidly growing gas market. The long-standing commitment to unbundle Botas's transport and wholesale businesses and create a commercial energy exchange should be reactivated in a bid to provide a predictable pricing mechanism for banks and financial institutions. This would help to build confidence among foreign energy investors.

As a major energy consumer and transit country, Turkey must create its own "energy champions" that will be able to play the game by international rules in oil, gas, coal and renewable energy in such a way so as to mobilize the private sector with its dynamism and international resources. Turkey must take steps to encourage Turkish energy companies to invest abroad in equity oil, gas, coal, hydro, power plants, and pipelines, ports and oil tankers. Also, substantial FDI and finance inflows into the energy sector are needed - around $120 bn over the next decade, more than double the total amount invested in the last decade.

Turkey is not unique among countries which heavily depend on imported sources of energy and struggle to achieve lesser reliance and greater diversification of sources and fuels of energy. Hence, there is much to learn from the experiences of other energy-hungry nations such as Korea, China and Japan on how to achieve sustainable energy security.

Turkey's geopolitics and energy requirements have to be in harmony and complementary with one another. Otherwise, its energy supply security and regional hub aspiration would be at risk. Resource-holders such as Russia, Iran, Iraq, Caspian and East Mediterranean nations as well as the EU, the main consumer, are of prime importance in this regard. One way or another, the US always plays a role in Turkey's foreign energy strategy because of its influence and its newly acquired position as the world's largest oil and gas producer. China's BRI will also figure prominently in the future.

Energy efficiency improvements are the best energy security investment. Turkey should be able to adopt a specific target to reduce the energy intensity of its economy by at least 2.5%/year. It should also work towards a retooling of its industry progressively to compete in a low-carbon economy, moving away from energy-intensive and "dirty" sectors, such as iron-steel mills, cement, fertiliser and aluminum. The other prerequisite is commitment to maximising its technological expertise towards a "smarter" and "cleaner" economy, aiming at becoming a pioneer, rather than a follower, in solar, geothermal and hydro energy technologies.

Energy is a vital part of the EU's increasingly strained relationship with Ankara. Turkey's becoming a major energy transit country or one day a regional hub could help advance Turkey's desire for a more balanced, mutually rewarding partnership with the EU, independently of its long standing and controversial accession saga.

A new natural gas initiative could represent a fresh effort to rebuild the much-needed trust, a fundamental prerequisite not only for energy co-operation between the two players, but also for overall EU-Turkey relations. Refocusing bilateral energy co-operation away from gas and electricity trading, more towards renewable and nuclear energy, energy efficiency, and carbon markets, would be more impactful and strategic for both the EU and Turkey. For the EU, it would provide an opportunity to put its aspirations to leadership in sustainable energy into practice, while opening up new commercial opportunities. For Turkey, it would enhance both climate and environmental performance, while reducing the energy import bill and energy dependency on Russia.

The recent major gas discoveries in the Eastern Mediterranean (offshore Egypt, Israel and Cyprus) may also be sourced to supply the Turkish market and transported beyond to Europe. However, the underlying geopolitical frictions would need to be cleared. That would require the resolution of the decades old Cyprus conflict to mutual satisfaction as well as the re-establishment of trust and the strategic partnership with Israel, Egypt and Turkey.

Turkmenistan's willingness to supply 20-30 bcm/year of gas to Europe is of great importance to Turkey but is not realistic in the foreseeable future. As a matter of fact, Turkmen (and probably Kazakh) gas transported via the TANAP pipeline could possibly make the project more cost-effective, financially viable and geopolitically sound. However, a major problem against the project is the unresolved legal status of the Caspian Sea, and hence political constraints imposed on the project by Russia and Iran, which may not allow price competitive Caspian gas to reach their market strongholds.

No matter what the political or economic problems are, Turkey must continue maintaining its credibility as a country over which energy flows will not be disrupted. It has become almost commonplace for Turkish government leaders to assert that energy transit to Europe via Turkey is not only an economic project but also a geopolitical project vis-à-vis Europe and producing regions around it. Any misuse of Turkey's energy transit role for political leverage on the EU could diminish its value. Overplaying Ankara's hand could, moreover, cast doubt on its reliability as a transit country from a business perspective.

Turkey's energy policy cannot be formulated and treated in isolation from a wider government vision. It is closely related to taxation, environment, competition, industry and investment, trade policies, foreign policy and security strategy, and needs to be tackled in an integrated way. If Turkey is serious about reaching its strategic goals in all sectors, energy has to play a pivotal role in driving its reform and growth engine. An integrated vision, effective project leaders and teams, and investment in human capital and resources are essential ingredients. The government cannot develop and implement such a vision by itself. Most actions require a timeframe beyond the life of a government. Therefore, a non-partisan (to the extent possible) approach should embrace the opposition, private sector, civil society and international organisations, based on shared goals. With the right policies, institutions and leadership, Turkey could well sit as a member on the management board of the new world energy order by 2030.

Chapter 9

# The potential of Iraqi gas exports to Turkey and Europe

# 9. The Potential of Iraqi Gas Exports to Turkey and Europe

by John Roberts

## 9.1 Introduction

Iraq has plentiful gas resources but the problems of both developing and exporting them make it a tough task to transport gas to Turkish and European markets.

Much depends on political and commercial developments in the autonomous Kurdistan region of Iraq (KRI) and, in particular, on the activities of two companies engaged in developing the KRI's energy resources: Turkey's Genel Energy and Russia's Rosneft.

There are other prospects and other companies that may well, in the long run, play significant roles, not least as security returns to the bulk of Iraq directly controlled by the Federal Government in Baghdad. But while Federal Iraq holds significant gas reserves, with some fields previously identified as potential sources of exports towards Turkey, Baghdad's principal requirement at present is to utilize its own gas for domestic purposes, thus easing its reliance on gas imported from Iran.

The KRI, however, is in a very different position. In terms of both its resource base and its ability to develop those resources, it could – at least in theory – look to a relatively rapid development of gas for export. In 2015, the Ministry of Natural Resources (MNR) of the Kurdistan Regional Government (KRG) estimated that the KRI possessed some 25 trillion cubic feet (tcf) (708 billion cubic metres - bcm) of proven gas reserves, while estimates based on company reports yield a figure of 39.7 tcf (1,124 bcm) in discovered reserves and contingent resources. These are markedly different levels from the 177 tcf (5,012 bcm) that the KRI is commonly cited as possessing. The issue of KRI gas reserves is highly complex. The value of 177 tcf is based on the MNR's formulation that the KRI possesses 25 tcf of proven reserves and also between 99 and 198 tcf of undiscovered gas resources. But even on the basis of 25 tcf of proven reserves and/or company estimates of 39.7 tcf, the KRI has plenty of gas both for its own use and for export (Qamar Energy, 2011).

However, export-led development requires various political issues to be resolved, notably tensions with Turkey that have arisen as a result of the KRG's decision in September 2017 to hold a referendum on Kurdish independence and because Turkey's most important regional concerns are the suppression of Kurdish militants inside Turkey and Syrian Kurdish forces operating immediately south of the Turkey-Syrian border.

On the commercial side, Genel has already carried out considerable work at its fields at Miran and Bina Bawi in the KRI. But it has run into financial trouble and it has proved unable to implement plans for gas exports to Turkey that were envisaged in a joint Turkish-Kurdish declaration in 2013. On the other hand, Rosneft is now highly active in the KRI, and it has both the diplomatic muscle and the financial resources to be able to break the political deadlocks hampering Kurdish gas exports and to ensure construction of the infrastructure necessary to carry the gas to foreign markets.

Turkey will almost certainly be a major market, simply because of its proximity to the Kurdish gas fields and, in particular, because supplies from the KRI would help gasify neighbouring regions of southwestern Turkey, which are among the least gasified parts of the country.

In principle, should Kurdish gas reach Turkey, then it is possible to envisage it contributing to European supplies by means of the Southern Gas Corridor (SGC). However, such thoughts are probably premature at this stage, although it is worth noting that there has been some thinking along these lines. Indeed, virtually the last action of the ill-fated Nabucco consortium was an environmental impact assessment of the most likely route to carry Iraqi gas to a junction on the route laid out for Nabucco and now operational as part of the TANAP system.

In the immediate future, should the KRI begin to export gas to Turkey, its most likely contribution to European supplies would be to replace gas imported from Azerbaijan and Iran to Southeast Turkey, thus freeing up such supplies – particularly those from Azerbaijan – for delivery elsewhere, possibly including customers beyond Turkey that could be reached via the SGC.

So far, there have been three distinct phases concerning the KRG's approach to gas exports.

## 9.2 The First Phase

The first, from 2008-2011, revolved around the prospect of supplying gas from the first fields to be developed, Khor Mor and Chamchamal, into the proposed Nabucco system intended to carry gas from Azerbaijan and other regional sources near Turkey to Europe. But by 2011, the classic Nabucco concept had to be abandoned because Azerbaijan's SOCAR began to push for its own dedicated pipeline across Turkey. This meant that the KRI authorities had to re-think their approach to gas connections across the border and also to bear in mind the changing dynamics of prospective gas output from Miran and other new gas fields. This prompted substantial re-consideration of both near-term connections into the existing BOTAŞ-operated system in Turkey and the long-term construction of dedicated systems.

## 9.3 The Second Phase

The second phase began in 2012, when it became clear that Nabucco had been superseded by the Trans Anatolian Pipeline (TANAP) project, but still well before real clarity about the form the totality of the SGC would take was achieved when various final investment decisions were taken in late 2013. In December 2012 Genel's CEO, former BP chief Tony Hayward, said that "by the end of the decade it is reasonable to suppose that northern Iraq will be supplying Turkey with some 10 bcm of gas". As to whether that gas might then travel further afield, a BOTAŞ official said a couple of months earlier that, in the long term, "of course, we'd love to see Iraqi gas in the TANAP."

Then came the signing in November 2013 of what seemed at the time to be a groundbreaking set of agreements between the KRG and the Government of Turkey. These agreements primarily concerned oil, but they did include a specific commitment to develop the gas pipeline infrastructure required to enable the KRI to export as much as 20 bcm/year, with deliveries expected to start in 2017. They also included participation by a state-backed enterprise, the Turkish Energy Company, in 13 exploration blocks in the KRI.

At that time, KRG and Turkish officials were discussing an extension into Turkey of an existing gas line connecting the gas fields at Khor Mor with Dohuk, in the northeast of the KRI. At the same time, Turkey's Genel Energy was working with the KRG authorities on development of a quite separate project for a new gas line to carry output from fields operated by a number of companies, including its own Miran concession. However, it turned out that – for gas – only the second of these projects was potentially viable as the KRG and various oil companies working in the KRI had other plans for the gas line to Dohuk and its extension to Turkey. They would use it for oil. In due course, the Dohuk line was indeed converted for use to oil and is currently a feeder line into the KRI's principal export system, the Kirkuk-Ceyhan oil pipeline.

For Genel, a fundamental driver for development of Miran was – and is – the ability to access attractive gas markets, with Turkey as its main focus. Genel argued that gas from the KRI, with Miran at the forefront, would enable the Turkish Government both to meet its demand requirements and to achieve its stated goal of diversifying sources of supply. At this stage, Genel considered that Miran possessed some 12.3 tcf (0.35 tcm) of gas-in-place, with significant growth expected as further appraisal wells were spudded.

Progress was slower than expected, but Genel's optimism remained undimmed. In November 2015, KRG Minister of Natural Resources Ashti Hawrami and Genel Chairman Tony Hayward jointly declared the KRI should be able to start delivering up to 10 bcm/year to Turkey in approximately 2018 or 2019 and double that amount in the early 2020s. This was swiftly followed by a tender in early 2016, organized by Turkey's state pipeline company, BOTAŞ, for construction of a 185-km, 20 bcm/year capacity pipeline from Sirnak, in southern Turkey near the Iraqi-Turkish border, to a connection with the Turkish grid at Mardin, a key component of the necessary export infrastructure. But the tender appears to have yielded no positive outcome. It was re-tendered in April 2016, with market reports saying subsequently that it had been won by a Turkish company, Vemak. But although these reports said that Vemak had begun work on the project on 4 August 2016, there were no subsequent reports to confirm actual project implementation while sources contacted by the author said in late 2018 that they feared there has been no real development of this project in the last year or so.

The stalling of progress on such a key requirement for gas exports from the KRI to Turkey effectively brought the second phase of gas development to an end, not least since it coincided with three adverse trends impacting KRI energy development in general and gas development in particular. The first trend was commercial; the fall in energy prices. The second concerned security; the civil war in Syria, particularly Turkey's concerns regarding the war against ISIS. The third was political; the steady drive by the KRG to break an internal political impasse by holding a referendum on whether Iraqi Kurdistan should become an independent state.

### ***The Energy Price Issue***

In 2014, energy prices fell considerably and by 2016 this had created a very tough atmosphere for gas investments. In December 2013, the month in which the biggest SGC FIDs were taken, the price of gas at the German border, one of the best guides to European gas prices, ranged from $10.96 to $10.99/mmbtu (million British thermal units). At the end of 2014, it was still $10.45 but a rapid slide then saw it slip to $5.81 at the end of 2015 before hitting its nadir of $3.96 at the end of September 2016. The recovery since then has only been mildly encouraging, with the border price reaching $5.16 at the end of 2016 and then rising by around 12% over the following two years to the end of 2018.

### ***The War in Syria***

The rise of ISIS in Syria prompted increasing concern in Ankara. Some of the most effective forces confronting ISIS with Western support were – and are – the Syrian Kurdish fighters known as the YPG. However, the government of Turkey regards the YPG as an extension of the PKK Kurdish militants within Turkey itself and Turkish security forces have been involved in a series of clashes, described as a war by some senior Turkish officers, with PKK fighters and presumed supporters since a ceasefire collapsed in July 2015. The resulting Turkish policy of war against the PKK and repeated threats of war against the YPG, has naturally strained relations between Ankara and Erbil, even though the KRI's own Pesh Merga fighters have largely kept out of the war in Syria.

Throughout January and February 2019, as the YPG were leading the campaign to capture the last remains scraps of territory held by ISIS in Syria, Turkish President Recep Tayyip Erdogan repeatedly warned that unless the YPG removed itself from areas along the 911-km Turkish-Syrian border, then Turkish troops would force them out. If there were to be such a war, two potential consequences would have to be borne in mind. The first is that the war with the PKK inside Turkey might intensify, threatening the oil pipeline that carries KRI oil exports to market and increasing the obstacles to gas line development from the KRI to Turkey. The second is that the KRG would feel extremely uncomfortable in pursuing business as usual with Turkey. And while Erbil can bring little or no pressure to bear on Ankara in this regard, it can consider whether striking some kind of alternative deal with Baghdad would offer a better long-term option.

***The Kurdish Referendum***

On 25 September 2017, the KRG held a long promised, but ill-timed, independence referendum. The Federal Government in Baghdad, regaining strength after its own war with ISIL, warned against such a move, as did the Turkish Government. The KRG's western friends, the governments of a cluster of countries whose companies produce the oil on which KRI revenues depend, added their own warnings. But internal Kurdish politics triumphed, and the referendum was called and held. It was to prove a psychological success for the KRG, but an unmitigated military and economic disaster. Some 92.7% of the three million voters who participated voted for independence, but the motion on which they voted not only called for an independent Kurdish state to be established within the previously agreed boundaries of the KRI but also in adjoining territories controlled by the KRG, notably the disputed city of Kirkuk.

