IENE
INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE

Prospects for the Establishment of Gas Trading Hubs in SE Europe

An IENE Study Project (M49)

Final Report

Athens, November 2019

PROSPECTS FOR THE ESTABLISHMENT OF GAS TRADING HUBS IN SE EUROPE

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Abbreviations and Units

ACER	Agency for the Cooperation of Energy Regulators
ANRE	Romania's Regulatory Energy Authority
APX	Amsterdam Power Exchange
ATHEX	Athens Stock Exchange
BBL	Balgzand Bacton (pipe)Line
BBSPA	Balkan and Black Sea Petroleum Association
BEH	Bulgarian Energy Holding
BRM	Romanian Commodities Exchange
BRUA	Bulgaria-Romania-Hungary-Austria gas pipeline
bcm	billion cubic metres
CAM	Capacity Allocation Mechanism
CWD	Capacity Weighted Distance
CEE	Central Eastern Europe
CEER	Council of European Energy Regulators
CEF	Connecting Europe Facility
CEGH	Central European Gas Hub
CEGHIX	Central European Gas Hub Index
CMP	Congestion Management Procedures
CNPC	China National Petroleum Corporation
CROPEX	Croatian Power Exchange
DSO	Distribution System Operator
DESFA	Hellenic Gas Transmission System Operator
ECRB	Energy Community Regulatory Board
EEPR	European Energy Programme for Recovery
EEX	European Energy Exchange
EFET	European Federation of Energy Traders
EGEX	European Gas Exchange
EGPC	Egyptian General Petroleum Corporation
EIA	Energy Information Administration
EMGF	Eastern Mediterranean Gas Forum
ENTSO	European Network of Transmission System Operators
EPİAŞ	Energy Stock Exchange Istanbul
EUA	European Union Allowance
EUROPEX	Association of European Energy Exchanges
EXAA	Energy Exchange Austria
FID	Final Investment Decision
FSRU	Floating Storage and Regasification Unit
GBP	German Border Price
GDP	Gross Domestic Product
GPL	Gaspool Balancing Services hub
GTM	Gas Target Model
GTS	Gasunie Transport Services
GWh	Gigawatt hour
HEnEx	Hellenic Energy Exchange

HRADF	Hellenic Republic Asset Development Fund
HTP	Hellenic Trading Point
IBEX	Independent Bulgarian Energy Exchange
ICE	Intercontinental Exchange
IEA	International Energy Agency
IEM	Internal Energy Market
IENE	Institute of Energy for SE Europe
IGB	Interconnector Greece-Bulgaria
IGI	Interconnector Greece-Italy
IGNM	Interconnector Greece-North Macedonia
IMF	International Monetary Fund
IOC	International Oil Companies
IP	Interconnector Point
ISO	Independent System Operator
ITGI	Interconnector Turkey-Greece-Italy
ITO	Independent Transmission Operator
JCPOA	Joint Comprehensive Plan of Action
km	Kilometres
KWh	Kilowatt hour
LNG	Liquefied Natural Gas
m	metres
MAGI	Month Ahead Italian Gas Index
mcm	million cubic metres
MENA	Middle East and North Africa
MIBEL	Iberian Electricity Market
MMbtu	Million British Thermal Units
MoU	Memorandum of Understanding
MRC	Multi-Regional Coupling
MSs	Member States
NBP	National Balancing Point
NC	Network Code
NCG	Netconnect Germany
NEMO	Nominated Electricity Market Operator
NNGS	National Natural Gas System
NNGTS	National Natural Gas Transmission System
NOC	National Oil Corporation
NRA	National Regulatory Authority
NTS	National Transmission System
NYMEX	New York Mercantile Exchange
OIES	Oxford Institute for Energy Studies
OKTE	Short-term Electricity Market Operator
OMI	Iberian Market Operator
OTC	Over the counter
OTSP	Organized Wholesale Natural Gas Sales Market
PCI	Project of Common Interest
PCR	Price Coupling of Regions

PEG	Point d'Echange de Gaz
PEGAS	Pan-European Gas Co-operation
PETFORM	Petroleum and Natural Gas Platform Association
RONI	Regulatory Office for Network Industries
ROPEPCA	Romanian Petroleum Exploration and Production Companies Association
RPM	Reference Price Methodology
PSV	Punto di Scambio Virtuale
RAE	Regulatory Authority for Energy
RES	Renewable Energy Source
SAP	System Average Price
SCP	South Caucasus Pipeline
SEE	South East Europe
SGC	Southern Gas Corridor
SOCAR	State Oil Company of the Azerbaijan Republic
SRMC	Short-run Marginal Cost
TANAP	Trans-Anatolian Pipeline
TAP	Trans-Adriatic Pipeline
TAR NC	Tariff Network Code
tcm	trillion cubic metres
TP	Transparency Platform
TPA	Third Party Access
TRF	Trading Region France
TSO	Transmission System Operator
TTF	Title Transfer Facility
TWh	Terrawatt hours
UAE	United Arab Emirates
UEEX	Ukrainian Energy Exchange
UGS	Underground Gas Storage
VTP	Virtual Trading Point
WLGP	Western Libya Gas Project
ZEE	Zeebrugge gas hub
ZTP	Zeebrugge Trading Point

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Study Sponsors

Executive Summary

The European gas sector is facing major challenges affecting the way natural gas is traded and priced. Oil indexation is the dominant pricing mechanism, but is currently under increasing pressure as trading is gradually shifting to indexation on hub market prices. Gas hubs are virtual or physical locations where buyers and sellers of gas can meet and exchange gas volumes. In other words, gas hubs are marketplaces for natural gas.

The Institute of Energy for South-East Europe (IENE) took the initiative and carried out a research project, based on an earlier IENE study M19 (September 2014) on "The Outlook for a Natural Gas Trading Hub in SE Europe" **(1)**, in order to examine the conditions and prospects for establishing a gas hub in SE Europe. At present, there is neither a market mechanism to buy or sell gas in an efficient manner in the SE European region, nor a price discovery mechanism to determine spot prices, and gas exchange is based on bilateral agreements.

Today, there are 14 gas trading hubs operating across Europe. According to the International Gas Union, gas-on-gas competition in Europe increased from 15% in 2005 – when oil price escalation was 78% - to 76% in 2018 – when oil price escalation had declined to 24% **(2)**. Liquidity is increasing in European trading hubs, while the European Union aims at further increasing of liquidity, in the context of the completion of an integrated and interconnected internal energy market. The integration is expected to increase the energy market effectiveness, create a single European gas and electricity market, contribute in keeping prices at low levels, as well as increase security of supply. Trade between EU member states will become more flexible and thus, possible curtailments of Russian supplies will have less impact on the European gas market.

Oil-indexed prices have been associated mainly with long-term contracts while hub prices have been associated with spot or short-term contracts. Oil-indexed long-term contracts prevailed in the gas sector because they were considered to ensure investment security for the producer as well as security of supply for the consumer. On the other hand, a gas price mechanism which reflects the market value of the product should be considered as a natural evolution for the pricing of a commodity. Indeed, long-term contracts with prices linked to a gas market would ensure a price level reflecting the balance of supply and demand of the product in addition to security of supply.

Europe sees an important opportunity to meet its energy needs by developing the Southern Gas Corridor, at the core of which are gas supplies from the Caspian area (including Azerbaijan and most likely in the far future from Turkmenistan, Kazakhstan and Iran) and possibly from the Middle East (Iraq). The SE European countries (i.e. Greece, Croatia, Bulgaria, Romania, Turkey and Serbia) have well established gas markets, with supplies coming primarily through imports from Russia and, in the case of Turkey, from Iran and Azerbaijan also. Greece and Turkey, which have well developed LNG import and storage terminals, also import from Algeria, Nigeria, Qatar and other LNG spot markets. Two countries have a significant proportion of their demand met from domestic supplies (i.e. Croatia and Romania) and three others cover small percentage shares from domestic gas (i.e. Bulgaria, Serbia and Turkey).