Both Ankara and Baghdad responded immediately; one with words and one with arms. On 26 September, President Erdogan visited the Habur border crossing to witness joint military exercises with Federal Iraqi troops. He warned that if the Kurds declared independence then they "will be left in the lurch when we start imposing our sanctions." He added: "It will be over when we close the oil taps, all (their) revenues will vanish, and they will not be able to find food when our trucks stop going to northern Iraq." For the KRG, the bottom line is very clear indeed: The Turkish Government cannot tolerate an independent Kurdish State because of the implications for its own war against Kurdish separatists in Turkey and their associates in Syria.

Baghdad's response took a little longer but was even more emphatic. It dispatched troops north and within a month Federal Iraqi forces had wrested back control of much of the Kirkuk region, including most of the giant Kirkuk oilfield. Overnight, the KRG's oil revenues, on which it relies heavily for its income, collapsed. In the first half of 2018, KRG net revenues from oil exports (a figure that allows for payments to companies, including settlement of previous debts) totalled just $648.6 million. In the comparable period of 2017, they had reached $3,328.2 million, with figures for the third quarter of the year showing even higher monthly rates.

## 9.4 The Third Phase

As of early 2019, these three factors have combined to pose continuing problems for gas development in the KRI, particularly for Genel Energy. Thus, the third phase of KRG gas development, which might be deemed to have started at the time of the referendum, is taking place in a far less promising atmosphere than previous phases. As a result, Genel currently appears to be focusing more on its oil operations in the KRI than on gas.

Yet there are grounds for thinking that at some stage Genel will be able to develop Miran and Nina Bawi. As of 2016, these fields were considered by Genel to hold 320 bcm of gas in place (technically, gross mean raw gas) which should be able to yield around 240 bcm of gas for actual sale (technically, gross mean sales gas). But in January 2018, Genel disclosed that fresh studies had “confirmed a c.45% uplift to gross 2C raw gas resources to 14.8 tcf (419 bcm)”.

Equally important, the Genel statement added: “The upstream part of the project has been materially de-risked, with 1C volumes more than sufficient for the gas volumes required under the gas lifting agreement.” In addition, “further reservoir engineering has demonstrated the viability of high-rate gas wells, which in turn more than halves the number of wells required to produce the volumes under the gas lifting agreement, materially reducing the overall cost of the project.”

This is crucial; development of gas for export is expensive. As of 2016, when it was intensely focusing on development of its gas resources in the KRI, Genel was estimating the costs of developing Miran and Bina Bawi at $5.4 billion. This comprised $1billion for Genel itself to start raw gas production; $2.5 billion for a midstream company to develop processing facilities to convert the raw gas into actual sales gas; and a further $1.9 billion in upstream expenditure throughout the life of the field. Overall production costs would be $5.50/boe, or less than $1/mscf.

Genel considered the Kurdish domestic market could take around 300-500 mmcf/d (about 3.1 to 5.2 bcm/year) and that the commercial structure it had developed for selling the fields’ output meant that the identity of the actual end user did not matter. The commercial arrangements reached with the KRG provided for the KRG to pay Genel a delivery rate for raw gas of $1.20/mcf, while the price for raw gas required for Turkish exports would be guaranteed by Turkey and the KRG under their November 2013 general sales agreement (GSA). The principle was that Genel, which was both the operator and 100%

owner of Miran and Bina Bawi, would be wholly and solely responsible for developing the upstream facilities. It would then sell the raw gas produced from the fields to the KRG, which would then pipe the raw gas to a company set up to handle midstream processing, with the fees for this work already covered in the 2013 GSA. The raw gas dispatched for processing would then return as sales gas to the KRG, which would be responsible for selling it on the international and domestic markets.

When this development will actually get under way remains in doubt. The project was originally intended to raise output very rapidly, so that the KRI would be in a position to export 10 bcm/year in 2020, primarily from Miran and Bina Bawi. The estimated costs were comparatively modest in terms of comparable projects elsewhere, but they still required substantial investments to be made in a territory whose long-term status remained uncertain. In effect, costs would come in at around a quarter of the upstream cost of the giant Shah Deniz Phase Two project, while production would be approaching half the level of SD2 output.

Political issues, notably the vexed question of how to get the gas across the border to Turkey, would also prove to be extremely complex. In February 2017, seven months before the referendum, Genel was optimistic. The company stated: "With the production sharing contract and gas lifting agreement (GLA) terms formally confirmed, Genel will now be able to progress the project. The company remains committed to developing these large scale, low-cost, onshore gas fields, which will form the cornerstone of gas exports to Turkey under the 2013 KRG-Turkey gas sales agreement". A month later, Genel declared: "Through its Miran and Bina Bawi gas fields, Genel is set to be a cornerstone provider of gas to Turkey under the KRI-Turkey Gas Sales Agreement."

Since then, however, delay has been the most notable characteristic. In January 2018, Genel requested, and secured a 12-month extension to the deadline for meeting the conditions of the gas lifting agreements for the two fields. By this time, the company's financial position had become more constrained in the wake of setbacks at its Taq Taq oilfield in the KRI. In January 2019 it secured a further extension for the Bina Bawi field to 30 April 2019 and for Miran to 31 May 2019. A statement in May 2018 exemplified a change in attitude, with its stress on opportunity rather than concrete planning: "Bina Bawi and Miran retain transformational potential, both in terms of gas and oil. The upstream part of the gas project has been materially de-risked and light oil at Bina Bawi offers an exciting opportunity, the progression of which is a key focus." In January 2019, the company issued another cautious statement that said: "Field development plans for both Bina Bawi and Miran oil and gas are under discussion with the KRG, and may entail a phased development approach in order to reduce initial capital expenditure and achieve the earliest date for first gas."

Genel's gas lifting agreement with the KRG specifically provides for the execution of final agreements on both the midstream gas processing facilities and pipeline transportation. Genel only envisaged taking a modest 10% stake in the company to be set up for the $2.5 billion midstream development. But although it appeared at one stage that Turkish backing for this might be forthcoming, nothing actually materialized.

***Enter Rosneft***

This is where Rosneft comes in. The disaster of the Kurdish referendum could well have led to the collapse of the KRG's finances. The fact that it did not was largely due to a bail out from an unexpected source: the state-backed Russian oil company, Rosneft. The KRG signed a cooperation agreement covering upstream investment, infrastructure, logistics, and trading with Rosneft on February 2017 and then expanded it in June, with the two sides agreeing in principle on a number of PSAs – eventually they settled on five – and "on monetization of the export oil pipeline in Iraqi Kurdistan."

For gas, the crucial date was 18 September 2017, just three days after the KRI's parliament approved holding the independence referendum, and exactly a week before the referendum itself. On that day, the Russian company announced that it had negotiated with the KRG for Rosneft "to participate in the project on funding of the construction project of Kurdistan Region's natural gas pipeline infrastructure."

The statement added:

"It is expected that a separate agreement under this project will be finalized by year-end. The Kurdistan Region gas pipeline will not only supply natural gas to the power plants and domestic factories throughout the region, but also enable the export of substantial fuel volume to Turkey and European market in the coming years. The investment in the project will be under a BOOT arrangement, to be recovered through tariff charges and an agreed rate of return basis. The pipeline capacity is expected to handle up to 30 bcma for gas export, in addition to facilitating gas supply to the key domestic users. Rosneft and Kurdistan Regional Government are negotiating implementation of the project for construction of gas pipeline system on a fast track basis. Commissioning of the pipeline and first domestic supplies are planned for 2019 and export supplies – 2020."

No details were given concerning the actual route that the line would take, but Reuters reported that the cost of the line and associated infrastructure would be around $1billion.

One month later, on 18 October, Rosneft signed the documents required to give force to its five PSAs, in which it would have an 80% stake and for which it would pay around$ 400 million. The next day it secured a 60% stake in the pipeline that carries KRI oil exports to a junction on the Turkish border with the Kirkuk-Ceyhan line. It was the cash paid for these agreements that saved Kurdistan from bankruptcy following the catastrophic reduction of oil exports in the wake of the referendum. By the end of 2017, according to subsequent reports, Rosneft had transferred no less than $2.1 billion to the KRG, effectively valuing its contracts in the KRI at well over $3 billion.

In May 2018, Rosneft announced that it had signed a further agreement with the KRG in which it agreed to study “how to participate in the integrated gas business value chain in the region in order to extract maximum efficiency from investments and operations in such areas as exploration and production, transportation and trading with especial attention given to partnership and project (third party) financing options.” The agreement provided for Rosneft and the KRG to “elaborate an integral plan to progress the gas business within the Kurdish Region of Iraq” and added that “one step in this plan is the conduct of a pre-FEED of Iraqi Kurdistan's gas pipeline construction and operation.” The Rosneft statement concluded by saying that “following the outcomes of the integral development plan in terms of the attractiveness and efficiency of the options, Rosneft will decide on how to participate in the regional gas business.”

This remains the critical question. Clearly, the KRG’s intention is that Rosneft will handle the financing and construction of an export line. But since the May 2018 statement, Rosneft has been strangely quiet about its activities in the KRI. There is no indication as to whether any progress has been made concerning the pre-FEED for the gas pipeline and, in particular, whether Rosneft might also seek to pursue a role in regional gas business by taking a stake in the all-important midstream company required to get the Genel’s Miran and Bina Bawi fields ready for export operations, since these remain the best prospects for sourcing gas exports.

### ***The Nabucco EIA***

In terms of what is required to build the actual infrastructure, considerable work has already been done. The last formal statement by Nabucco International before it effectively shelved its classic Nabucco plan in favour of the abbreviated Nabucco West project was the presentation to the Turkish authorities on 12 April 2012 of an environmental impact assessment for a prospective large capacity link to ensure gas from Iraq could enter the Nabucco system. This concerned a proposed 733-km leg that would have carried Kurdish gas from Turkey’s border with the KRI near Silopi to a junction with the Nabucco entry line from the Caucasus at Sivas. TANAP, which largely follows the main route mapped out by the Nabucco team, runs by Sivas. In addition, the BOTAŞ tenders for the proposed 20 bcm/y pipeline from Sirnak to Mardin will have yielded useful studies for Rosneft to draw on since Sirnak is just 31 kms from Silopi and much of the planned 185-km route effectively duplicates the easternmost stretch of Nabucco's proposed KRI link.

However, the most important element in considering the question of Kurdish gas entering the SGC is that of the volume of gas reaching Turkey. It would really have to be a quite considerable magnitude, of around 15-20 bcm/year or so, to justify the cost of building the connection to Sivas. It is far more likely that, if there is a real revival of plans for a cross-border gas pipeline to Turkey, it will carry less gas than this, and that the gas will be used for the Turkish market.

Yet this might still have an impact on the SGC, since it would be quite likely that, under such circumstances, the gas from the KRI would be used in place of gas imported from other sources, notably Azerbaijan. Since 2001, Turkey has been importing up to 6.6 bcm/year of gas from the first phase of Azerbaijan's giant Shah Deniz field (SD1). But this contract is due to expire in April 2021. If comparable volumes can be imported from the KRI by this time, it is possible that the SD1 contract will not be renewed, freeing up 6.6 bcm/year of Azerbaijani exports for delivery elsewhere, notably to customers beyond Turkey.

As of early 2019, this would seem to be the most likely way that Kurdish gas could contribute to SGC development.

***The need for Baghdad's approval***

The weaknesses in all such plans are essentially political. Strained relations between Ankara and Erbil comprise one such element, so too does the strained relationship between Erbil and Baghdad. It has long been the case that consideration of any cross-border pipeline from the KRI to Turkey would have to address the issue of whether Baghdad's approval would be required. The issue was fudged for the oil pipeline connections into the Kirkuk-Ceyhan line, not least because of the relative weakness of the Federal Iraqi Government at that time. As for gas, official Turkish attitudes have wavered. In October 2010 Turkish Energy Minister Taner Yildiz stated emphatically that there was still one major obstacle to pipeline gas reaching Turkey from northern Iraq: "Northern Iraq and the central government should first of all have some kind of agreement," Yildiz said (Platts, 2010).

But when Turkey and the KRG signed their energy agreements in November 2013, Ankara appeared to have accepted the KRG argument that new export lines could be developed without Baghdad's approval. This did indeed seem possible. Ankara was already floating the idea that a Turkish conglomerate, representing both public and private sector interests, might be established to invest in both KRI oil and gas resources and in the infrastructure required to carry them to Turkey. As one prominent western investor in the KRI, Chevron's Ian MacDonald, said in December 2012: "The key issue is crossing the border". He added: "Ideally it should be done with the full agreement of Baghdad. But it can be decided as a deal between Erbil and Ankara. For Erbil, it's a make-or-break issue. Turkey has the will."

The referendum debacle changed all that. Not only is there now no question that Baghdad would veto any attempt to lay such a line without its express permission, and that it has considerable power to enforce such a veto, but it looks increasingly as if Turkey regards the importance of its prospective energy relations with Federal Iraq as being at least as important – and quite possibly more so – than its energy relations with the KRG.

***Issues for Baghdad***

For Baghdad, there is also the question as whether it might be in a position at some time to export its own gas to Turkey or via Turkey to customers farther afield. As far back as 1996 – during the Saddam era – the Turkish Government identified the giant Akkas gas field, with reserves officially estimated at 158 bcm, as a prospective source of supply for Turkey, considering it could form the core of some potential 10 bcm/y of gas imports from Iraq. The memorandum of understanding signed that year was never implemented, but it was not forgotten. Akkas, in Anbar province and thus outside the KRG's domain, again came to the fore in August 2007 when Turkey and Iraq signed another MoU and set up a steering group to initiate feasibility studies into a gas transit pipeline to carry Iraqi gas to Europe via Turkey. The following January, Turkey's state pipeline company, BOTAŞ, agreed to conduct feasibility studies into a gas transit pipeline to carry Iraqi gas to Europe via Turkey.

In June 2011 the combination of Turkish interests in gas development and the prospect of a gas pipeline connection once again came to the fore. On June 5 Turkish Petroleum (TPAO) took stakes in two Iraqi gas fields. One was Mansuriyah, in Diyala Province, with an estimated 127 bcm in reserves, where TPAO would be both lead foreign partner and operator. The other was the much smaller Siba field, in southern Iraq, with reserves totalling just 2.9 bcm and with Kuwait Energy as operator. The agreements were signed just a few days after the Iraqis had finally awarded Akkas development to a consortium headed by the Korean Gas Corporation (KOGAS), one of TPAO's partners at Mansuriyah. On the pipeline side, Baghdad had by this stage long agreed in principle that Iraqi gas should at some stage be exported to Europe, with EU Energy Commissioner Günther Oettinger saying on 8 June 2011: "We are in contact with the new government in Baghdad to develop a new pipeline from Iraq, (to become) a part of our infrastructure." In the light of subsequent events, it should be noted that at this point Baghdad was thinking of exporting gas from Akkas and Mansuriyah to Turkey via Syria.

The outcome of these ventures was mixed. ISIS took over the Akkas and Mansuriyah fields in 2014 and were only expelled in 2017. KOGAS was subsequently reported to have sought to extricate itself from Akkas while on 31 July 2017 Baghdad, citing delay and failure on the part of the operator, announced that Iraq's own state companies would take over at Mansuriyah. Subsequent developments at both Akkas and Mansuriyah remain unclear. TPAO's website lists Mansuriyah as part of its foreign operations, but the posting appears to pre-date the Iraqi announcement. Only little Siba appears to be still on track, with a gas plant inaugurated in April 2018. But it is too far away – and far too small – to have any real bearing on the question of potential Iraqi gas exports to Turkey.

Nor does the bigger picture reveal anything to indicate any real push at present to develop Iraqi gas reserves for export to the north. Although Iraq has very substantial gas resources, with some 3.5 tcm of proven reserves that equate to 1.8% of global gas reserves, decades of warfare and economic sanctions have naturally led successive post-Saddam governments to focus on the development of oil exports to secure vitally needed funds for the massive reconstruction required. As a consequence, Federal Iraq has itself run short of gas so that it is now importing around 1.5 bcf/day (equivalent to around 15.5 bcm/year) of Iranian gas to ensure basic supplies, primarily in southern Iraq. It has told US officials, who want to see this trade ended, that it would take years to be able to secure alternative supplies.

This means that fields like Akkas and Mansuriyah, as and when they are developed, will initially be focused on the domestic market. But it also raises the question as to whether gas from the KRI might, in the end, be directed towards markets in Federal Iraq. Such suggestions were made in the past, both for direct gas supplies and, indirectly, in the form of gas that would be delivered to a Turkish power station at Silopi that would then export electricity to Mosul and other northern cities in the Federal Government's direct area of responsibility. Indeed, in April 2013, Turkey's Kartet, a subsidiary of the Karadeniz group, was reported to have secured an agreement to provide 200 MW/year to Mosul from Silopi, apparently as part of an agreement with the KRG.

## 9.5 Conclusion

There is, at present, little prospect of direct Iraqi exports to Turkey, let alone through Turkey to customers who might be supplied by means of the SGC. Moreover, so long as Iraq itself requires gas supplies, and so long as the US can bring effective pressure to bear on Baghdad to reduce and then eliminate its reliance on Iranian gas imports, it seems logical to envisage that at least part of any export capacity that the KRI might develop would be directed towards Federal Iraq. Much will depend on how much pressure Baghdad can bring to bear on the question of KRI gas development and on the role that Rosneft might play. Rosneft is clearly the major foreign player in KRI gas politics, and its agreements with the KRG have incurred the wrath of Baghdad.

But not only is Rosneft a power in its own right, not least because of the close personal relationship between Rosneft CEO and Chairman Igor Sechin and Russian President Vladimir Putin, but it also has a stake in Federal Iraq, with its subsidiary, Bashneft International, reporting the discovery of a new oil field, Salman, in Southwest Iraq in May 2018.

In sum, it will require all of Sechin's legendary diplomatic skills if the commercial opportunities available to the KRI from potential gas exports to Turkey, or through the SGC to markets farther afield, are to be realized. And it will also require considerable further expenditure on the part of Rosneft.

Chapter 10

# Nord Stream 2 – a Pipeline Project Dividing the EU

# 10. Nord Stream 2 – a Pipeline Project Dividing the EU

by Dr. Jörg Himmelreich

## 10.1 Introduction

Barely another pipeline project has raised such contentious political and legal discussions in the EU about European Energy Security as the construction of Nord Stream 2 presently does (Chazan and Astrasheuskaya, 2019). Moreover, no other European pipeline project demonstrates the close interconnectivity of economic, political and legal implications of every European gas supply agreement as Nord Stream 2 does.

This contribution will focus on the legal implications of the project after having briefly summarized the recent history of German – Russian gas relations and of the development of European Energy Law concerning the European gas market as background for the present controversial legal discussions about Nord Stream 2.

## 10.2 European gas relations with Russia

As it is well known, by the construction of transit diversification pipelines – principally Nord Stream 1 and 2 and Turkish Stream – 51% state owned Gazprom is aiming to minimise transit across Ukraine, and eventually reduce it to zero (Pirani, 2019). Gazprom with its 100% subsidiary Gazprom Export holds the monopoly on Russian pipeline gas supplies to Europe with Germany being the main market in Europe. After the completion of the 55bcm/year capacity Nord Stream 2, together with the parallel Nord Stream 1 pipeline (already completed) with an equal transmission capacity of 55bcm/year, more than 80% of Russian gas supplies to the EU will be concentrated in this narrow Northern corridor (Borchardt, 2017). With this circumvention of Ukrainian territory Gazprom intends to avoid supply interruptions such as occurred in 2006 and 2009. In a broader political context this is a way to exclude Ukraine from earning transportation fees.

The EU's future gas demand is difficult to assess. The overall total demand for Russian gas imports in Europe is estimated in the range of 176-212bcm/year or 171-181 bcm/year depending on whether Asian LNG demand is high or low, with corresponding low and high LNG availability for Europe (Pirani, 2019). Gazprom's planned total non-Ukrainian transit capacity exceeds 200 bcm/year after Nord Stream 1, Nord Stream 2 and Turkish Stream are completed.

In view of the present European legal discussions it seems to be rather unlikely that Nord Stream 2 will be at all operational by 31 December 2019, when the current transit contract between Gazprom and the Ukrainian gas transit company Naftogaz will expire. Thus, new contract agreements must already be negotiated, taking the newest legal developments of European Energy Law into account.

The construction of Nord Stream 1 has already raised serious political complaints not only by Ukraine, but also by EU member states, such as Poland and the Czech Republic, who were concerned about decreasing transit fees from their existing pipelines. The construction of Nord Stream 1 raised broad European political criticism, which escalated into the present political fury about Nord Stream 2 such as had never been seen before.

## 10.3 Russian gas relations since 1998

One cause of this clash between the German and the European energy business, political and legal, is the particular, original structure of the German gas market. German governments and German gas suppliers had, thus, extraordinary difficulties in accepting the increasing role of the EU Commission (EC)in the European gas business and in adjusting to the EC legal requirements to frame the conditions for a privatized and liberalized European gas market in order to guarantee private business competition in a formerly rather oligopolistic market with mainly state-owned incumbents (Lohmann, 2006).

The German gas market consisted of a three-tier-structure, with six large producing and five importing companies at the first level. They sold gas to 10 regional transmission companies at the second level, which then transported and sold gas to around 700 regional and municipal distribution companies – the third tier (Lohmann, 2006). While in other EU states the national gas market was dominated by one state-owned monopoly/company, in fundamental contrast the national German gas market was characterized by different private companies with cross-ownership and some municipal shareholders. The dominant players were the importing companies – with Ruhrgas being the main German player. But all were interconnected by mutual legal ownerships and gas sales contracts (Lohmann, 2006). The vertically integrated business models of the German companies were based on regional horizontal demarcation and gas grids (Westphal, 2017).

The Russian gas supply partner has been and is state-owned Gazprom. As successor of the Soviet Ministry for Energy it formed 1992 the holding company for the entire Russian gas production and transport infrastructure, with its 100% subsidiary Gazprom Export as the monopolist for gas exports from Russia. Given this ownership structure of the German and Russian gas markets Gazprom was only enabled to export and to sell gas to the dedicated large German gas import companies on the wholesale market at the “flange” at the border (Westphal, 2017). Commercial gas trade remained a purely bilateral venture that joined Gazprom Export and German import companies closely together for a considerable period of time by long-term sales contracts. The gas supply contracts were always concluded long-term to secure a sufficient return on the long-term Russian investments into the pipeline infrastructure and to secure at the same time for the few German import companies stable long-term supply of certain gas volumes fixed in advance.

Since 2009 four main factors have started to cause fundamental and accelerating changes to these “old times” - bilateral German – Russian gas relations:

- The EU’s internal market policies and reforms have not only transformed fundamentally the European gas market and business models, but they also influenced national and European policies and relations between companies more than before. The increasing roles and responsibilities of governments, and of the EC, European gas businesses and markets became more politicalised;
- The shale gas revolution and the following expansion of liquefied natural gas (LNG) trade broke seriously into the former rather oligopolistic German and other European national gas markets;
- The European and German “Energiewende” included new integrated EU climate and energy policies that transformed the assumption of growing European gas demand as a driver of a stable long-term gas supply relationship and introduced some degree of uncertainty and unpredictability; and
- The Russian-Ukrainian gas crises in 2006 and 2009 and the transit interruption through Ukraine in 2009 seriously undermined European trust in the reliability and security of Russian gas supplies and caused increasingly negative attitudes in the EU towards any cooperation with Russia.

The illegal Russian annexation of Crimea in February 2014 could ultimately only further undermine any remaining trust and brought European and German political relations with Russia to an all-time low and fundamentally affects European and German gas relations with Russia (Adomeit, 2015). Common to all four factors is the obvious emergence of the EU, in particular of the EC, as a major political and legislative factor that increasingly replaces the role of the single national EU member state in every aspect of internal or external energy and gas policies. The EU has now to approve and monitor every single gas supply agreement – in spite of the formal split of authority between the EU and single member states over energy policy according to the Lisbon Treaty.

Pushed/Pressed particularly by Eastern European member states the EU responded to the political event of the Russian annexation of Crimea with economic sanctions and by publishing the EU Energy Security Strategy (Communication from the Commission to the European Parliament and the Commission, 2014) in May 2014 and the EU Energy Union strategy concept in early 2015 (European Commission, 2015a). Both documents underline security of supply and the requirement of diversification of suppliers as key strategic objectives of EU energy policy. Both demands reflect the concerns about Russian supply interruptions and about a growing EU dependence on Russian gas supplies. After the Ukrainian gas supply interruptions in 2006 and 2009 and even more so after the Russian annexation of Eastern Crimea, EU member states perceived Russia's gas supply policies as a threatening "weaponization of gas" and Russia using European gas supply as an instrument to promote Russian foreign policy interests (Kocak & Micco, 2016). This perception influenced the EU's view of Russian gas supplies to Europe and to single member states and highlighted the geopolitical implications of almost every gas supply contract – an implication that German chancellors pretended occasionally to ignore in public.

Had the German government still been able to overcome politically the concerns of the EU and single member states as to North Stream 1, the opposition of the EU and single member states to Nord Stream 2 mounted to a degree that the German government probably has not foreseen. For all of them Nord Stream 2 violated the political, ultimately not legally binding principles, established in the concept of the EU Energy Union, namely supply diversification, security of supply and supply solidarity. In a letter to the EC Vice-President responsible for the Energy Union the energy ministers of seven Eastern and South-eastern EU member states wrote that the Nord Stream 2 project implied "alarming aspects" with negative effects on the "energy policy in Europe" (Hudak, 2017). Nord Stream 2 would be a "destruction of the energy union".

In summer 2016 the Polish anti-monopoly authority UOKiK refused to endorse the commercial deal because in its view the five Western partners of the Nord Stream 2 consortium would through the project achieve illegal large market shares in the Polish market. The deal forced them to transfer their ownership of pipelines entirely to Gazprom and to accept, in a financing agreement in April 2017, the weaker consortium position as a pure financial partner financing 50% of the costs. North Stream 2 was initially established as a joint venture between Gazprom and five European companies (Uniper, Wintershall, Shell, OMV and Engie) but this structure was abolished due to objections from the Polish competition authority and the subsequent start of infringement procedures. Gazprom became the sole owner, 'Poland's anti-monopoly office opens proceedings against Nord Stream 2 (Reuters, 9 May 2018).

Sweden, being alerted to increasing Russian military activities in the Baltic Sea since 2014 appealed to the EC at the end of January 2017 to assess the legal and political dimensions of Nord Stream 2. Denmark joined this appeal and passed a law that enabled Danish authorities to block Nord Stream 2 construction through Danish waters for security and foreign policy reasons[14]. Their decision is still pending[15] and seems to depend on the support of it by the U.S. administration. Members of the European Parliament demanded an "urgent action …to stop the Nord Stream 2 project"[16]. This political background influenced essentially the legal debates on the validity of the North Stream 2 project.

The growing legislation and legal interventions of the EU and the EC in relation to the European gas market will be looked at in the following.

## 10.4 Legal dimensions of North Stream 2

***a. The Third Gas Directive***

For the establishment and functioning of the internal market the new legal European energy architecture is mainly based on Art. 194 and Art. 216 TFEU 9 (Directive 98/30/EC)[17]. Art.194 stipulates that the Union policy on energy shall aim to (a) "ensure the functioning of the energy market and (b) the security of energy supply in the Union….and (d) to promote the interconnections of energy networks". Art.216 permits the Union "to conclude an agreement with one or more third countries …where the Treaties so provide or where the conclusion of an agreement is necessary in order to achieve, within the framework of the Union's policies, one of the objectives referred to in the Treaties…". [18]

[14] Reuters (2017b): 'Denmark seeks to change law on pipelines amid Nord Stream 2 divisions', Reuters, 9 April 2017, available at [online]

[15] Denmark still working on Russia's Nord Stream 2 gas pipeline permits', Platts, 7 March 2019, [online]

[16] Urgent action required to stop the Nord Stream 2 project', Letter from members of the European Parliament to the president of the European Council, Donald Tusk, the president of the European Commission. Jean-Claude Juncker, high representative of the EU for foreign affairs and security policy, Federica Mogherini, vice president of the EC for the Energy Union, Maroš Šefčovič, and commissioner for climate action and energy, Miguel Arias Cañete, 30 March 2017.

[17] Consolidated version of the Treaty on the functioning of the European Union (2009). [online] This is the version of the Treaty establishing the Consolidated version of the Treaty on the Functioning of the European Union. This is the version of the Treaty establishing the European Economic Community that has been in force (and renamed) as of 1 December 2009, as amended by the Treaty of Lisbon (2007) and all preceding treaties.

[18] Ibid.

Based on these Articles the EU adopted in 2009 the Third Package of energy legislation (here: Third Gas Directive), which was the latest major legal endeavour (law, “package”) by the EU[19] to transform the European gas market by law into a liberal, competitive, well-functioning integrated market by excluding the privileges of national vertically integrated incumbents that owned and operated generation and networks at the same time (Directive 2009/73/EC). Particularly relevant in this Third Package is the Third Gas Directive (Regulation (EC) No 715/2009) and to some extent also the Gas Regulation (Leal-Arcas, 2017).

The Third Gas Directive demands four essential elements of energy supply regulation:

1. unbundling of vertically integrated undertakings;
2. third party access;
3. transparent tariff methodology and
4. a transparent network of regulatory and supervisory institutions. Actually, the whole legal and political discussion about Nord Stream 2 centres on the question whether and, if yes, to which extent the Third Gas Directive is applicable to this pipeline project.

Already the construction of Nord Stream 1 had caused considerable concerns in the EC and in EU Member States. The concerns referred to the OPAL onshore transmission pipeline from the German port of arrival at Greifswald to Brantov in the Czech Republic (Yafimava, 2017).

Due to Gazprom’s overwhelming market share in the EU gas supply market, which affected the diversification of demand and the guaranteed third-party access provisions of the Third Gas Directive, at first in 2009 the EC only permitted Gazprom the use of 50% of OPAL. It later modified this decision to give Gazprom, as an exemption, the right to bid in an auction for 30% of the remaining 50% (EC Decision of 28/10/2016)[20]. Poland sued the EC at the European Court of Justice (ECJ) in 2016 to withdraw this exemption decision. The ECJ judgement is still pending, and the capacity of OPAL and Nord Stream 1 is still not used to the full.

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[19] The EU started this process of legal framing of the European Gas market in 1998 with the Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 Concerning Common Rules for the Internal Market in Natural Gas, Office Journal (OJ) L204, 21 July 1998.

[20] EC Decision of 28. October 2016 C(2016) 6950 final, 31. [online]. Both decisions were a sharp correction of the decision of the Bundesnetzagentur, the German energy regulator, that had granted an entire exemption to the Nord Stream 1 consortium for OPAL with some caveats. The Bundesnetzagentur based its exemption permission among other reasons on the rather simple assessment that the Nord Stream 1 Project ‘is of European interest’, ignoring all opposition from other EU member states. [online]

***b. Negotiation Mandate for the European Commission?***

Presumably encouraged by the fierce opposition of many member states against the Nord Stream 2 project, the Directorate General for Energy (DG Energy) of the EC submitted to the Council of the European Union (EU) a Draft for an amendment of the Third Gas Directive that would authorize the EC to negotiate an agreement between the EU and Russia on the Nord Stream 2 project. A negotiation mandate for DG Energy would have replaced the German responsibilities and rights, that Germany would have enjoyed before[21]. In the introductory memorandum to the proposed amendment draft the DG EC refers to the aforementioned EU energy policy objectives:

"The objectives of the European Energy Union framework strategy include an open and competitive internal energy market, security of energy supply and solidarity within the Union.