According to IENE forecasts, some marginal gas quantities will become available after 2020 in the SE European region, which could be traded and therefore, as far as trading is concerned, the need will emerge for market prices to be determined. Turkey is already a major gas importer from Russia, Iran and Azerbaijan. In the future, Turkey is likely to get gas from Iraq. In addition, LNG will be another important player in the market, as there are plans for new LNG import terminals in the region. Already, one FSRU[1] is planned to be based in Alexandroupolis in Northern Greece, with the prospect of feeding gas quantities into the Greek and Bulgarian natural gas systems, among others. The Trans-Anatolian Pipeline or TANAP, already in operation since June 12, 2018, will be connected to Greece through the Trans-Adriatic Pipeline (TAP) pipeline, which is now under construction and about 91% completed as of October 2019. In addition to Azeri gas, TAP could be used to transport North African gas to Southern Europe and Turkey via reverse flow. There will also be a connection between Greece and Bulgaria and Bulgaria to Turkey via new interconnector pipelines. The immediate result of all of this is that there will be certain gas quantities available for trading outside long-term contracts. Consequently, the establishment of a natural gas trading hub initially to enable trading between Greece, Bulgaria and Turkey, will ensure the determination of market prices through the exchange of marginal gas volumes.

A hub can be a physical point, at which several pipelines come together (e.g. Zeebrugge) or it can be a virtual (balancing) point inside a pipeline system (like the NBP). In other words, a *physical hub* is an actual transit location or physical point where gas pipelines meet and natural gas is traded. Physical hubs can serve as transit points for the transportation of natural gas, as well as storage facilities. Nonetheless, a hub does not need to be a physical intersection of pipelines.

A *virtual hub* is a trading platform for the financial transaction of natural gas, where a wide number of participants have access. Physical hubs are implemented at a specific location where natural gas must imperatively be transported to. However, in the case of virtual hubs, the trading platform serves a trans-regional zone or an entire country. Therefore, the traded gas can be injected into any point on a trans-regional or national grid regardless of the point of extraction. The obvious advantage of virtual hubs is that all gas which has paid a fee for access into the network can be traded, while at physical hubs, only gas physically passing at a precise location can be traded and this entails higher risks.

Virtual trading hubs, such as NBP or TTF, do not yet exist in Southern and Eastern Europe. The region is now starting to warm up to the prospect of a liquid market where long-term contracts and spot or short-term trading are combined. The establishment and functioning of a gas trading hub requires a deregulated gas market, which is not the case today in most countries of SE Europe.

However, one could argue that the operation of a physical transit regional hub, such as the Belgian Zeebrugge, could also be possible, due to the flexibility resulting from the operation of the existing and planned interconnections in the region. The region could serve as a transit route for carrying Azerbaijani gas to smaller hubs that are planned in the region, as well as the Central European Gas Hub in Austria. Like the Zeebrugge, a hub where pipelines

[1] A Floating Storage Regasification Unit (FSRU) is a special type of vessel which is used form transporting LNG.

physically meet, a regional hub storage and LNG facilities, as well as pipeline connections, could become a possible balancing point for both storage and transportation.

A virtual hub would offer even greater flexibility, because – as it has already been mentioned – in virtual hubs, the eligible gas for trading is all the gas which has paid a fee for access into the network. Especially when moving towards an entry-exit system – which is required by EU regulation for member states - virtual hubs are more suitable for gas trading.

The establishment of a regional natural gas hub is expected to facilitate the wholesale trading of natural gas between participants in SE Europe. Essentially, it will allow gas supply and demand to meet in a marketplace by providing a platform for physical and/or financial transaction. It will enable competitive markets to function, even though it will probably have an administrative role in the beginning of its operation.

An important issue to be addressed is where the gas hub will be based. Increased supply optionality and infrastructure development are prerequisites for creating a market in the region. At the moment, there are several new pipeline connections planned in SE Europe, as well as FSRU and underground gas storage facilities, with Greece, Bulgaria and Turkey having expressed a high interest in establishing a regional gas hub.

Storage will also play an important role in providing physical gas flexibility. The role of gas storage is critical as it can serve as an important flexibility tool and may affect the location of the hub, if physical. If the hub operates as a physical hub, it is possible that the TAP/IGB/IGT junction can serve as a physical hub. In this respect, the creation of an underground gas storage facility in South Kavala is key, especially if Greece is to take a lead role in this initial stage.

1. Introduction – Raison d' être

Europe's dependence on imported natural gas has grown over the past 10 years. Based on Eurostat's data, gas demand in the EU rose by 5% in 2017, compared to the previous year and the increase was mainly driven by increased gas-fired electricity generation. The EU imported 76% of gas in order to cover its needs, mainly from Russia, Norway and Algeria, while LNG imports stood at 12% higher in 2017 than in 2016. Domestic production continued to decline and reached 24% of EU consumption.

Figure 1: European Union: Net Gas Imports (Left Axis) and Import Dependency (Right Axis), 2008-2017

Source: Eurostat

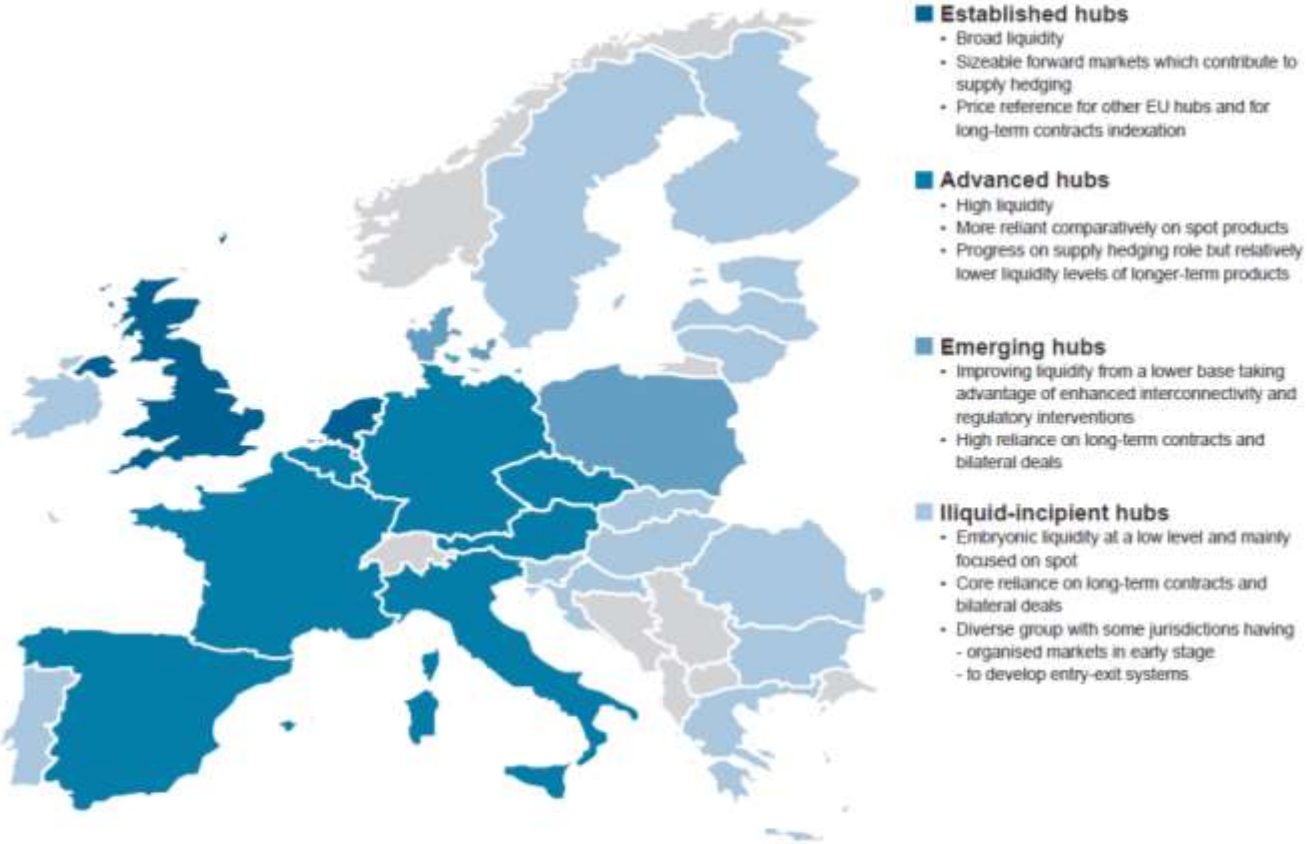
In 2017, the total EU hub-traded volumes were around 3% lower (i.e. 44,500 TWh or 4,555 bcm), compared to 2016, which is explained by lower price volatility at the largest gas hubs (i.e. TTF, NBP and NGC). However, other hubs saw an increase in trade. Gas prices also recovered from lower values in 2016, e.g. North West Europe (NWE) hubs' day-ahead prices were 20% higher than in 2016. In 2017, hub price purchases accounted for around 70% of supplies across Europe, with differences between regions. **(3)**

European gas wholesale markets continued to show increasing levels of convergence in 2017, in terms of gas hub prices (although to a lower extent for the latter due to the absence of hubs in a number of EU member states). More specifically, gas hubs in northwest Europe registered the highest price convergence in the EU, because of similar market fundamentals, ease of access for upstream suppliers, stable increase in hub trading, relatively lower-priced cost of transportation capacity and surpluses of long-term contracted capacity and commodity. Price integration in the Central and Eastern European region has improved in recent years, while Mediterranean hubs showed lower convergence. This is due, among other things, to lower interconnection capacity levels, the pancaking of transportation tariffs and weaker hub functioning.