The EU only supports infrastructure projects that are in line with the core principles of the Energy Union, including those set out in the EU Energy Security Strategy as endorsed by the European Council in December 2015. Diversification of energy sources, suppliers and routes is crucial for ensuring secure and resilient supplies to European citizens and companies."[22]

As the construction of Nord Stream 2 "could decrease the role of existing transit routes via Ukraine/Slovakia and Belarus/Poland sharply and as Nord Stream 2 could also impact the overall gas supply architecture in the EU, by a replacement of eastern entry points for Russian gas within Central and Eastern Member States by entry points in the Western part of those Member States" the EC saw a requirement to give it (i.e. the EC) a mandate for negotiations with Russia "to establish an appropriate regulatory regime for the operation of the pipeline, which introduces the key principles of EU energy law and moderates the expected negative market impacts."[23]

Referring to the exclusive authority of the EU to negotiate agreements with third parties pursuant to Art.3.2 TFEU, if these agreements could affect the scope of common rules, the EC now requested a mandate to negotiate the Nord Stream 2 project with Russia. The EC admitted that the affected Third Gas Directive as an EU law can only regulate the market IN the territory of the EU, not outside it. Likewise, the Russian law concerning Gazprom can only be valid on the territory of the domestic Russian market. "Neither the EU nor its

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[21] The Draft Recommendation was strictly confidential but nonetheless leaked. EC (2017): 'Proposal for a Directive of the European Parliament and of the Council amending Directive 2009/73/EC concerning common rules for the internal market in natural gas', COM (2017) 660 final, 2017/0294(COD), Brussels, EC, 8 November 2017 (*'Amendment Proposal'*).

[22] Ibid., 2.

[23] Ibid., 3.

Member States could claim to have jurisdiction on the part of an offshore pipeline outside their territories. Likewise, no third country could impose the application of its national jurisdiction to offshore pipelines outside of its territory."[24] As two different law regimes – this of the EU and that of Russia – may not be applied on the offshore part of a pipeline at the same time according to the EC, this particular configuration would - as to the EC - constitute "a legal void for an offshore pipeline." This amendment proposal was politically supported by 13 EU member states.[25]

The Council's own legal service rejected the EC's request in its assessment on 27 September 2017.[26] It expressly noted that the Third Gas Directive "does not apply to the Nord Stream 2 pipeline,"[27] but neither assessed a conflict of two different legal regimes nor a legal void as to the offshore part of Nord Stream 2[28]. The legal regime of the offshore parts of the Nord Stream 2 pipeline through the Baltic Sea would follow the public international law of the United Nation Convention of the Law of the Seas (UNCLOS). The Council's legal service concluded by underlining the obvious political principle of every democratic legislator: "the decision whether or not to negotiate is not related to a legal need…., but instead a matter of **political** choice."[29] Thus, the legal service restricted its assessment of the obviously rather weak legal arguments of the EC and referred correctly to the political competences of the Council. The legal opinion did not advise the Council against a decision to approve the mandate. Within the scope of its shared competence with member states in matters to do with the Energy Union, certainly, the Council - driven by purely political reasons – could in principle decide to give the EC a mandate to negotiate a framework agreement with Russia on Nord Stream 2 to secure the supply, to guarantee third-party access to the pipeline and to safeguard the rules of free competition in the EU energy market. But given the shared political authority between EU and member states at least a qualified majority would be necessary in the Council for such a decision. That would mean 55% of EU member states voting in favour and these member states representing 65% of the population. The existing voting quora of Member States in the Council would not be sufficient. With strong

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[24] Ibid., 4.

[25] Reuters June 26, 2017, UPDATE 1- Thirteen EU nations back plan for talks with Russia over gas pipeline, [online]

[26] Opinion of the Legal Service of the Council, Opinion of the Legal Service of the Council of the EU, available in 'Council's legal arm shoots down Nord Stream 2 mandate request', *Politico*, 28 September 2017. [online]

[27] Ibid. para 44.

[28] As did already the EC's own legal service and the German transmission operator, Bundesnetzagentur [online]

[29] Opinion of the Legal Service of the Council.

opposition from key voting member states like Germany, the EC tried unsuccessfully to strengthen its political objectives by legal arguments.

### *c. Amendment of the Gas Directive 2009/73 EC*

After this failed EC attempt, a debate started to amend the Third Gas Directive to ensure that its requirements for unbundling, third-party access, open tariff schemes and transparency are also met by North Stream 2[30].

On 1 November 2017, the EC presented a proposal for an amendment of the existing Gas Directive 2009/73 to apply "the substantive rules applicable to gas transmission pipelines connecting two or more Member States to gas pipelines to and from third countries"[31]. Thereby the Commission pushes to apply many of the Gas Directive's key provisions to existing and future pipelines entering the EU from third countries up to the border of EU "jurisdiction", i.e. territory, territorial waters and exclusive economic zones of EU member states[32]. It intends to clarify the legal consequences when fundamental rules on unbundling, transparency, third-party access and regulated tariffs for "EU-internal pipelines" are applied to "external" ones. In principle the Commission proposal covers both existing and future "external" pipelines, unless (a) an exemption has been applied for in the case of new pipelines or (2) a derogation had been granted for existing import infrastructure (pipelines). Such a derogation from the requirements of the Gas Directive can be granted by the Member State where the first interconnection point – is located (Art. 49(9)) (European Commission, Proposal, s. fn. 38).

### *d. Council's Legal Opinion*

The proposal changed the definition of an "interconnector" in Article 2 (17) of the Gas Directive. An "Interconnector" pipeline is now defined as a "transmission line which crosses or spans a border between Member States for the sole purpose of connecting the national transmission systems of those Member States." By this enlargement of the definition of "interconnectors" the proposal now includes transmission lines that cross or span a border between Member States and third countries "up to the border of the Union jurisdiction". Whereas it states that the EU's jurisdiction on gas pipelines onshore to and from third countries remains confined to the territorial borders.

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[30] Negotiation mandate for Nord Stream 2: state of play: Klaus Dieter Borchardt, Director of Internal Energy Market at DG Energy, European Parliament Meeting (ITRE committee meeting, 11 October 2017 [online]

[31] European Commission, 'Proposal for a Directive of the European Parliament and of the Council amending Directive 2009/73/EC concerning common rules for the internal market in natural gas' COM (2017) 660 final, 2017/0294 (COD). (Proposal)

[32] UNCLOS differentiates the coastal waters of a state between territorial waters (22km) and the exclusive economic zones.

For offshore pipelines, however, the EU jurisdiction will be extended to EU territorial waters and the exclusive economic zone (EEZ). As a consequence, the Gas Directive's key rules will be applicable "also to offshore pipelines situated in their internal waters as well as in their exclusive economic zone (EEZ), as long as the offshore pipeline has an interconnection point with the Union network"[33]. The Council's Legal Service considered this extension of EU jurisdiction for offshore pipelines in the EEZ of Member States as invalid as this extension would be in conflict with the law of the United Nations Convention on the Law of the Sea (UNCLOS)[34].

Within the regime of shared competences pursuant to Article 4(2) I of the TFEU on the subject of energy Member States have currently the competence to regulate the operation of third-country interconnectors to which the Gas Directive 2009/73 according to its present form is not applicable. Thus, pursuant to Article 2(2) of the TFEU they have the competence to conclude intergovernmental agreements (IGA) to regulate the operation of such pipelines in their part outside of the EU and the third-country jurisdiction. After the EC attempt failed to receive a mandate to negotiate such an IGA with Russia as to Nordstream 2, the regulation competence[35] remained with Germany as the "Member State, of the first interconnector point."

### ***e. The Final Trilogue Proposal Agreement***

The political debates and negotiations between Member States, Commission and Council following the presentation of the EC amendment on 8 November 2017 and the publication of the Council's Legal Service legal opinion on it on 26 March 2018 continued, but took a surprising, sudden and fundamental turn at the Council's meeting on 8 February 2019[36]. A day before, leaks from the French government revealed that France would withdraw its constant support in the Council's meetings of the German obstructive position against any amendment of the Gas Directive 2009/73 EC that could endanger the completion of North Stream 2. This change in the French position shifted the balance of political support for the amendment of the Gas Directive in the Council overnight. Now a qualified majority quorum in the Council was achieved in favour of the amendment proposal. What looked rather unlikely throughout 2018 during the Bulgarian and Austrian EU presidencies, occurred now. The obstructing minority of Germany, Austria, the Netherlands, and Belgium had lost their blocking power. A compromise agreement between

[33] Council Opinion of the Legal Service 6738/8 (UNCLOS Opinion) (n 25) para 3.

[34] Ibid., para 5.

[35] Germany did not conclude an Intergovernmental Agreement as to Nord Stream 2.

[36] In blow to Germany, France to back EU rules on Nord Stream 2, Reuters 7 February 2019. [online]

France and Germany, hastily negotiated overnight, accepted in essence the major elements of the Commission's amendment proposal. The construction of Nord Stream 2 is still possible but will meet increasing legal hurdles and uncertainties which will lead to mounting additional costs. The result of the Council Meeting was for Germany at most just a face-keeping solution that proved Germany's isolated position in the EU as to Nord Stream 2.

The applicability of the amended Directive was only restricted to the territory and the territorial sea of the Member State where the first interconnection point with its network is located[37] and is not applicable to the exclusive economic zone (EEZ) of the Member State as the Council's Legal Service had earlier argued. As to Nord Stream 2 German authorities remained responsible for the necessary adjustments and had to decide on any exemption from the rules of the Gas Directive or derogation from it.

To agree on the legal rules to which extent the EC had to approve any adjusted decisions by the German authorities, and by which administrative procedures the decisions on exemptions and derogations should be granted for Nord Stream 2 a trilogue commission on the Directive on Gas – consisting of representatives of the Council, the Commission and the European Parliament - achieved a provisional agreement at its first meeting on 12 February 2019[38].

The European Parliament voted to adopt the provisional trilogue agreement at its first reading, and the European Council in turn approved it on 15 April 2019. The amendments to the Gas Directive 2009/73 became valid on 23 May 2019, and give single Member States, including Germany, a nine-month period to translate this new European law into their national legislation. Thus, Germany must transpose the amendments into its national law by 23 February 2020 at the latest, although Nord Stream 2 is still officially aiming to start its operations by the end of December 2019. As to the transposition of the Gas Directive into national law the German legislator has to follow closely the preconditions, definitions and legal consequences set up in the amendment of the Gas Directive.

### ***f. How do the amendments affect Nord Stream 2?***

When and to what extent will the Nord Stream 2 project partners have to adjust their project to the key requirements of the Gas Directive 2009/73/EU, at least for the extended German section in Germany's territorial waters? Could the German and EU authorities again grant an exemption or derogation for Nord Stream 2 from the key elements, such as unbundling, third-party access, transparency and regulated tariffs?

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[37] Ibid. Art. 1 (1), p. 8, amending Art. 2 (17) of the Directive 2009/73/EC.

[38] Council of the EU 14 February 2019, doc. [online] (provisional agreement)

The now binding and valid Commission proposal is generally shifting the existing balance of competences between the EU and its Member States towards a stronger position for the Commission.

After the extension of the applicability of the Gas Directive to offshore pipelines arriving in the territorial sea[39] of the "Member State where the first interconnecting point with the Member States' network is located", now not only the German territorial onshore pipeline connections with Nord Stream 2 but also the German part of Nord Stream 2 from its first connection point with the German domestic network at Lubmin – close to Greifswald – to the border between the German territorial sea and the German EEZ is subjected to Gas Directive 2009/73/EC. In addition, the requirements of unbundling the transmission from supply and production business, third-party access and regulated and transparent tariffs have to be met in principle by this section of the Nord Stream 2 pipeline.

***<u>What can German authorities and the project partners of Nord Stream 2 do to adjust the existing Nord Stream 2 project accordingly to the new legal situation?</u>***

Principally, four alternatives are possible in theory:

a. adjustment of IGA agreements,
b. a derogation from key principles of the Gas Directive,
c. an exemption granted by the German Bundesnetzagentur (BuNA) as the German national regulatory authority from the rules of the amended Gas Directive
d. the acceptance and implementation of all the requirements of the amended Gas Directive by all the Nord Stream 2 project partners, particularly by Gazprom as the 100% pipeline-owner.

**(a)** Pursuant to the introduction of the provisional agreement a "coherent and transparent procedure should be established to authorize a Member State, upon its request, to amend, extend, adapt, renew or conclude an agreement with a third country on the operation of a transmission line or an upstream pipeline network between a Member State and a third country"[40], whereas the "implementing powers to adopt decisions authorizing or refusing to authorize a Member State" for such a negotiation mandate are conferred to the Commission[41]. As there is no German-Russian IGA so far, it is rather unlikely that Germany would now start to initiate such a negotiation process. It would

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[39] The territorial sea is defined by the UNCLOS Art. 3 as the sea area within the 12 nautical miles limit around the coastline.

[40] Provisional Agreement (5b), p.5.

[41] Ibid (5e), p.6.

openly contradict the constant declarations of all German governments that Nord Stream 2 is purely a project of private energy companies, as misleading as those public declarations are. Moreover, Germany would have to ask for an authorization by the Commission for a Nord Stream 2 agreement. But this authorization procedure would include close supervision by the EC of single negotiation steps and would take time. So, it is rather unlikely that Germany and the Nord Stream 2 project partners will choose this option

**(b)** The amendments provide for the applicability of the rules of exemptions and derogations to different time references. The question arises: Who is responsible to grant an exemption or to accept a derogation and at which point of the whole European and national legislation process?

As the amendment was agreed at the Council's 15 April 2019 session, and published in the OJ EU L 117/1 on 3 May 2019 it became valid 20 days later, which is 23 May. The translation into German law must follow 9 months later, that is by February 23, 2020 at the latest.

The regime opening a "derogation" from key principles of the Gas Directive in its Arts. 9,10, 11, 32 and 41 para 6, 8 and 10 - such as the fundamental rules on unbundling, transparency, third-party access and regulated tariffs - is only eligible for existing pipelines (Hancher and Marhould, 2019). According to the new binding amendment the "Member State where the first connection point of such a transmission line ..."(between a Member State and a third country) .." may decide about a derogation only when this transmission line is "completed before the date of entry into force of this amending directive." As this amendment enters into force on 23 May 2019, but Nord Stream 2 will only be completed by the end of 2019 at the earliest, German authorities may not grant a derogation to Nord Stream 2. Thus, for this project only, the regime of an exemption according to Art. 36 is eligible under the preconditions mentioned therein.

**(c)** Pursuant to Article 36 of the original unamended Gas Directive the German "Bundesnetzagentur" (BuNA), as the national German regulatory authority, could grant an exemption from its requirements as it has already done for Nord Stream 1 (see above page 6). But now this exemption decision of the German BuNA would have to meet additional important requirements:

According to the new Art.36 para. 1, point (e) this "exemption must not be detrimental to competition in the relevant markets which are likely to be affected by the investment, to the effective functioning of the internal market in natural gas, the efficient functioning of the regular systems concerned, or to security of natural gas in the Union."

In addition, "before adopting the decision, the national regulatory authority….shall consult the national regulatory authorities of the Member States of the markets of which are likely to be affected by the infrastructure and the relevant authorities of the third countries, where the infrastructure in question is connected with the Union network under the jurisdiction of a Member State and originates from or ends in one (or more) third countries."[42]

So now the German BuNA will have to consult other national regulatory authorities, whose markets or jurisdictions are affected by North Stream 2, like those of Poland, Denmark and others, that have to respond within 3 months. After that period BuNA may decide, but only under the conditions "not to be detrimental to competition in the relevant markets…or to security of supply of natural gas within the Union". Presumably at least Poland will not agree to such a German exemption for Nord Stream 2. Many other Member States will again question the security of supply of Russian gas within the European Union, if after completion of Nord Stream 2 together with Nord Stream 1 80% of Russian Gas supplies to the Union will be transported through both parallel pipelines.

An exemption decision by the German BuNA after the finalized consultation process will have ultimately to be transmitted to the European Commission. Then the Commission may take a decision requiring the regulatory authority to amend or withdraw the decision to grant an exemption[43]. Given the detrimental effects of Nord Stream 2 to competition in the internal EU energy market and the security of gas supply within the Union it seems rather unlikely that the Commission would approve such an exemption decision of the German BuNA, but rather would be likely to withdraw it.

Independently from this consultation procedure "the national regulatory authorities of the Member States the markets of which are likely to be affected by the new infrastructure" (new Art.36 para. 3) – for example, the Polish national regulatory authority – also have the right to inform the Commission, if they do not agree with the exemption decision of the German regulatory authority. The Commission has finally the ultimate authority to require the German authority to withdraw its positive exemption decision.

After all: as to the legal regime of exemptions, Member States can no longer make unilateral decisions on exemptions. For new infrastructure national regulatory authorities of all Member States involved in such new infrastructure - as to Nord Stream 2 Poland, Denmark and Sweden - have to agree to such an exemption. So, the new Article 49 para. 1 extends the veto power of the Commission on new interconnectors to and from third countries. Member States may no longer decide unilaterally how to regulate their import pipelines with third countries.

[42] Ibid.

[43] Article 36 (9) par. 1 (not amended) Gas Directive 2009/73/EC.

**(d)** As all legal prospects of averting the application of the requirements of unbundling, third-party access and regulated and transparent tariffs seem to be rather unlikely to succeed for the Russian gas supply or the additional German section in the German territorial water from Lubmin to the border between the German territorial sea and the German EEZ of the Baltic Sea, the only way to complete Nord Stream 2 legally is simply to meet the requirements of the amended Gas Directive. That means:

(1) Nord Stream 2, and that means Russian state-owned Gazprom as its 100% owner, will have to reveal at least its tariff methodology for gas supply through this project, if not the tariffs itself.

(2) As to third-party access, Gazprom will have to find another partner that has gas and is ready to feed it into the Russian starting point of the Nord Steam 2 pipeline at Ust'-Luga. This is technically the only point at which gas can be injected for the new German section of its territorial sea between the German coast and the dividing line between the German territorial sea and the German EEZ. As this seems to be rather unlikely, the only solution could be that Gazprom Export, which has an exclusive export monopoly in Russia and is a 100% subsidiary of Gazprom, would be ready to transport a certain amount of gas on behalf of another Russian gas company which is not partly integrated with Gazprom. But Gazprom may not easily find another Russian gas producer to use Gazprom Export's transport capacities in Nord Stream 2.

(3) Meeting the unbundling requirement in the new German section will be the most complicated. A legally - or at least in its financial accounting independent - undertaking will have to be found to own the pipeline infrastructure in the German section. A newly founded transmission system operator (TSO) could become the new operator of the pipeline in the new German section of Nord Stream 2, or one of the TSOs that hold a stake in the EUGAL onshore pipeline which is connected with Nord Stream 2 at Lubmin. TSOs have to be certified by the national transmission authority and the certification has to be approved by the Commission. The certificates of the existing EUGAL TSOs have to be adjusted. If Nord Stream 2 should, according to its schedule. really be operational by the end of December 2019 - probably it will not - and the transposition of the amended Gas Directive into German Law is completed only later, the newly assigned TSOs as necessary operators of the

new German sector will have to apply for a certification[44]. If Nord Stream becomes operational after the transposition of the Gas Directive amendments into German Law on 23 February 2020, the operations of Nord Stream 2 will be blocked for another time period.

It seems that the project partners' strategy to build up facts that cannot be changed by disadvantageous amendments of the Gas Directive becoming valid, has failed.

If the Nord Stream 2 project partners, in particular Gazprom, find ways to include third party gas supplies in Nord Stream 2 and if Gazprom is ready to transfer the ownership of the pipeline in the enlarged German section to an (at least by financial accounting) independent undertaking[45], like one or two certificated TSOs, then, but only then, Gazprom could overcome the legal hurdles of an amended Gas Directive 2009/73.

## 10.5 Conclusion

After the amendments to the Gas Directive 2009/73 enter into force by 23 May 2019 and the transposition into German law by 23 February 2020 the key elements of the Gas Directive 2009/73, like unbundling, third-party access, transparent tariff methodology and to some extent transparent deal conditions will be applicable to North Stream 2. Nord Stream 2 is unlikely to receive an exemption of or a derogation from these requirements from the German authorities. The only way to keep Nord Stream 2 a legal undertaking is for its project partners to meet those requirements. Third party access and the unbundling of the additional German Nord Stream 2 section in the German territorial sea will be extraordinarily difficult to establish. It can only be speculated what will happen if no third party is ready to use Nord Stream 2. Then the German transmission authority might be pressed to think about exemptions, which the EU Commission would have ultimately to approve.

Besides this, a decision of the Danish authorities on permitting Nord Stream 2 to pass through Danish territorial waters is still pending. Finally, after negotiations for years the Danish Energy authority has recently permitted the third alternative route adjustment to the Nord Stream 2 consortium. This route is now passing with 147km the Danish EEZ Southeast of the Danish island Bornholm. The original completion date of 31 December 2019 for Nord

[44] Polish example

[45] An ownership unbundling is not required here, see: Katja Yafimava, Gas Directive amendment: implications for Nord Stream 2, OIES March 2019, p.2.

Stream 2, however, seems impossible to be met due to the delayed permission procedure of the Danish authorities. [46]

Finally, the wide political opposition to project will remain, if not increase. As soon as the Commission becomes involved in any administrative procedure as to NS 2 the already overwhelming political opposition will influence the EC's decisions. If U.S. President Trump's changeful announcements of political interventions against Nord Stream 2 should really lead to U.S. sanctions on the European NS 2 partners and force them economically to leave the project this would cause another serious impediment to making Nord Stream 2 operational. The result of all these legal and political uncertainties and the growing difficulties of making Nord Stream 2 operational might not entirely block the whole project but will enable the project partners to use only limited capacities. One result, that is certain, is: the costs of the project will increase.

Accompanied by hard political and economic tensions between Ukraine and Russia Gazprom and the Ukrainian Naftogaz have found - as expected - ways of prolonging their gas supply agreement beyond the expiry date of 31 December 2019 for another 5 years. Meanwhile at December 20th, 2019 U.S. – President Trump signed an immediately valid law that will impose sanctions on any firm that helps Russia's state-owned gas company, Gazprom, finish a pipeline into the European Union. A day after Allseas, a Swiss-Dutch company involved in the project, suspended its pipe-laying activities in anticipation of the sanctions, which will delay the pipeline completion for another year at least. As this pipeline laying under sea requires an extraordinarily special technology which only very few Western companies are able to deliver, whereas according to technology experts' Russian companies are unable to provide North Stream 2 with this technology, the finalisation of this project seems to be rather open now.

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[46] Dänen verzögern Nord Stream 2 (The Danes delay Nord Stream 2, Frankfurter Allgemeine Zeitung, 18 May 2019.

Chapter 11

# The Gas/Oil Price Inter-connection

# 11. The Gas/Oil Price Inter-connection

By Dr. Leo Drollas[47]

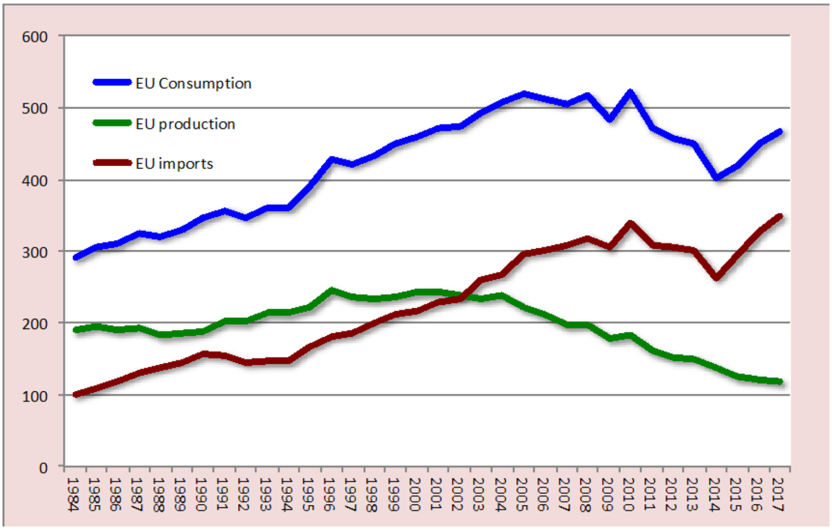
## 11.1 Introduction

Production of natural gas in the European Union has been on a downward trend since 2001 and, given that its consumption of gas has been almost static since then, the consequence of this output decline has been a surge in gas imports. The EU's rising dependence on imported gas, particularly from Russia, has raised questions of security of supply at a time of rising geopolitical tensions. In this context, developments in the South-East Mediterranean — where very large offshore gas discoveries have been made in the last couple of decades — are indeed significant. Properly exploited, some of these gas reserves could make a positive contribution to the security of the EU's future gas supplies, despite the region bordering on some of the world's major political fault zones.

The gas finds in the SE Mediterranean are not especially far from the EU's southern borders as the crow flies, but the pipelines that could carry gas supplies to Greece and thence to Italy would have to traverse deep waters, making them costly, although the cost side need not be an impediment to investment, provided the target markets can support prices that more than cover the cost of the investment, yielding in the process a desirable level of profit.  Will gas prices be at the appropriate level to justify such large expenditures? To attempt to answer such a question needs an understanding of what determines gas prices and — since gas prices are highly correlated with oil prices, as we shall see — a clear grasp of the factors that determine oil prices is required. This chapter contains an exposition of these factors and their evolution over the recent past and includes an attempt to discern where oil prices may be heading in the years to come.

[47] Dr Leo Drollas is an international energy consultant specialising in oil and gas matters. The econometric work contained in this chapter is original and was completed in January 2019

*Figure 72. Gas Consumption, Production and Imports in the EU (in bcm)*




***Sources: BP (2018) and Author's analysis***

## 11.2 The context

At 24% in 2017, the EU's share of natural gas in primary energy demand was very close to the global average of 23%, but less than the 28% in the US following the rapid development of its shale gas reserves (BP Statistical Review of World Energy, 2018). However, gas dependence in some EU countries was much greater than the EU average; for example, Italy's gas consumption in 2017 was 40% of primary energy, Hungary's 37%, the Netherlands' 36% and the UK's 35%. Most of the gas imported by the European Union in 2017 was via pipeline (74%), the rest being in the form of liquefied natural gas (LNG). Some EU countries imported all their pipeline gas from Russia — notably, Austria, Finland, Hungary and Slovakia — while Poland's share of gas via pipeline from the same source was 76% of total Polish pipeline imports, the Czech Republic's 64%, Italy's 42%, Germany's 51% and Greece's a very high 82%. Fortunately for southern Europe, the discoveries of natural gas in the SE Mediterranean since 1999 have been substantial (see Table 1). In this offshore region aggregate discovered gas reserves of 2.1trillion cubic metres (tcm) exceed the 1.7tcm reserves of both Norway and Kuwait and are 75% greater than the EU's own gas reserves. Just over half of these SE Med offshore reserves belong to Israel, 40% to Egypt and 8% to Cyprus. Most of the reserves of Egypt's massive Zohr gas field are earmarked for its domestic market, but the volumes of gas are so large as to permit substantial LNG exports via the two hitherto underutilised export terminals at Idku and Damietta on Egypt's Mediterranean coast. Current plans foresee gas from Cyprus' Aphrodite field landing in Egypt via the pipeline leading from Zohr, and the intention is to bring Israeli gas to Egypt, but these plans are likely to change with the development of the mooted East Med gas pipeline.

***Table 10. Natural Gas Discoveries in the South Eastern Mediterranean***

| Year | Field | Reserves (in BCM) |
|---|---|---|
| 1999 | Noah North, Israel | 1 |
| 2000 | Mari-B, Israel | 28 |
| 2009 | Tamar, Israel | 302 |
| 2009 | Dalit, Israel | 20 |
| 2010 | Leviathan, Israel | 616 |
| 2011 | Dolphin, Israel | 2 |
| 2011 | Aphrodite, Cyprus | 168 |
| 2012 | Tanin, Israel | 36 |
| 2013 | Karish, Israel | 101 |
| 2015 | Zohr, Egypt | 840 |
| | TOTAL | 2,115 |

***Source: Author's analysis***

The two EU countries most likely to benefit directly from the SE Med's offshore gas reserves are Italy and Greece, which is just as well given their heavy dependence on Russian pipeline gas. However, the East Med pipeline, which at present seems the most likely conduit for the SE Med's gas, is an expensive project that has to compete with the two existing Egyptian LNG plants. The East Med pipeline, starting 170km off the southern coast of Cyprus and stretching for 2,200km to Otranto on the heel of Italy via Crete and the Peloponnese in Greece, is scheduled to cost $7.36billion, with work set to begin in 2019 and to last for five years (Times of Israel , 2018). The pipeline's peak capacity is planned at 20 bcm/year, which would help to meet Europe's gas needs that are expected to increase by 100bcm from now to 2030, as the EU proceeds to reduce substantially its use of oil and coal — and eliminate hydrocarbons completely by 2050, highly ambitious as this may sound.

The equivalent annual capital [EAC] cost[48] of the East Med project, based on an assumed rate of interest of 4pc per annum and a depreciation period of 25 years, is $471million for each year of the project's assumed economic life. In

[48] The equivalent annual capital cost [EAC] is given by $EAC = A \cdot r / [1 - (1+r)^{-t}]$, where A: capital cost, r: rate of interest and t: depreciation period.

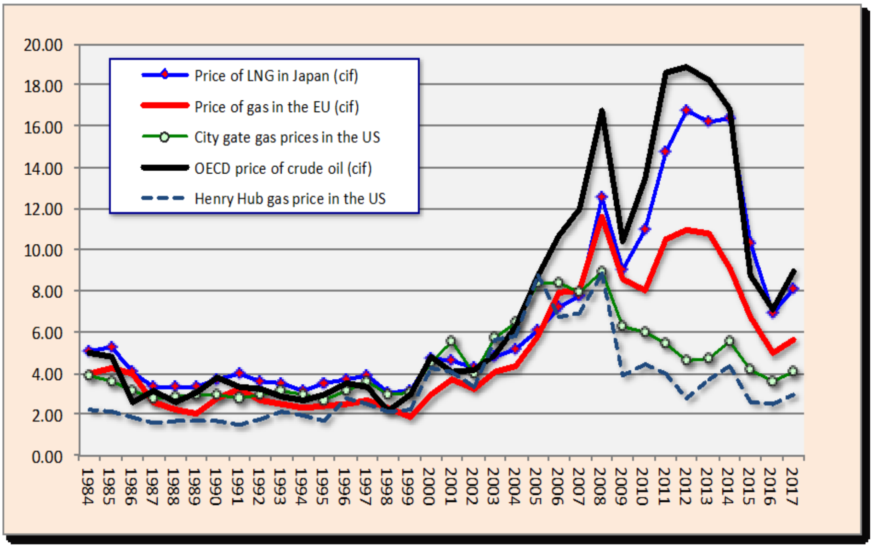
terms of the bcm/year of East Med's transportable gas capacity, the annual capital cost is $23.55million/bcm, or $0.69/mmbtu of gas at peak capacity. For purposes of comparison, Egypt's Damietta LNG plant, which came on stream in December 2004, has a liquefaction capacity of 6.8bcm/year and cost $1.3billion. Assuming a rate of interest of 44%/year and the same depreciation period of 25 years, the Damietta plant's EAC was $0.36/mmbtu, making it 48% cheaper than the East Med pipeline in capital cost terms. The Damietta LNG plant's operation was suspended in July 2012, because of a lack of natural gas due to Egypt's burgeoning local gas demand, but the plant is scheduled to restart in 2019, using gas surplus to domestic requirements from the country's giant Zohr field. The upshot of all this is that the East Med pipeline is a lot more expensive to build than a 5mt/year LNG plant, requiring correspondingly higher delivered gas prices to justify the investment, on the assumption that the operating costs for both systems are broadly similar and that the gas feed costs are the same.