Britain's National Balancing Point (NBP) and the Dutch Title Transfer Facility (TTF) continue to be the EU's best functioning gas hubs. TTF and NBP distinguish themselves from the other hubs mainly because of the higher development of their forward markets (e.g. traded volumes on the curve, longer trading horizon, tighter bid-ask spreads). Over the last two years, TTF has overtaken NBP both in volumes traded and in its role as price-setter in Europe.

The difference between better functioning hubs and those without transparent trading venues continues to increase. Map 1 presents a classification of gas hubs. The groupings reflect the results of the ACER Gas Target Model (AGTM) metrics analysed in its Market Monitoring Report (MMR)[2]. While there are notable positive developments in the Iberian and Baltic regions, those EU member states where a trading venue with a transparent price mechanism is either absent or not visible during many trading days of the year continue to fall behind better performers. These EU member states will find it harder to catch up as the difference becomes bigger and bigger. The Energy Community Contracting Parties[3] still show very limited hub trading activity.

Map 1: Ranking of EU Hubs Based on Monitoring Results - 2018



Source: ACER

[2]https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202018%20-%20Gas%20Wholesale%20Markets%20Volume.pdf

[3] Currently, the Energy Community has nine Contracting Parties, including Albania, Bosnia and Herzegovina, Kosovo, North Macedonia, Georgia, Moldova, Montenegro, Serbia and Ukraine.

The present study aims to examine the role of a gas trading hub in SE Europe, to identify the conditions and requirements for its creation which will initially operate as a regional balancing point and eventually as a fully-fletched gas trading hub, as well as to analyze the economic and political implications of the trading activity of the hub for the SE European countries.

This study focuses on the requirements for the establishment of a gas trading hub that will allow for gas prices to reflect local demand and supply. In **Chapter 2**, there is a review of the existing gas trading hubs in Europe, while the European energy exchanges and their role in promoting gas trade are both presented in **Chapter 3**. In **Chapter 4**, the perspectives for existing and potential suppliers of European gas market and their role in market liquidity are examined, while the profile of SE Europe as a gas transit region is analyzed in **Chapter 5**. The role of key regional gas players is assessed in **Chapter 6**, as well as their ability to support a competitive natural gas market. In **Chapter 7**, the role of Central European Gas Hub (CEGH) is highlighted as a benchmark and pivot for promoting gas trading activities in SE Europe, while **Chapter 8** focuses on the ascendance of Hellenic Trading Point (HTP), Greece’s gas trading hub, in the broader Central and South East European region. **Chapter 9** provides a view of the economic implications from the operation of a gas trading hub in the region, while **Chapter 10** summarizes the conclusions of the study.

2. European Gas Trading Hubs

2.1. Introduction

During the last decades, there have been important changes in the European natural gas markets. European gas hubs are young and less developed compared to US gas hubs. The Henry Hub in Louisiana sets the benchmark price for the entire North American trading area, which is the most liquid gas market in the world. Currently, the European gas market is characterized by long-term contractual arrangements with gas producers (often outside of the EU), for the delivery of specific gas volumes at specified points on natural gas transmission networks. Since deregulation in the mid-1990s and as a result of the gradual opening of gas markets in several European countries, trading has started gaining ground and spot markets have developed. However, long-term contracts are still the dominant feature. The number of participants and traded volumes are increasing along with the traditional OTC volumes.

The European Union promoted the establishment of virtual (regional) trading hubs in order to achieve the integration of its natural gas markets. According to the old market regime the ownership exchange of natural gas is arranged in a bilateral fashion between the buyer and the supplier using long-term contracts. Market experience shows this market model will gradually be replaced by wholesale markets where sellers and buyers make short to medium - term deals through trading hubs. These deals now include futures, swaps, and even a few options.

The new market model does not include the creation of a single European regulator. To the contrary, its philosophy is to build on the existing contractual, regulatory and operational arrangements of national TSOs and regulators and facilitate the efficient use of cross-border capacity with transparent price formation, which will encourage greater participation in trading and increase liquidity.

The National Balancing Point (NBP) in the UK is the oldest and most liquid gas hub in Europe (1996). Due to gas liberalization policies carried forward by the European Union and mergers between different gas hubs (for example, between France and Germany), market pricing of gas contracts has become increasingly important in continental Europe, particularly since the pipelines connecting UK's NBP to Belgium's Zeebrugge hub and to the Dutch Title Transfer Facility (TTF) started operation. During the previous decade, market pricing was launched in the rest of Europe through interconnecting pipelines, while new gas hubs were created.

Table 1: Evolution of European Gas Traded Hubs (as of 2018)

Gas Traded Hubs	Date
NBP	National Balancing Point; Great Britain; 1996
ZEE/ZTP	Zeebrugge Hub/Zeebrugge Trading Point; Belgium; 2000/2012
TTF	Title Transfer Facility; Netherlands; 2003
PSV	Punto di Scambio Virtuale; Italy; 2003
PEG (N,S,T)/TRS/TRF	Points d' Echange de Gaz (Nord, Ouest, Est, Sud, TIGF); France: 2004 PEG Nord (merger of PEGs N,O,E); France: 2009 Trading Region South (covering PEG Sud and TIGF); France: 2015 Trading Region France (covering PEG Nord, Sud and TIGF); France: 2018
AOC/PVB	Almacenamiento Operativo Comercial/Punto Virtual de Balance; Spain; 2004/2015
GTF/ETF	GasTransfer Facility/Electronic Transfer Facility; Denmark; 2004
CEGH/VTP	Central European Gas Hub/Virtual Trading Point; Austria; 2005/2013
GPL	Gaspool; Germany; 2009
NCG	NetConnect Germany; Germany; 2009
MGP	Magyar Gázkiegyenlítési Ponton; Hungary; 2010
VOB	Virtuální Obchodní Bod; Czech Republic; 2011
VPGS	Virtual Point Gaz-System; Poland; 2014
SK (VOB)	Slovenskom Virtuálnom Obchodnom Bode; SK; 2016

Source: Heather, P. (4)

Map 2: European Gas Regions, Markets and Hubs (as of 2018)

Source: Heather, P.

2.2. Gas Trading

In order to understand the basics of natural gas trading, it is important to make a distinction between the types of hubs and the types of markets offered at hubs.

2.2.1. Physical VS. Virtual Hubs

A hub can be a physical point, at which several pipelines come together (e.g. Zeebrugge) or it can be a virtual (balancing) point inside a pipeline system (like the NBP). In other words, a ***physical hub*** is an actual transit location or physical point where gas pipelines meet and natural gas is traded. Physical hubs can serve as transit points for the transportation of natural gas, as well as storage facilities. Nonetheless, a hub does not need to be a physical intersection of pipelines.

A ***virtual hub*** is a trading platform for the financial transaction of natural gas, where a wide number of participants have access. Physical hubs are implemented at a specific location where natural gas must imperatively be transported to. However, in the case of virtual hubs, the trading platform serves a trans-regional zone or an entire country. Therefore, the traded gas can be injected into any point on a trans-regional or national grid regardless of the point of extraction. The obvious advantage of virtual hubs is that all gas which has paid a fee for access into the network can be traded, while at physical hubs, only gas physically passing at a precise location can be traded and this entails higher risks. Nevertheless, for a virtual hub to be effective, its gas traded volumes need to be proportionally backed by the existence of adequate gas physical quantities and in the vicinity of the location of the gas hub.

The Oxford Institute for Energy Studies (OIES) uses an alternative approach for the distinction of EU gas hubs into categories, based on their market development **(5)**. According to this approach, they can be classified as: trading, transit and transition hubs. *Trading hubs* are mature hubs which allow the participants to manage gas portfolios. *Transit hubs* are physical transit points where natural gas is physically traded, the main role of which is to facilitate the onward transportation of gas. *Transition hubs* are virtual hubs which are relatively immature, but have set benchmark prices for natural gas in their national markets.