## 11.3 Gas and oil prices

Natural gas has two basic sources. It is often found along with oil in joint formations and has to be separated from oil in gas separation plants. Since this so-called associated gas is a joint product with oil and can compete with it in the provision of electricity, industrial process heat and home heating, not to mention transportation in the form of compressed gas or even LNG, it follows that gas prices are likely to influence, and be influenced by, oil prices and move in a similar fashion. However, there is also non-associated gas, a growing source of natural gas in the world, especially lately in shale formations. Where non-associated gas is found in large enough volumes and close enough to its likely consumers, thereby reducing the costs of transportation, gas prices can follow an independent path from oil prices and have done so, the most striking example being the US from 2005 onwards.

US gas production prior to 2005 was hardly growing (0.1%/year between 1984 and 2005), but after the shale gas revolution, especially with respect to the massive Marcellus formation — located primarily in Pennsylvania, West Virginia and New York State — US gas production took off, growing at 3.4%/year from 2005 to 2017. As a result of this output bonanza, US gas prices broke away from oil prices in 2005 — exemplified by the average price of crude oil in the OECD countries — and have trended downwards since then. Wholesale US natural gas prices at Henry Hub in Erath, Louisiana, the delivery point for the New York Mercantile Exchange natural gas contract, declined by 66% between 2005 and 2017, while average US city gate gas prices dropped by 52% over the same period. The US gas market in the lower 48 states, based as it is on an extensive and well-developed national grid, is the closest we can get worldwide these days to a well-functioning gas market on a continental scale, responding quickly and efficiently to variations in demand and supply via changes in available stocks of gas.

*Figure 73. Global Natural Gas prices in US Dollars per million BTU*




***Sources: BP (2018), US Energy Information Administration and Author's analysis***

Elsewhere in the world gas prices have followed oil prices reasonably closely almost throughout the period 1984 to 2017. This is particularly true of a market like Japan, which is supplied exclusively by gas in the form of LNG from great distances away, transported in large, specialised vessels. When Japan started importing LNG in growing volumes from the 1970s onwards, it did so by signing long-term contracts with producers of LNG in the Middle East Gulf, Australia, Malaysia, Indonesia and others. Developing liquefaction plants and the gas carriers to transport the super-cooled liquid gas to Japan involved great expenditure and considerable risk, which could only be covered if delivered gas prices could be linked to a related fuel that would ensure an adequate return to the investors. At the time, oil, whose prices had increased dramatically as a result of the 1973 crisis. was conceived as the requisite anchor and so formulae were devised to link the price of delivered natural gas in Japan, via long-term contracts, to an average price of the various crude oils imported into Japan. Gas prices that moved up and down with oil provided the financial security that the investors in the very expensive gas chains – comprising gas production, liquefaction, transportation and regasification – needed to proceed with their investments. Thereafter, such formulae became the norm for pricing natural gas, not only in the Far East but also elsewhere in the world. Natural gas pricing remains linked to oil via formulae under long-term contracts, particularly regarding LNG, although in Europe the oil-based pricing system has largely been superseded by gas market orientated systems.

Nevertheless, despite these developments in Europe, the global gas market is still a long way from resembling the US example.

In the US, natural gas supplies and demand are linked via an extensive pipeline system and prices are set across the US with reference to a single benchmark, the Henry Hub price, just as crude oil prices in the US are set with reference to West Texas Intermediate (WTI) crude. In more recent times not all US crudes have been priced with reference to WTI, because this crude's market value has not reflected accurately enough its quality. Argus' Sour Crude Index (ASCI) has emerged in the US Gulf Coast as a useful reference crude for the more typical crude oils refined and traded in the area. Moreover, there is only one basic type of gas that is traded, dry gas with the natural gas liquids stripped out, whereas there are many different types of crude oil, whose prices are determined in terms of differentials with respect to a benchmark. In other words, the natural gas business in the US constitutes an efficient, transparent, and suitably incentivised industry that delivers the gas that is produced to where it is needed most, all under the aegis of market determined prices. It has taken many decades to reach such a level of organisation, whereas the rest of the global gas industry is still fragmented geographically, and the distances gas has to be transported from producer to consumer are much greater, especially in the Far East.

In Europe, most of the gas used is transported via pipelines that traverse a number of nations before the gas reaches its final destination. There are a number of European trading hubs where spot and futures gas prices are determined, the two largest by volumes traded being the Netherlands' Title Transfer Facility (TTF) and the UK's National Balancing Point (NBP). These days, about half of the gas contracts in Europe are still related to oil via longer-term contracts (particularly those concerning LNG) and the other half refer to spot gas prices that are determined in the various hubs. Since oil and gas are closely related hydrocarbons and there is considerable speculative cross trading in the European oil and gas exchanges, it is hardly surprising to find that the two sets of prices are highly correlated these days. In earlier years, European gas prices followed oil prices with an average lag of about a year, largely as a result of the structure of the contracts, but since the mid-2000s gas price changes in Europe follow oil movements without discernible lags, because of the greater use of contracts referring to spot gas prices that are influenced in turn by rapidly varying spot oil prices.

The changing relationships between the price of oil and various gas prices in Japan, the EU, Germany, the UK, the US and the world as a whole are shown in Table 2, which contains the correlation coefficients between the representative gas prices and the average price of crude oil in the OECD in various periods since 1984. During the earlier period, the price correlations in Japan, Europe and the world were lower than in the period 2000-17, whereas in the US they were higher. This is understandable due to the impact of shale gas in the US during the latter period, which caused a decoupling of gas prices from those of oil, as has been mentioned already and can be seen clearly in column two in Table 2. In Japan, and the Far East in general, gas prices remain highly correlated with oil (95% since 2000 for LNG, the only kind of gas imported by Japan), as indeed is the case in the EU (96% correlation with oil prices). At the world level, a weighted average global gas price index using gas consumption as weights had a correlation coefficient of 0.93 with crude oil over the period 2000-17 and a coefficient of 0.96 over the whole period 1984 to 2017. The message is therefore abundantly clear: gas prices in the world are highly correlated with oil prices.

***Table 11. Correlation Coefficients Between Average OECD Oil and Gas Prices***

| | 1984-99 | 2000-17 | 1984-2017 |
|---|---|---|---|
| LNG Japan, cif | 0.85 | 0.95 | 0.97 |
| EU gas price, cif | 0.65 | 0.96 | 0.98 |
| German gas price, cif | 0.65 | 0.96 | 0.98 |
| UK nat. balancing point | | 0.92 | |
| US Henry Hub | 0.24 | 0.05 | 0.53 |
| US city gate prices | 0.71 | 0.19 | 0.62 |
| Weighted avg world gas price | 0.77 | 0.93 | 0.96 |

**Note:** the weighted average world gas price is formed by using as changing annual weights gas consumption in the EU, Japan, China, South Korea, Hong Kong, Taiwan, the US and Canada.

***Sources: BP (2018) and Author's analysis***

Correlation, of course, does not imply causality, although there is a strong presumption that oil prices drive gas prices rather than the other way around. For one thing, most of the gas pricing contracts, especially for LNG, are set up in such a way as to state explicitly that the gas prices referred to are linked to oil prices via specific formulae. It should also be noted that the volume of traded oil in 2017 was 72% of the oil consumed in the world, whereas traded gas was only 31% of global gas consumption; indeed, the volume of physically traded oil in 2017 was 3.4 times greater than traded gas, both pipeline and LNG gas being treated as one. What is more, the world's paper markets for oil are much larger than those for gas, implying a greater transparency in price discovery and therefore a greater chance of identifying the correct price for the commodity in question at any time.

As further proof of the proposition that gas prices are driven by oil prices and not vice versa, a model of global gas price determination was estimated econometrically at an annual frequency between 1985 and 2017 by the author. As will be shown below, the initial specification was based on a dynamic disequilibrium adjustment mechanism, whereby the proportional change in gas prices is assumed to be a function of the proportional discrepancy between the demand for and the supply of gas. This mechanism was first used by the author in his study of the foreign trade sector in disequilibrium (Drollas, 1976), which specified that in a large trading nation both trade volumes and prices adjust to the disequilibrium between the demand for and the supply of exports and imports. Small trading countries are not expected to be able to influence the export and import prices they face; they are price takers in the same way an individual producer in a perfectly competitive market faces the market determined price. However, this cannot be assumed to be the case with a large trading country: its export and import prices are to some extent determined by the demand for and supply of its exports and imports. Using such a mechanism with respect to the gas market yields the dynamic equation below.

$$(1) \quad D \ln Pgas = g \ln [D^*gas / S^*gas] \text{ where,}$$

Pgas: price of gas and ln: natural logarithm

D*gas: demand for gas = $A\,(Pgas/P^\wedge)^b\, Y^c$

S*gas: supply of gas = $B\,(Pgas/P^\wedge)^k\, RP^m$

P^: price of a key rival fuel (=Poil)

Y: real global GDP

$b < 0, c > 0, k > 0, m > 0$

RP: global gas reserves to production ratio

D: differential operator (d/dt)

g: speed of response to discrepancy (>0)

On the plausible assumption that the response of gas prices to the disequilibrium is rapid when the time unit of estimation is a year, g tends to $\infty$ and we have the equilibrium relationship given by (2a) below in discrete time.

$$(2a) \ln D^*_t = \ln S^*_t$$

Or,

$$(2b) \quad \ln A + b\ln Pgas_t - b\ln Poil_t + c\ln Y_t = \ln B + k\ln Pgas_t - k\ln Poil_t + m\ln RP_t + u_t$$

Solving (2b) above for $\ln Pgas_t$ and performing various algebraic manipulations[49] yields the final form equation (3) below that was estimated with data from 1985 to 2017 (BP Statistical Review of World Energy 2018). The gas price is a consumption-weighted average of gas prices in key countries and regions, real global GDP is from the World Bank and the world's gas reserves-to-production ratio R/P is calculated from data in the BP Statistical Review. This procedure is based on a scheme developed by Prof. Denis Sargan at the London School of Economics in 1964 that linked static equilibrium economic theory with dynamic empirical models via a first-order autoregressive scheme in the errors. The Sargan procedure yields a final form equation that is the same as the one often used in co-integration econometric work (Hendry and Juselius, 2000), whereby changes in the dependent variable are a function (a) of the rates of change of the exogenous variables and (b) of the adjustment of the dependent variable to its steady state, with the parameter $c_1$ indicating the speed of this adjustment.

$$(3)\quad \Delta\ln Pgas_t = c_0 + c_1\ln Pg_{t-1} + c_2\Delta\ln Poil_t + c_3\Delta\ln Y_t + c_4\Delta\ln R/P_t + c_5\ln Poil_{t-1} + c_6\ln Y_{t-1} + c_7\ln RP_{t-1} + e_t$$

Empirically, the parameters $c_3$, $c_4$, $c_6$ and $c_7$ all proved to be statistically insignificant, suggesting that oil prices are the key, indeed the only, driver of global gas prices. Equation (3) was thus re-estimated with $\ln Pg_{t-1}$, $\Delta\ln Poil_t$ and $\ln Poil_{t-1}$ as the regressors, and the result is given below in equation (4), with the estimated parameter values and their 't' statistics (in absolute value terms) displayed in parentheses below each parameter. The adjusted $R^2$ of equation (4) is 0.62 and its standard error of estimate is 0.112, while the root mean square error (RMSE) of actual versus predicted gas prices over the sample period is 10.8pc.

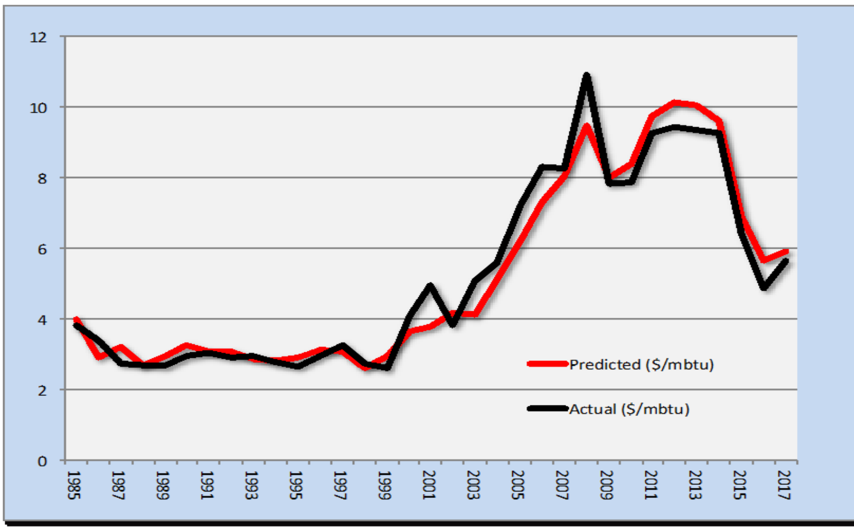
$$(4)\quad \Delta\ln Pgas_t = \underset{(2.75)}{0.213} - \underset{(3.79)}{0.634}\ln Pg_{t-1} + \underset{(6.94)}{0.515}\Delta\ln Poil_t + \underset{(3.69)}{0.439}\ln Poil_{t-1} + e_t$$

To deduce the direction of causality, equation (4) was estimated with changes in the price of oil as the dependent variable and $\ln Poil_{t-1}$, $\Delta\ln Pgas_t$ and $\ln Pgas_{t-1}$ as the regressors. The standard error of estimate of this equation was 53% greater than that of equation (4), implying that oil prices drive gas prices, and not the other way around, although it must be noted that both prices are obviously related, since they refer to hydrocarbons that are often jointly produced and that compete in certain sectors. Figure 74 shows how close

[49] Assuming the error term $u_t$ is autocorrelated according to the first order scheme $u_t = r\,u_{t-1} + e_t$, where $e_t$ is a random normal variable, lagging (2) once and multiplying each term by 'r', subtracting the resultant equation from (2) and further manipulating the equation by adding and subtracting various terms, yields the final form equation (3) whose error term should be random normal.

equation (4)'s predicted gas prices were to actual prices over the period 1985 to 2017. They could, of course, have been closer, since the predicted gas price's RMSE was above 10%, but it is important to acknowledge the key message from equation (4), viz. that the observed changes in global gas prices over the period 1985-2017 depended on oil prices for just over half of their annual variation (note that the parameter $c_2$ equalled 0.51).

***Figure 74. Actual and Predicted Global Gas Prices in US Dollars per million BTU***




**Note:** Calculations are based on ex post, one-period-ahead predictions from equation (4)

***Source: Author's analysis***

## 11.4 Oil price formation

Since gas prices are heavily influenced by oil prices, the obvious question arises: what factors lie behind the movement in oil prices? However, before an answer to this question is attempted, it would be apposite to cover, perforce somewhat briefly, the historical background to oil price formation in order to put into context the current state of affairs. Prior to 1973, and the first oil price crisis, the so-called seven sisters[50] dominated the oil business. These seven

[50] This soubriquet was given in the 1950s to Exxon, Shell, British Petroleum, Mobil, Texaco, Chevron and Gulf Oil by Enrico Mattei, the chairman of ENI, the Italian oil company. Mattei came into conflict with these seven majors because ENI, having no oil production of its own, felt

large companies ran vertically integrated oil chains from oil well to ultimate consumer and in their heyday controlled over 75% of global oil. Most of the oil that was produced, much of it under the concessionary system prevalent at the time, was traded within the oil companies' internal networks, between their upstream producing arms and their refining operations. This oil was sold at so called 'contract' or 'term' prices that were specified in short- to medium-term contracts between the upstream and downstream arms of the companies. The contract prices were related, on the one hand, to the so-called 'posted' or tax reference prices, i.e. those prices upon which the host governments (viz. those granting the concessions) based their tax take, and on the other to the so called 'cargo' prices. These latter prices were akin to what we would call 'spot' prices today and referred to those relatively few oil cargoes that were sold outside the oil companies' integrated systems to third parties. Although the 'cargo' prices applied to only about 5% of the oil moved around the world, they were influential because they represented the price of the marginal barrel. With fairly long delays these cargo prices drove contract prices, until 1970 usually downwards, due to the growing abundance of oil supplies.

After October 1973 and the Arab oil embargo that caused spot oil prices to rise fourfold in a month or so, the pricing initiative passed to the OPEC countries, who endeavoured to take control of their oil industries, a task completed with the nationalisations of 1975. Thereafter the international oil trading system was characterised by two main prices, the official government selling prices or OGSPs, successors to the aforementioned contract prices previously set by the companies, and the spot prices, which now applied to the non-contract oil sold on the open market. This pricing system is more-or-less what still applies today, but a couple of important changes altered considerably the nature of oil price formation. Since 1983 and the advent of the West Texas Intermediate (WTI) oil futures contract on the New York Mercantile Exchange (NYMEX), there grew over time a huge market in paper oil on both sides of the Atlantic. (Note that the Intercontinental Exchange, or ICE based in London, constitutes the largest market for the Brent futures contract). Spot prices, which refer now to cargoes with a specific loading date, still play a key role in oil price formation, but they interact closely with the front month futures price, because on expiry of each futures contract its price converges to the relevant spot price. Indeed, convergence is essential, given that the settlement of contracts these days is invariably made in cash (rarely are they settled by physical delivery) and with reference to the relevant spot price. What is more, the set of futures prices stretching along the forward curve interact with the current or spot price to generate incentives or disincentives to store oil; a transmission mechanism is thus created whereby expected market pressures in the future affect spot prices in the present. For example, if

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at their mercy. For details see *"Oil: The Devil's Gold"*, Leo Drollas and Jon Greenman, Duckworth, 1989, page 36.

oil is expected to be more plentiful in the future than at present, the forward curve moves into 'backwardation', viz. the futures prices are lower than the spot price of oil.

This creates pressure on those who have stocks of oil that are surplus to current requirements to sell their excess oil into the spot market and simultaneously buy back the oil in the futures market, thereby locking in a profit. On the other hand, when there is a lot of oil currently available compared with expected supplies in the future, the market moves into 'contango', with spot lower than futures prices, providing oil players with the financial incentive to buy spot oil and simultaneously sell futures, once again locking in a profit should the price difference exceed the cost of storage over the period. Expectations of where the oil market is heading thus play a big role in spot price determination, because the market's players, separated into hedgers [who have physical oil to sell, or want to purchase physical oil] and speculators [who do not wish to provide actual oil or take delivery of oil supplies in settlement of their contracts], participate in the paper markets in order to fix prices today for future (usually cash) settlement and in so doing move spot prices too via the transmission mechanism described above. Oil inventories and their desired level therefore constitute the key element in oil price determination.

With well-established, highly liquid and transparent futures markets that set, in real time, monthly prices of the key benchmark crudes stretching ahead in time, which, in turn, influence spot prices, the producers of any kind of oil anywhere in the world are able to set their official selling prices above or below just a few global benchmarks. Deliveries into NW Europe are based on Brent, those to the Far East on Dubai-Oman crude and those to the US on WTI, and increasingly on Argus' Sour Crude Index (ASCI). One detail needs to be pointed out: a number of such contracts, like Saudi Arabia's for example, have destination restrictions under which the buyer is required to specify where the oil is heading so that the price differential of Saudi crude is applied to the correct benchmark. The upshot of all this is that the phrase 'determination of the price of oil' is not a simple matter of defining a particular oil price and then trying to find what drives it. There are only a couple of benchmarks, like Brent and WTI, which have truly worldwide appeal and with which most other oil prices are linked, and it is upon WTI that we shall concentrate in our quest for price determining factors, largely because oil inventory data are readily available in the US, even down to a weekly frequency, although in this case a quarterly model was estimated empirically.

## 11.5 Short-term oil price determination

As mentioned above, the evolution of oil futures markets made the interplay between spot oil prices and futures prices an important factor in determining the level of crude oil stocks that traders and refiners wish to hold at any moment. This is of great significance, for it guides us in the direction of inventory disequilibrium as a key driving force of oil price changes, at least in the short run. The ability to set a price today at which oil is acquired or delivered in the future allows oil to be, so to speak, ‘loaned’ or ‘borrowed’ over time at a profit. Thus, the traditional motives for holding stocks, i.e. the need to meet expected demand [the *transactions motive*] and as a precaution against unforeseen losses of oil supplies [the *precautionary motive*], are augmented by what might be termed the *profit motive* for holding, or disposing of, surplus stocks that the presence of a liquid futures market allows.

A US-centred model determining spot WTI prices via stock disequilibrium is presented below. Note that the transactions motive for holding stocks is represented by US refinery throughputs and the precautionary motive is assumed to be a function of OPEC’s spare capacity. Since OPEC is the world’s self-appointed residual supplier of oil, the greater the amount of spare capacity it has, the greater the amount of spare capacity available in the global oil system and, therefore, the less need there is to hold precautionary stocks of oil. As for the profit motive for holding surplus stocks, it is assumed to depend on the proportional excess of the $4^{th}$ month WTI futures price over the spot price of WTI.

$$(5) \quad D \ln Poil = v \ln [\, ST^* / ST \,] \text{ where,}$$

Poil: spot price of WTI and ln: natural logarithm

ST*: desired US oil stock levels = $A\ TR^a\ (Pf/Poil)^b\ SPC^k$

ST: actual level of US crude stocks

Pf: 4-month WTI futures price at NYMEX

TR: US refinery throughputs (transactions motive)

SPC: OPEC’s spare capacity (precautionary motive)

$a > 0$, $b > 0$, $k > 0$

D: differential operator (d/dt)

v: speed of response to stock disequilibrium (>0)

On the assumption that the speed of response of WTI to stock disequilibrium in the US is extremely rapid even within a quarter, which is the time unit of estimation in this case, “v” tends to $\infty$ and once again we have the equilibrium relationship (6) below in discrete time.

$$(6) \quad \ln ST^*_t = \ln S_t \text{ or } \ln A + a\ln TR_t + b\ln Pf_t - b\ln Poil_t + k\ln SPC_t = \ln ST_t + u_t$$

Solving (6) above for $\ln Poil_t$ and performing various algebraic manipulations[51] yields the final form equation (7) below that was estimated with quarterly US data from 2Q99 to 3Q18 (EIA, Author's estimations).

As described earlier, this procedure is based on a scheme developed by Prof. Sargan that links static equilibrium economic theory with dynamic empirical models via a first-order autoregressive scheme in the error term $u_t$. The Sargan scheme yields equation (7).

$$(7) \quad \Delta\ln Poil_t = m_0 + m_1 \ln Poil_{t-1} + m_2 \Delta\ln TR_t + m_3 \Delta\ln Pf_t + m_4 \Delta\ln ST_t + m_5 \Delta\ln SPC_t + m_6 \ln TR_{t-1} +$$

$$+ \; m_7 \ln Pf_{t-1} + m_8 \ln ST_{t-1} + m_9 \ln SPC_{t-1} + e_t$$

Equation (7) was estimated using quarterly data over the period 2Q99 to 3Q18 and the result is given below in equation (8). The 't' statistics (in absolute value terms) are displayed in parentheses below each estimated parameter value, while the adjusted $R^2$ of the equation is 0.98 and its standard error of estimate is 0.022. The percentage RMSE of the actual versus the predicted WTI spot prices over the sample period is 2.13pc.

$$(8) \quad \Delta\ln Poil_t = 0.492 - 0.303 \ln Poil_{t-1} + 0.073\, \Delta\ln TR_t + 1.088\, \Delta\ln Pf_t - 0.205\, \Delta\ln ST_t - 0.038\, \Delta\ln SPC_t + 0.067 \ln TR_{t-1} + 0.288 \ln Pf_{t-1} - 0.139 \ln ST_{t-1} + 0.016 \ln SPC_{t-1} + e_t$$

The estimation result suggests that the major influence by far on changes in spot WTI is the futures price's proportional changes, followed by the impact of changes in US crude stocks and, lower down the line, the effect of OPEC's spare capacity. It thus seems that the so-called profit motive for holding or disposing of surplus crude stocks predominates in the US, with the precautionary motive playing a lesser role. Interestingly, the transactions motive, which would have been considered important on a priori grounds, was not found to be a significant driving force as far as WTI price formation is concerned. The very large and transparent WTI futures market plays a key role in influencing (and being influenced by) the way spot crude prices move in the US, the world's largest consumer and producer of oil. Oil refiners hold, as a matter of routine, enough stocks of crude to meet their on-going requirements, but they are also perennially alert to opportunities offered by the WTI forward curve to store or dispose of oil surplus to their needs. At any one time the futures price itself encapsulates the market's collective

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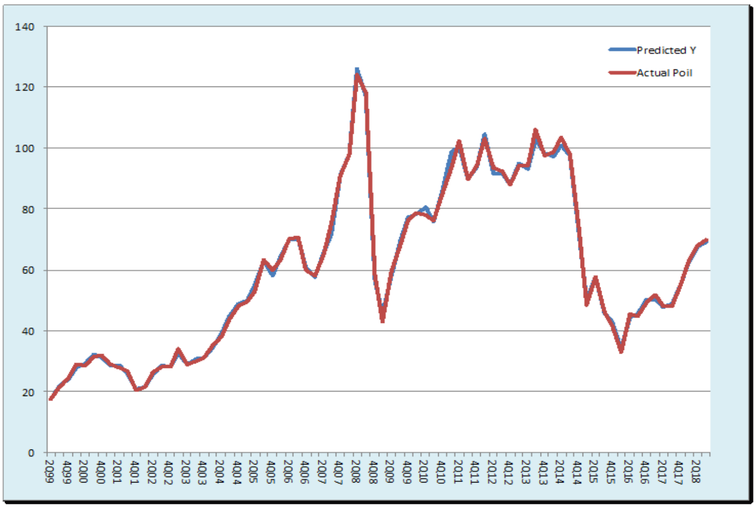
[51] The error term $u_t$ is assumed to be autocorrelated according to the first order scheme $u_t = r\, u_{t-1} + e_t$, where $e_t$ is a random normal variable. Lagging (6) once and multiplying each term by 'r', subtracting the resultant equation from (6) and further manipulating the equation by adding and subtracting various terms, yields the final form equation (7) whose error term should be random normal. Corresponding Standard Errors for Eq.8. (0.81, 4.27, 0.78, 51.6, 1.71, 2.33, 1.04, 4.42, 1.10, 1.72)

expectation of where it thinks the price is heading. This expectation, in conjunction with where the spot price happens to be, sets up forces that move both sets of prices.

***Figure 75. Actual and Predicted WTI Oil prices in US Dollars per Barrel***




***Note****: Calculations are based on ex post, one-period-ahead predictions from equation (8)*

***Source: Author's analysis***

In truth, the futures price is co-determined with spot prices and ideally should be estimated via a simultaneous-equation system, which has indeed been attempted in the past by the author in collaboration with Dr. Clifford Wymer. The Wymer-Drollas model of the global oil market is expressed in continuous time and was estimated using a discrete approximation of the continuous time system. The model not only determined the spot price of Brent, but also Brent's 4th and 6th month futures prices, the demand for and production of oil in the OPEC and non-OPEC areas, and global oil inventories (Wymer & Drollas, 2014). However, since both time and space constraints do not permit an update and presentation of such a model, suffice it to say that, for our purposes here, WTI spot prices in the short run are largely driven by the futures market and factors such as US crude inventories and OPEC's spare output capacity, the latter as an indicator of tightness or slackness in the global oil system beyond the shores of the US. Those readers who are well acquainted with the oil market know that oil politics, and in particular the periodic decisions of OPEC to curtail its production in order to shore up the price of oil, often influence crucially the path of oil prices. This characteristic of the oil market renders the prediction of oil prices over the longer term especially difficult and is worth bearing in mind whenever discussion turns to the more distant future.

## 11.6 Oil prices in the longer run

It becomes progressively more difficult to use short-term models of oil price determination, like the one presented above, to predict how oil prices will behave in the longer run – and not just for the reason presented at the end of the previous section. Although inventories do play an important role in oil price determination in the short term, they are not expected to perform a similar role over long periods of time, simply because the stock disequilibrium itself sets up reactions that should clear the imbalance between desired and actual stocks within a relatively short period. This, of course, leads to the philosophical conundrum whether the long run has an existence that is independent of the short run, or whether it is merely an accumulation of short steps in time. If the long run truly depends on successive short-run steps, then where we end up will depend on what has happened on the way and some of these developments are most likely to be unforeseeable, which renders forecasting at best fraught with peril and at worst impossible. Does this mean that since we are incapable of saying anything meaningful about the more distant future, we should refrain from doing so? Perhaps this would be wise, but because there is always an interest in the future, allow me to have a go, provided my musings are taken with a healthy pinch of salt.

It is safe to say that the price of oil is most likely to be driven in the long run by the need for oil in relation to the amount of it that is available to be extracted. In the simplest formulation, the demand for oil is generally understood to be a function of the real price of oil and an activity variable like real GDP. More elaborate schemes incorporate the oil-consuming capital stock and its utilisation rate, and since it is difficult to obtain data for the capital stock, this variable is eliminated in the process of obtaining a final form equation that can be estimated yet retains the model's structural features. These techniques have been used in the past to pin down the determinants of oil demand and have been reasonably successful. However, continuing success is not guaranteed, because governments are intervening increasingly in the energy market, especially in the European Union, in a concerted effort to phase out by government fiat the use of hydrocarbons, even in the transport sector, in the interests of avoiding harmful climate change.

Work undertaken by the author on the global demand for oil, based on an implicit capital stock adjustment model estimated over the period 1980-2017, suggests that under plausible long-run assumptions about the price of oil, global economic growth, world inflation and the value of the US dollar (see Table 3), the worldwide demand for oil is likely to rise by 20.6 mbpd (1.6 mbpd/year) between 2017 and 2030. This can be considered a business-as-usual scenario, but because the European Union, possibly followed by other groups of nations, is likely to continue on its present de-carbonising path, we need to take this into account in producing a more likely scenario, which may be called the "EU decarb" case. EU oil consumption peaked in 2006 at 15.12 mbpd and by 2017 it had declined by 1.91 mbpd, or 174 tbpd/year. On the assumption that the EU's decarbonisation drive will continue at the same pace, EU oil consumption should drop by a further 2.1 mbpd by 2030, which upon subtraction from the business-as-usual 20.6 mbpd global demand increment from 2017 to 2030 yields a worldwide increase of 18.5 mbpd.