The emergence of hubs promoted the development of gas exchanges. Services provided by gas exchanges may include spot trading on day-ahead and intra-day markets, forward markets and variable derivatives. The different locations of gas exchanges are presented in the map below. These exchanges also trade in other commodities, such as electricity and coal.

2.2.2. Exchange Based-Trading VS. Over-The-Counter (OTC) Trading

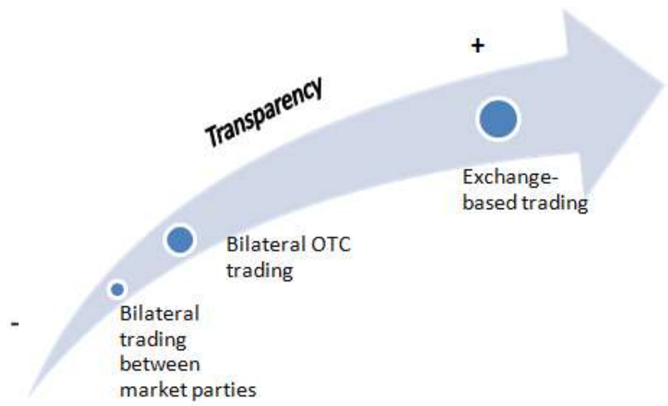
Natural gas trading takes place either bilaterally, in over-the-counter (OTC) markets, or centrally on an exchange.

An ***over-the-counter market*** does not use a centralized trading mechanism i.e. a shared platform to aggregate bids and offers and allocate trades. OTC trades are bilateral non-regulated deals in which buyers and sellers negotiate terms privately, often not being aware of the prices currently available from other potential counterparties and with limited knowledge of trades recently negotiated elsewhere in the market. OTC trading can be based on standard as well as customized products. **(6)**

Exchange-based trading is based on standardized products defined by their time of delivery. The delivery date can extend from days to several years in the future, provided that there is sufficient liquidity in the market. The further ahead the date of delivery is the more liquid the market is considered to be. Both in OTC markets and exchanges a spot market and a futures market can operate. In the spot market, delivery is immediate. It contrasts with the future markets where delivery is due at a later date and can possible extend years ahead. **(7)**

A basic difference between OTC trading and exchange trading is that trading on the exchange takes place anonymously and the counterparty risk is managed by the exchange i.e. the exchange – or its clearing house - guarantees that the other side of the transaction performs to its obligations[4]. Exchange-based trading also increases transparency in the natural gas market through the price signals it provides.

Figure 2: Transparency on Bilateral and Exchange-Based Trading



Source: IENE (2014)

OTC is still the favored trading method on gas hubs. The main advantages of OTC trading are the lower costs (e.g. it does not include clearing fees) and customized products which are widely used by suppliers to accommodate each consumer's requirements for timing, volume, etc. Transactions are clearer and safer on exchanges but their fees can often be prohibitive for small companies. Exchanges require a high level of standardization and liquidity in the products traded and this can reduce the ability of many energy providers to find the customized products they need in order to manage their risks. According to ICIS, traders report that OTC trading is more flexible if the market participant mis-trades because the error can be corrected by a broker in 2 minutes. On the other hand, writing off a loss can be more complicated on exchanges. Furthermore, pricing interference on exchanges from regulators and market designers is not uncommon and the anonymity offered by exchanges is not always inviting because some companies like to know who the counterparty is. **(8)**

[4] It should be noted that it is possible for a market participant to insure itself against counterparty risk through clearing houses; however, this diminishes the cost advantage of OTC trading, compared to exchange-based trading.

However, the share of exchange trading has been constantly increasing and therefore, exchanges are expected to continue to develop and play an important role in natural gas trading in Europe, alongside the OTC trading.

Table 2: Differences Between Exchange-Traded and OTC – Traded Products

	Exchange-traded products	OTC-traded products
Pricing	Standardized	Customized
Quantity	Standardized	Customized
Maturity	Standardized	Customized
Quality	Standardized	Customized
Documentation	Standardized	Customized
Risk	Market risk	Market risk & Counterparty risk

Source: IENE (2014)

2.3. Overview of European Gas Trading Hubs

The last decade has seen clear progress in the development of the European gas trading hubs although with some very different results across Europe in terms of speed of development and the level of development. European gas trading hubs offer a variety of contracts and services and this section will describe in detail the majority of them individually.

2.3.1. UK National Balancing Point (NBP)

The UK NBP gas market started operation in 1996 and is Europe's longest-established natural gas market and most liquid gas trading point. Pricing at this trading point is often compared to Henry Hub[5] in the US, which is the trading point for the New York Mercantile Exchange (NYMEX) natural gas futures contracts. It is operated by the National Grid, the transmissions system operator in the UK. However, the NBP is not an actual physical location, but a virtual trading location. Trades at the NBP are made via the OCM (On-the-day Commodity Market) trading system, a trading service managed by ICE-Endex to which offers or requests for gas at a nominated price can be posted. ICE-Endex is the counterparty to *every* trade in the OTC market and is responsible for nominating the trades to National Grid, the British Transmission System Operator (TSO). In the prompt market, companies need to perform the nomination by themselves. Companies who have not become Shippers[6] in order to trade, can only trade NBP on the ICE futures.

The UK NBP price reflects the commodity price in the entire area, as there are no geographic differentials. This occurs because transport costs are levied separately by the TSO i.e. National Grid, the system operator for Britain's gas National Transmission System (NTS), that runs the British gas network and is regulated by the British energy regulator (Ofgem). The NBP price acts as an indicator for Europe's wholesale gas market, alongside the Dutch TTF. With its four LNG terminals and established market, the NBP is also used as an indicator for

[5] The Henry Hub, owned by Sabine Pipe Line LLC, is a distribution hub at Erath in Louisiana that connects many intrastate and interstate pipelines. The settlement prices at this hub are used as benchmarks for the entire North American natural gas market.

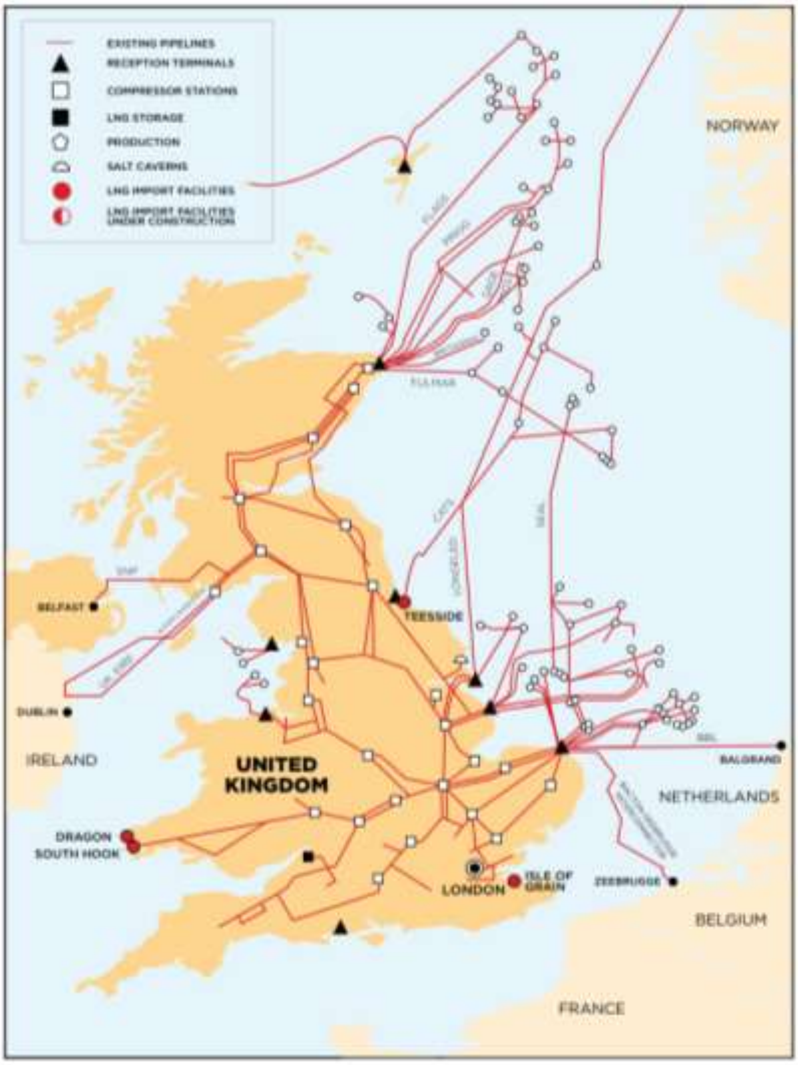
[6] Shippers are commercial players transporting gas in the transmission network.

the European spot LNG market, something no other European hub is likely to achieve currently.