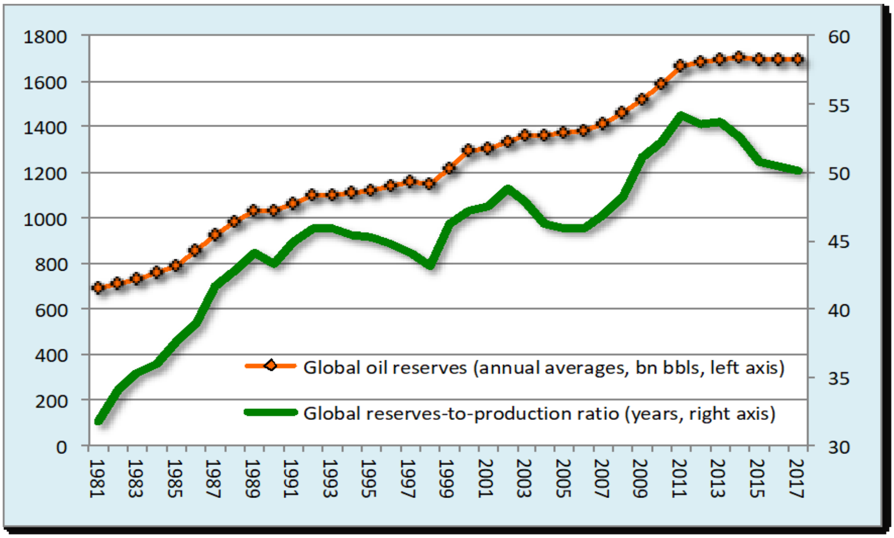
***Table 12. Global Oil Demand and its Drivers from 2000 to 2030***

| | Oil demand growth in % per year | Oil demand growth in mbpd p.a. | Oil price in nominal terms pc per year | Oil price in nominal terms $/bbl avg | World inflation avg per year | World real growth avg per year |
|---|---|---|---|---|---|---|
| **2000-2010** | **1.4** | **1.2** | **10.3** | **50** | **4.2** | **3.0** |
| **2010-2017** | **1.5** | **1.4** | **-5.5** | **80** | **2.9** | **3.0** |
| **2017-2025** | **1.5** | **1.6** | **4.9** | **61** | **2.9** | **3.0** |
| **2025-2030** | **1.4** | **1.6** | **1.2** | **80** | **2.6** | **2.7** |

***Sources: BP (2018), US Energy Information Administration, Bank of International Settlements, World Bank and Author's analysis***

Despite the substantial EU demand reduction, the remaining global demand increment is, nevertheless, considerable and begs the question whether world supply can provide enough oil to satisfy this additional demand. If this is not possible, then it is obvious that oil prices will have to increase at a faster pace than has already been assumed. In discussing whether global oil supplies will be able to rise at a rate that matches global oil demand growth, we need to consider (a) the path of the world's oil reserve base hitherto, (b) how many years' worth of current production (known as the global R/P ratio) the world has had and how this has changed over time, and (c) the world's natural decline rate, i.e. the annual percentage decrease in the world's oil reserves without taking into consideration any new discoveries, revaluations of existing reserves and extensions of oilfields.

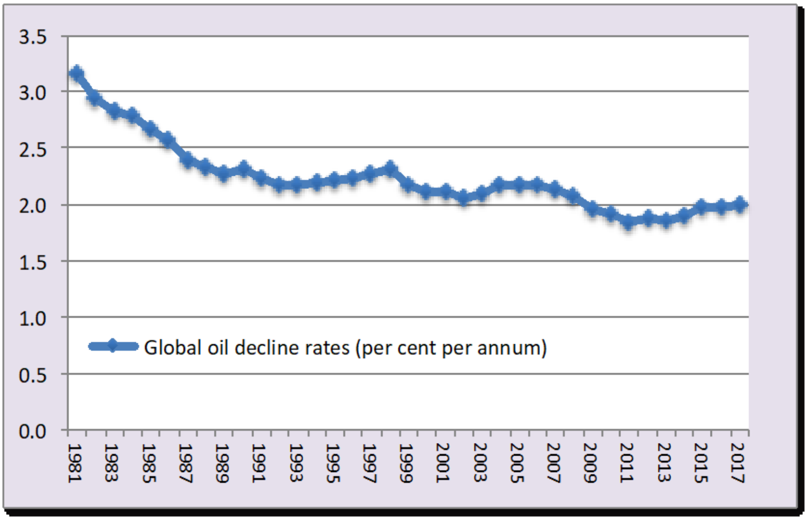
***Figure 76. Global Oil Reserves and the World's R/P Ration***




***Sources: BP (2018) and Author's analysis***

As Figure 76 clearly shows, over the last thirty-six years the world's oil reserves have been on an upward path. There have been years of stagnation, years of slow growth and years of rapid growth, but overall the reserves path has been upwards. The world's R/P ratio exhibits greater variability, but that too has increased substantially overall, from 32 years' worth of production in 1981 to 50 years' worth in 2017. It is true that the global R/P ratio has declined since 2011 by 4 years' worth, but this is not expected to last, because oil prices have risen since the depths reached in 2016 and oil prices are one of the key drivers of oil reserves. As for the world's decline rates, there is usually much discussion about how oil is a depleting asset and how high natural decline rates are certain to lead to higher prices, because gross additions to reserves (from wild-cat discoveries, revaluations and oilfield extensions) are unable to keep up with high rates of natural depletion.

*Figure 77. Global Decline Rates (% per annum)*




***Sources: BP (2018) and Author's analysis***

A look at Figure 77 dispels such fears, because the global decline rate, having dropped from over 3%/year in 1981 to 2.1% in 2002, has stayed around the 2% level since then and is unlikely to rise much, on present indications. Replacing 33.8bn barrels of oil (equal to the world's rate of oil production in 2017) each year sounds like a daunting task, but the world has indeed done just that by adding 33.4billion, 33.6billion and 33.8billion of gross reserves in the years 2015, 2016 and 2017. Indeed, as far as reserves are concerned the bottom line is quite simple: as things stand, the world has fifty years' worth of proven reserves to tap at current production rates, even if not a single additional barrel is added to them, which is highly unlikely, to say the least. The pessimism regarding reserve replacement arises from having a parochial outlook. Individual oilfields do decline over time and a few of them quite rapidly, but whole regions tend to have much lower natural decline rates and for the world as a whole the rate is around 2% at present. The rate of discovery never seems to dry up and revisions of, and extensions to, existing oilfields are part and parcel of normal oil operations. Moreover, a game-changing innovation occasionally makes an appearance that alters dramatically the oil scene.

The US shale oil story is a case in point. Hydraulic fracturing of oil formations was first tried in 1947 and the first commercially successful applications were by Halliburton in March 1949 in Oklahoma and Texas. George Mitchell is credited with being the first to apply the process to a shale formation, the Barnett shale gas field in Texas, in the early 1980s. The rest is, as they say, history and need not be repeated here except to point out that proven US oil reserves increased from 29.3bn barrels (with an R/P ratio of 11 years) in 2004 to a peak of 55bn barrels (R/P of 13 years) in 2014, when WTI was still above \$100/bbl in July of that year, just before the big price slide. This 25bn-bbl surge in US oil reserves — incidentally, more than double the current reserves of Algeria — was entirely due to US shale formations and, of course, the high price of oil. Unfortunately for the US, its reserves had dropped to 50bn barrels by the end of 2017 (R/P ratio of 10.5 years), due to the heavy fall in the price of oil from the heights of 2013-14 and the record rates of oil production in 2017. This decline, however, is not unduly alarming, for the US oil industry's reserves are very sensitive to the level of oil prices.

***Table 13. Selected Fully Built up Oilfield Costs Outside the OPEC Countries***

| | OIL FIELD name or area | Cost $/bbl |
|---|---|---|
| NORWAY | Equinor's Johan Sverdrup | 12 |
| NIGERIA | Shell's Bonga South West | 27 |
| GUYANA | ExxonMobil's Liza | 22 |
| BRAZIL | Libra sub-salt | 20 |
| US SHALE | N. Dakota (Bakken) | 32 |
| " | Permian (Texas et al) | 35 |
| UK N. SEA | Athena | 35 |
| " | BP's Quad 204 (2017) | 16 |
| CANADA | Oil sands (plus upgrading) | 50 |
| | **Unweighted average** | **28** |

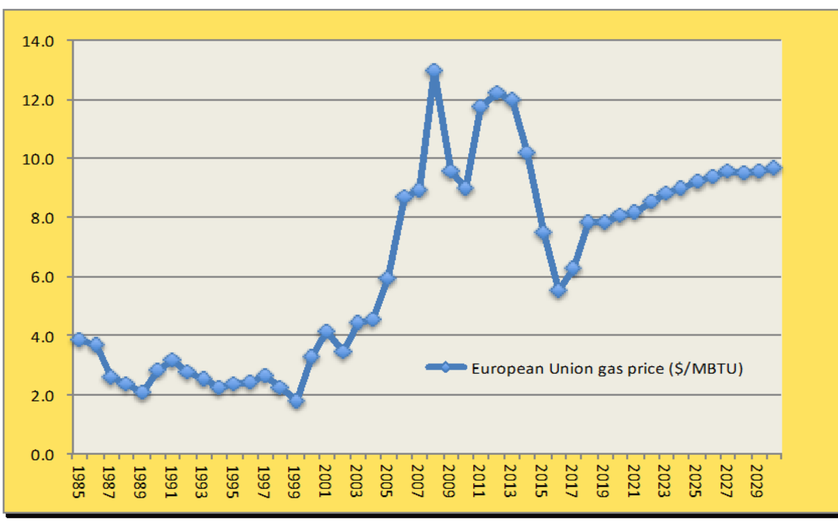
***Source: Author's analysis***

With oil prices in excess of \$60/bbl, as seems likely in the next decade, there is little reason to doubt that US oil reserves and the associated R/P ratios will remain at healthy levels, simply because the fully built up costs of developing US shale oil are not much above \$35/bbl, as shown in Table 4. Indeed, most of the costs displayed in this table are below \$50/bbl and some are very low indeed, like Norwegian oil major Equinor's giant Johan Sverdrup field, according to the very latest information available (World Petroleum Argus, 2019). ExxonMobil's recent Liza development off the shores of Guyana concerns another large field with correspondingly low costs of development, as is Brazil's supergiant Libra oilfield. Finding such low development costs in a wide variety of areas outside the OPEC countries is significant, for it implies that the market price of oil may well not rise above the \$60/bbl level over the next five years at least, unless the members of OPEC, plus a newly found ally like Russia, endeavour to push oil prices higher by cutting their production, as they did in 2017 and are doing again in 2019. To illustrate this point, we need look no further than the massive Permian oil play, the largest in the US. It is currently producing almost 4 mbpd, a level of output exceeded only by Iraq and Saudi Arabia within OPEC; what is more, its output should increase to 5.4 mbpd by 2023, according to IHS Markit, highlighting the dramatic impact of hydraulic fracturing in the largest US oil formation.

## 11.7 Conclusions

We have come almost full circle in our quest to find out what is likely to happen to natural gas prices in the EU with regard to the impressively large natural gas discoveries in the SE Mediterranean. In particular, the question we needed to answer is whether European gas prices will remain at a suitable enough level to make a large investment like the East Med pipeline viable? To help answer such a question we have established (a) that gas prices are correlated with crude oil prices, (b) that gas prices are indeed driven by crude oil prices and (c) that in the short run crude prices themselves are determined by the disequilibrium between desired and actual inventories of crude oil.

***Figure 78. Representative EU Gas Prices in $/mmbtu, 1985 to 2030***




***Sources: BP (2018) and Author's projections***

As for the trajectory of oil prices in the longer term, which will affect the likely path of gas prices in the years to come, it has been ascertained that there is likely to be enough oil to satisfy growing oil demand till the year 2030, without requiring significant increases in the price of crude oil. All that remains for us to do is to obtain from equation (4) forecasts of natural gas prices out to the year 2030, based on our projections of the price of crude oil. These forecasts, which refer to a weighted average of global gas prices, are then pro-rated to yield predictions of natural gas prices in the EU.

As Figure 78 shows, the average price of natural gas in the European Union between 2018 and 2030 is likely to be between \$8 and \$10/mmbtu, unless there is a complete decoupling of gas from oil prices and gas supplies become bountiful in relation to prospective gas demand, which is possible but unlikely in the time frame under consideration. Given that the price of LNG delivered on a CIF basis to Italy at present is around \$8/mmbtu, the implication is that in the years to come the price of natural gas should be at a level that would support continued imports of LNG and, by extension, pipeline gas, from the south eastern Mediterranean. As was pointed out earlier in this chapter, the capital cost of the East Med pipeline, at \$0.69/MBTU, is almost twice that of LNG from the Nile Delta. Yet despite this noticeable discrepancy, the estimated margin of \$4/mmbtu between the fully built up cost of pipeline gas delivered to Italy from the eastern Mediterranean and the likely wholesale price of gas in Italy in the years to come is unlikely to jeopardise the investment in the East Med pipeline. The assumed cost of delivering pipeline gas to Italy from the eastern Med consists of \$0.69/MBTU for the investment, \$0.30/MBTU of operating costs and around \$3.5/MBTU for the cost of the natural gas itself, including a generous profit margin. On this evidence, natural gas from the SE Med should prove to be a plentiful, reliable and relatively inexpensive addition to Europe's gas supplies, in either pipeline or LNG form, until such time as gas itself is no longer required in the Old Continent.

# Conclusion

Over the last years, EU has been increasingly focusing on climate change and has taken several steps towards the creation of a ‘carbon-free’ reality. The use of Renewable Energy Sources experienced a significant growth rate which is projected to increase over the upcoming years. Yet, despite this significant penetration of RES, coal still holds a considerable place in the energy mix. As a result, the existence of an alternative fuel source during this transition period is of great importance. In this context, natural gas has emerged as the ideal transition fuel and is expected to play a crucial role in the energy markets over the following decades.

Given that the majority of natural gas imports originates from a sole supplier, Russia, thus creating energy security issues, the EU has been exploring new routes and sources of natural gas. The Southern Gas Corridor (SGC) is one of the most important EU-wide projects that has been anticipated for long and its completion is approaching fast.

The SGC project involves multiple countries in the SE Europe and attempts to form a transport hub for natural gas from the Caspian region, and potentially the Middle East and Eastern Mediterranean, through the construction of major pipeline networks and LNG terminals. As a result, it simultaneously offers supply and transit diversification to EU member states and provides another supply gateway to Central EU market through Italy.

The completion of the SGC strategy provides several benefits to the involved countries as it offers them increased energy security while at the same time upgrades their importance. Moreover, the existence of an alternative route of natural gas to Europe, creates the opportunity for other non-EU countries, such as Azerbaijan, to export their gas volumes and thus further diversify the gas suppliers of the market.

Overall, the upcoming completion of SGC is expected to have a positive effect over the whole EU gas market. Combined with the recent LNG developments, construction of new LNG terminals and expansion of the existing ones, SGC can assist in decreasing EU’s dependency on Russian gas and thus increase security of supply. Moreover, it will present a great opportunity for SE European countries to upgrade the role of their energy markets, and possibly create a new natural gas hub in the region.

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