The NBP was created by the Network Code in order to serve the balancing of the system as it is detailed in the Code. The Network Code set out the rules and obligations for accessing the British pipeline grid. On the NBP, shippers are required to nominate quantities entering and/or exiting the network, and not the transport route which the gas should physically follow.

The UK gas market is supplied with gas by the UK's own gas production, imports from Norway and Continental Europe, storage, and LNG tanker supplies from global markets. In physical terms, about half of all gas supplied is traded.

Map 3: UK Gas Transmission System



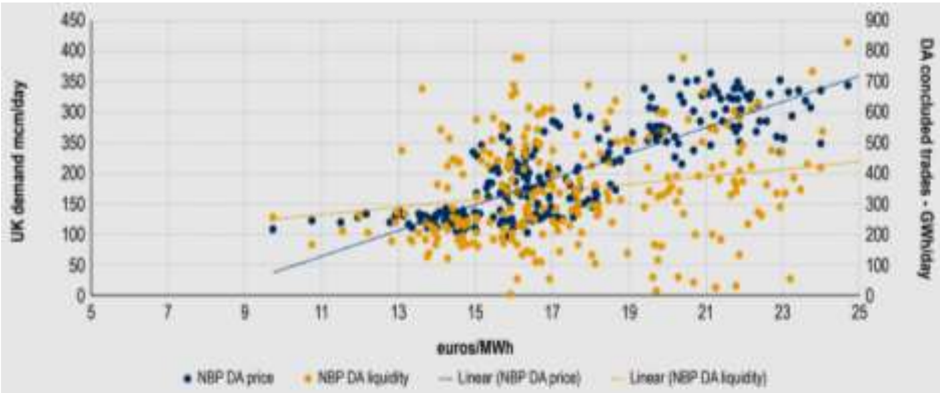
Source: Fulwood, M. (2018) (9)

The price set on the OCM is used as a reference for the System Average Price (SAP), the weighted average price of all trades for the relevant gas day on the OCM platform. Based on the SAP, the System Marginal Buy Price (SMBP) and the System Marginal Sell Price (SMSP) are computed.

On the NBP gas hub, liquidity continued to dry up, with 2018's total of 7,136 TWh; the lowest since at least 2011, while the traded volume of 325 TWh in December 2018 is the lowest for a calendar month in at least seven years. NBP OTC traded volume accounted for a mere 21% of all European OTC transactions in 2018, down from 28% in 2017 and the 61% seen back in 2011.

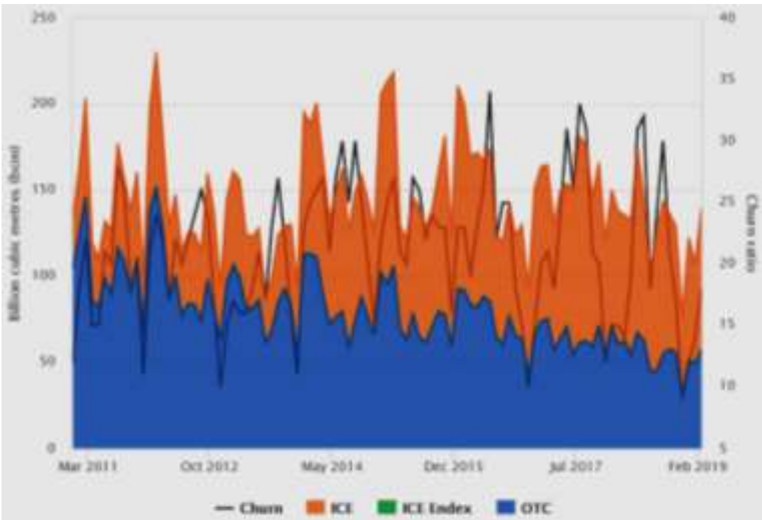
Future trades make the NBP the most liquid European hub. The NBP's churn ratio[7], which is a liquidity indicator, is usually around 20, while it rose to 20.05 in 2016. Gross churn ratio can be calculated as the ratio of total traded volumes at NBP and the country's demand of gas, while the net churn ratio is calculated as the ratio of traded volumes at NBP and the total volume of gas physically delivered at NBP **(10).** Figure 3 reveals how the moves in UK daily demand correlate with changes in NBP prices.

Figure 3: Correlation Between Daily Demand, DA Hub Traded Volumes and DA Hub Prices at NBP – 2017



Source: ACER (2018)

Figure 4: Gas Trading Volumes and Monthly Churn Ratio by Platform at the NBP



Source: Ofgem[8]

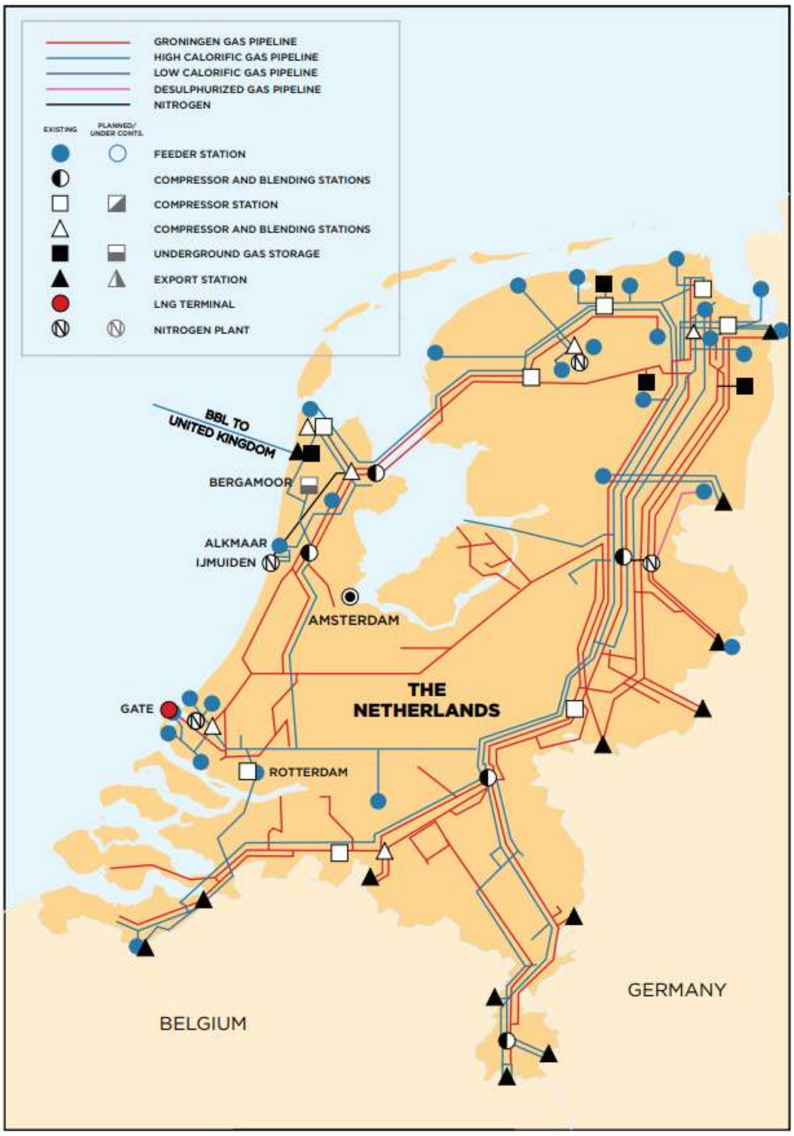
[7] The churn rate describes the ratio between physical transfers and traded volumes at the VTP and is therefore an indicator of trading activity and liquidity within the market area. A churn rate of 10 is considered a threshold of a mature market.

[8] Ofgem (2019), "Gas trading volumes and monthly churn ratio by platform (GB)", https://www.ofgem.gov.uk/data-portal/gas-trading-volumes-and-monthly-churn-ratio-platform-gb

2.3.2. Dutch Title Transfer Facility (TTF)

The Title Transfer Facility (TTF) is a virtual marketplace established in 2003 by Gasunie Transport Services (GTS), in order to facilitate trading in the Dutch natural gas market. With the introduction of the new market model in 2011, the TTF became the central trading point for the entire natural gas in the Dutch transmission system.

Map 4: Dutch Gas Transmission System



Source: Fulwood, M. (2018)

The TTF can serve as a virtual entry point that offers market parties the possibility to transfer gas already present in the GTS system to another market player. It was established in 2003 in order to promote gas trading in one marketplace and increase the liquidity of gas trading. In TTF, a shipper can choose a virtual entry and exit point or can choose not to use TTF and thus, not pay a fee.

The balancing regime introduced in April 2011 renders shippers responsible for keeping their portfolios balanced through buying and selling gas on the TTF. The balancing regime change has therefore contributed in establishing “market-based balancing”. If there are not adequate gas quantities in the network, incentives are given to the shippers to offer operational flexibility. In particular, shippers manage their portfolio balance with regard to the GTS grid balance. A system imbalance appears when the System Balance Signal published by GTS deviates from zero, which means that there is either a positive or a negative imbalance. Imbalances are classified into four zones: dark green, light green, orange and red zone. Shippers have to keep the system price signal on the green zone. Should the signal leave the dark green zone, a correction mechanism known as the Bid Price Ladder mechanism, is put into effect and GTS will buy or sell gas depending on whether there is a shortfall or an excess of gas. This mechanism provides increased availability of market information to shippers.

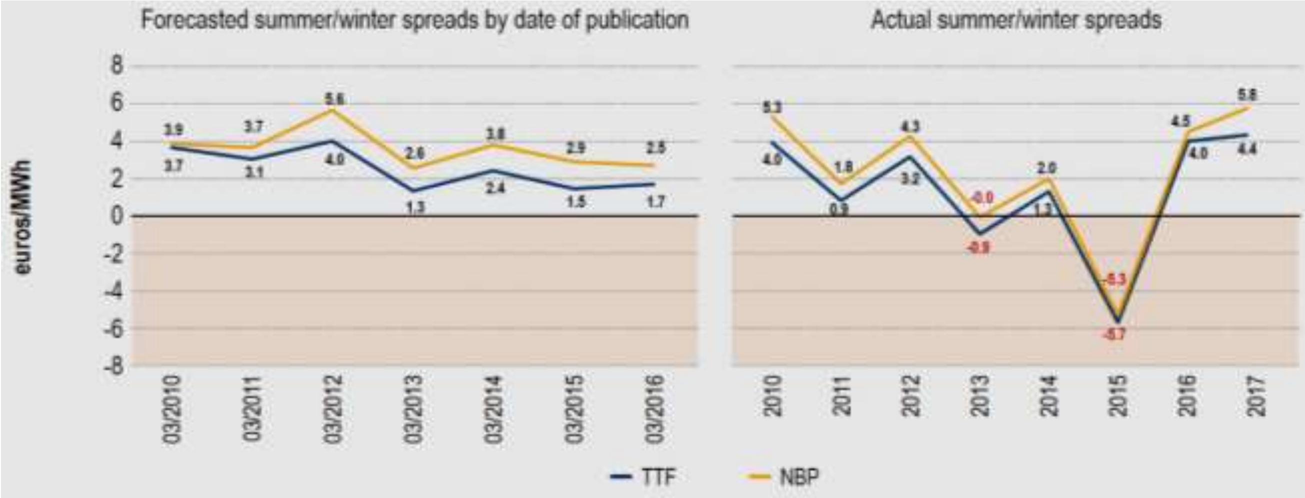
This Dutch gas trading exchange has greatly expanded over the last few years and is now the biggest hub in Continental Europe in terms of traded volume. According to the GTS, the amount of gas traded is more than 14 times the amount of gas consumed in the Netherlands. As a result of its expansion, the gas price of the Dutch wholesale platform has become an important indicator for the European wholesale gas market. Physical short-term gas and gas futures contracts are traded and handled by ICE ENDEX.

TTF's location between Germany, France and the North Sea coast enables it to transfer gas from Norway to the German and French markets. The TTF is also connected to Britain's NBP hub. Additionally, the Dutch LNG terminal, opened in 2011, gives TTF direct access to the global LNG market, an advantage that Germany and Austria both lack.

ICE Endex provides the platform for spot trading at the TTF. The TTF Spot Within-Day and Day-Ahead are tradable spot instruments offered at the ICE Endex platform. The TTF Within-Day Index is a volume-weighted average price of all orders which are executed and delivered on the same gas day on TTF, while the Day-Ahead Index is a volume-weighted average price of all orders which are executed on the gas day preceeding the day of delivery.

Total TTF liquidity for 2018 stood at 21,250 TWh after a total of 1,370 TWh of activity was seen during December, representing an annual increase of 36% and setting a fresh record high for a calendar year in the process. As a result, the TTF hub accounted for 63% of all OTC transactions in Europe in 2018, compared to 54% in 2017 and a mere 28% back in 2011, when the UK's NBP hub was more liquid.

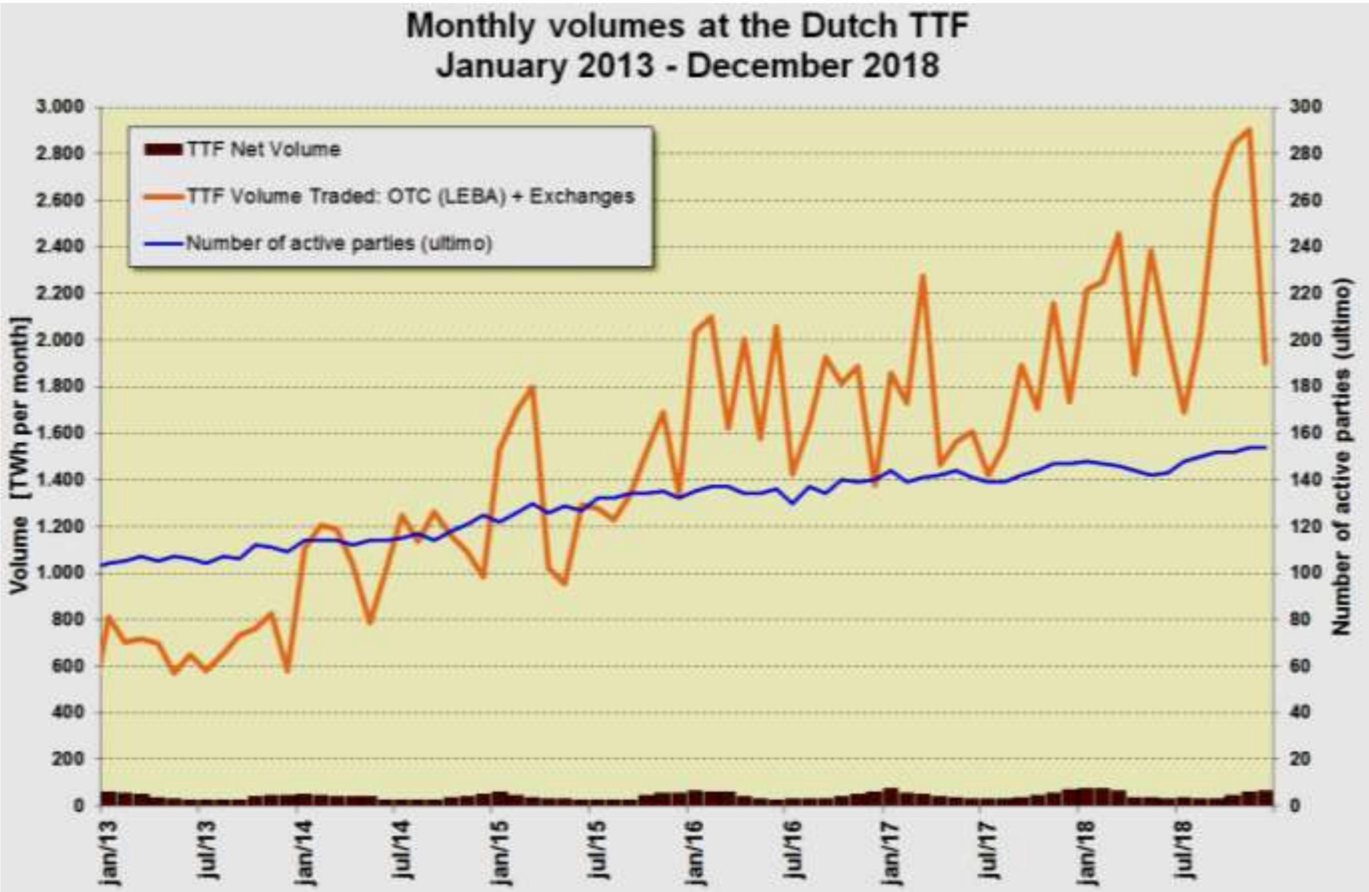
Figure 5: NBP and TTF Forward and Actual Summer/Winter Spreads 2010–2018 - €/MWh



Notes: (1) Ex-ante graph: for every storage year, the forward summer/winter spread is calculated as the difference between the Season+2 prices (covering the period from October "Y" to March "Y+1") and Season +1 prices (covering the period from April "Y" to September "Y"), as observed on average on March "Y". (2) Ex-post graph: for every storage year, the ex-post summer/winter spread is calculated as the difference between the average of the actual spot prices during the period from October "Y" to March "Y+1" and the average of actual spot prices during the period from April "Y" to September "Y".

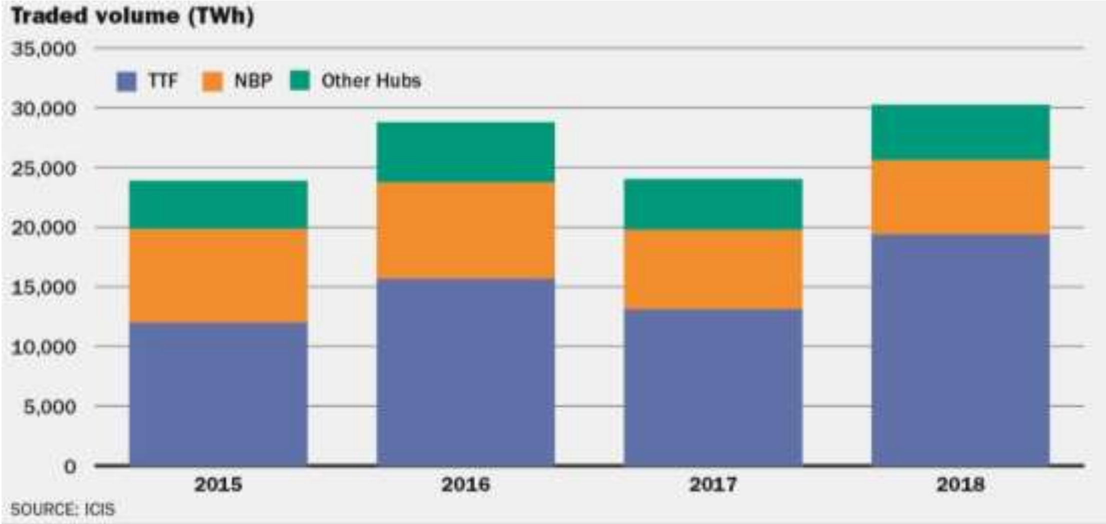
Source: ACER (2018)

Figure 6: Monthly Volumes at the Dutch TTF (January 2013 – December 2018)



Source: Gasunie Transport Services

Figure 7: Total Traded Volumes at the NBP and TTF, 2015-2018



Source: ICIS

2.3.3. Central European Gas Hub (CEGH)

Central European Gas Hub AG (CEGH) is located in Vienna, Austria and is the leading hub for gas trading from the east to the west, since it acts as a hub that transports natural gas imports to Western European countries as well as a link between North West (Germany) and South East markets (Italy). More specifically, trade takes place between Austria and its neighboring countries, which include Hungary, Italy, Slovenia, Slovakia and Germany. Its location allows it to provide German and Italian markets with Russian and Central Asian gas supplies.

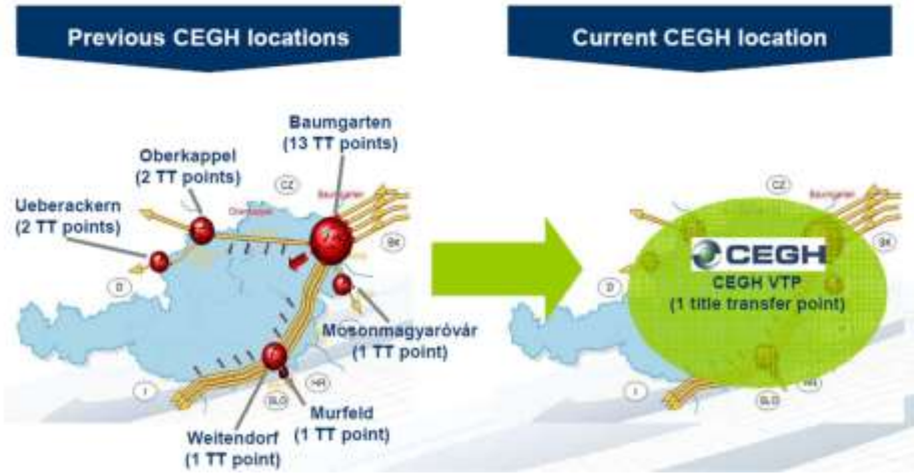
The shareholders of Central European Gas Hub AG are OMV Gas & Power GmbH with a stake of 65%, Wiener Boerse AG with a stake of 20% and Slovak Eustream a.s. with a stake of 15%. CEGH developed the gas exchange in co-operation with Wiener Börse AG, and European Commodity Clearing AG (ECC).

CEGH cooperates with several different TSOs, particularly in Baumgarten, OMV's main gas compressor station (OMV, TAG, BOG, Eustream). Approximately one third of all Russian gas exports to Western Europe are handled via Baumgarten. CEGH plays a significant role in continuously matching all trading activities, as well as integrating them between these networks and connecting them via wheeling services.

The CEGH Gas Exchange is divided into the spot market (CEGH Gas Exchange Spot), which started operation in late 2009 and the futures market (CEGH Gas Exchange Futures), which started operating in late 2010. CEGH is already one of the biggest gas hubs in Continental Europe, and prior to launching the spot market there were already 90 registered traders using CEGH for over the counter (OTC) trading amounting to 2 bcm of natural gas per month.

The Market Model in Austria changed to an Entry/Exit System on the 1st of January 2013, as a result of the implementation of the 3rd EU Energy Package. Gas transportation is executed via entry and exit points, independent from transport routes, as opposed to point-to-point transportation. The transportation contracts and capacity management are carried out by the respective TSO. The market area in the east of Austria turned into one single zone in terms of transport, supply and storage activities integration. Additionally, the different trading locations in Austria turned into one Virtual Trading Point (VTP), operated by CEGH. Its primary role is to facilitate trading and to source gas for onward operators. CEGH offers trading services for three different markets: OTC trading, the spot market, and the futures market.

Map 5: Introduction of the CEGH VTP and Consequences for CEGH Title Transfer Points (TTPs)



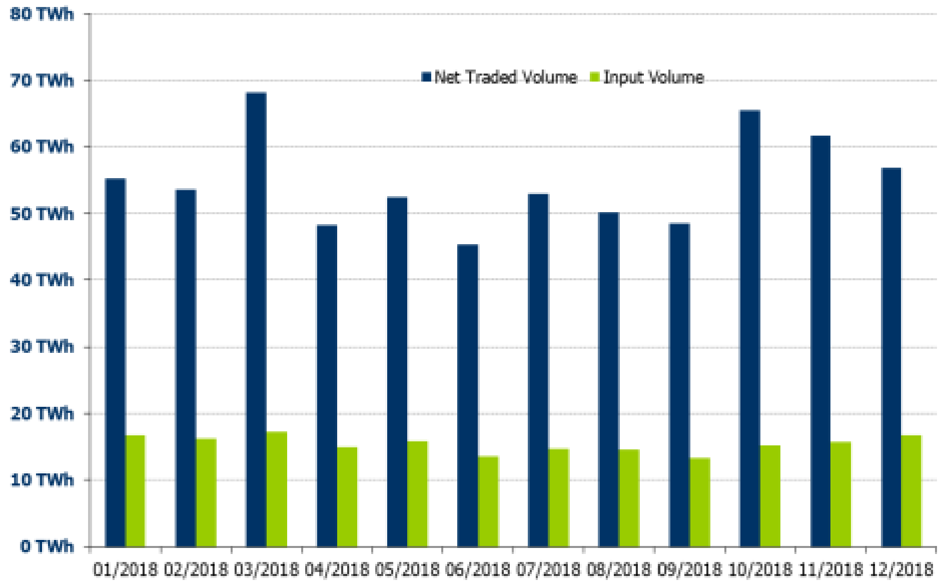
Source: CEGH

The hub in Austria consists of three separate networks, known as Market Areas. The main balancing zone, located in the east of Austria, has a high-pressure transmission grid and a high- and low-pressure distribution grid. The two smaller networks are located in the west central (Tirol) and western (Voralberg) Austria. They are not physically connected to the Eastern Area, or to each other, but they are connected to Germany.

The spot index CEGHIX, published by CEGH, serves as reference price for the Gas Exchange Spot Market. It guarantees a daily reference price based on the volume weighted average price of all transactions. The Gas Exchange products for the Austrian and Czech markets are offered on the PEGAS platform in cooperation between Powernext and CEGH. PEGAS is the pan-European gas trading platform of Powernext. Powernext and CEGH have established the PEGAS CEGH Gas Exchange Services GmbH in 2016 as joint subsidiary, which supports the Austrian, Czech and CEE gas markets.

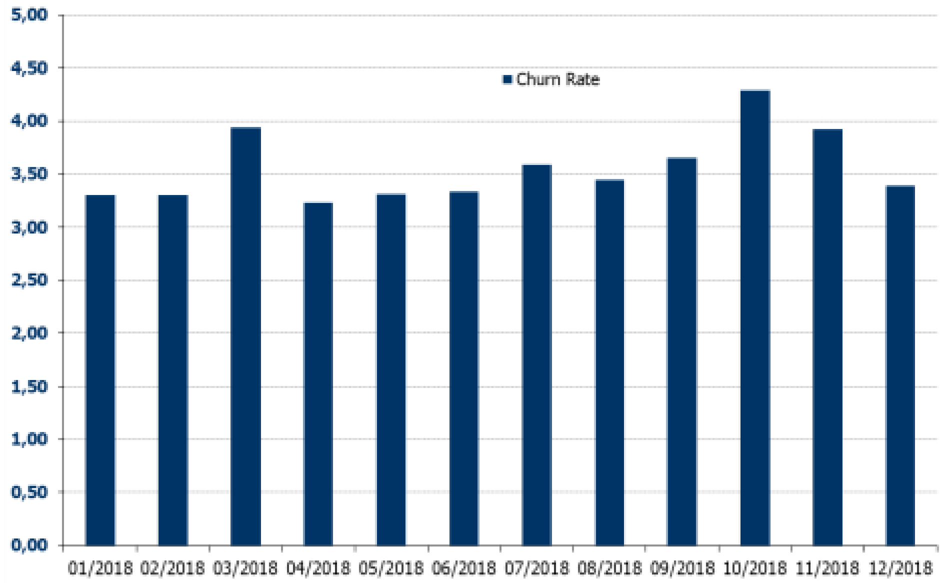
In 2018, CEGH established itself as one of Central Europe's leading trading platforms when it achieved a nominated volume of 659 TWh of natural gas at the CEGH VTP. Figures 8 and 9 present the evolution of CEGH's net traded volumes and churn rate on a monthly basis in 2018.

Figure 8: CEGH's Net Traded Volume and Input Volume per Month, 2018



Source: CEGH

Figure 9: CEGH's Churn Rate per Month, 2018



Source: CEGH

2.3.4. Belgian Zeebrugge Beach (ZEE)

Belgium receives gas coming from Norway, the Netherlands, Algeria - through the Zeebrugge Beach LNG Terminal - and UK which is directed to France, Italy, Spain, UK, Luxemburg and Germany. Belgium is, therefore, an important transit country for gas, with the Zeebrugge area being one of the most important gas hubs in the EU28, with an overall throughput capacity of 48 bcm/year i.e. 10% of the border capacity needed to supply the EU28. The Zeebrugge hub is a physical transit hub and trades volumes at prices which are closely linked to those available at the NBP and the TTF. It includes both pipeline gas and LNG. Worldwide LNG supply is available through the Zeebrugge LNG terminal. The terminal has three primary shippers and standard provisions are in place to facilitate spot LNG deliveries. The Interconnector terminal in Zeebrugge connects the Belgian grid to the underwater Interconnector pipeline which runs to Bacton in the United Kingdom, while the Zeepipe terminal connects Norway's Troll and Sleipner gas fields to the Belgian grid via the underwater Zeepipe pipeline. LNG can be transported via small ships from Zeebrugge to all ports in Belgium and Northwest Europe.

Hence, it serves as a crossroads of two major axes in European natural gas flows: the east/west axis from Russia to the United Kingdom and the north/south axis from Norway to Southern Europe. In particular, the Zeebrugge area gives access to natural gas from Norwegian and British offshore production fields in the North Sea as well as from Germany and Russia.

Zeebrugge Beach (Physical Trading Services) is an entry point to the system and stays connected to the Interconnector Zeebrugge Terminal (IZT), the Zeepipe Terminal (ZPT) and LNG through ZeePlatform services. Zeebrugge Trading Point (Notional Trading Services) is automatically accessible through bookings in the entry/exit zone.

Map 6: The Zeebrugge Hub

Source: Fluxys

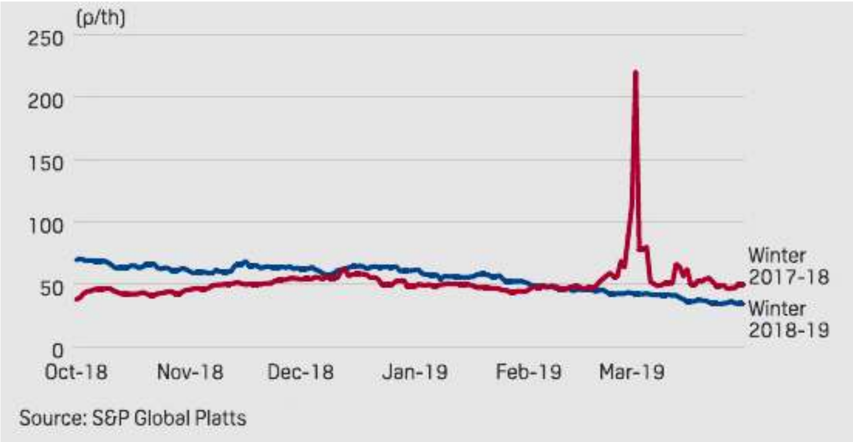
Belgium has significant storage facilities, with the most important being the Loenhout underground storage, with a working capacity of 0.7 bcm of high-calorific natural gas, a withdrawal capacity of 625 mcm/hour and an injection capacity of 325 mcm/hour. The Zeebrugge LNG Terminal on the other hand has a storage capacity of 0.38 bcm and a send out capacity of 9 bcm/year.

The LNG terminal is operated by Fluxys, Belgium's transmission system operator (TSO). Huberator—a subsidiary of Fluxys—is the operator of Zeebrugge Beach and Zeebrugge Trading Point (ZTP) and provides a package of services to customers trading volumes of gas. The natural gas entry/exit, which launched by Fluxys in October 2012, comprises one single trading hub where both virtual and physical services are available. Fluxys Belgium launched its central trading point ZTP in order to coincide with the launch of the entry/exit model. Hence, there are two forms of trading that are available at the ZEE: OTC, as facilitated by Huberator SA, and exchange-based, as facilitated by APX and Zeebrugge BV. As a bilateral gas trading point, Zeebrugge Beach in the Zeebrugge area is one of the most important European markets.

Currently, there is very little difference between the price of Belgian imported gas from Norway and the ZEE day-ahead price, which is itself also highly correlated with the LNG price. Belgium indeed pays low prices for imported LNG and, along with the UK, pays the lowest price for long-term contracts. This price convergence is most likely the result of the high-level integration of natural gas infrastructure in Belgium.

The trading activity on the Belgian Zeebrugge hub -- linked to the UK by the Interconnector pipeline -- pulled back due to the NBP fall, with 458 TWh seen in 2018, compared to 507 TWh in 2017 and 752 TWh in 2016.

Figure 10: ZEE Beach Spot Price Comparison



Source: S&P Global Platts

2.3.5. NetConnect Germany (NCG)

NetConnect Germany GmbH & Co. KG is Germany's largest gas grid market area operator and conducts the market area cooperation of the grid operators Bayernets GmbH, Fluxys TENP GmbH, GRTgaz Deutschland GmbH, Terranets bw GmbH, Open Grid Europe GmbH and Thyssengas GmbH for the consolidated market area NetConnect Germany (NCG). It covers the west and south of the country and connects the Netherlands, Belgium, France, the Czech Republic, Austria and Switzerland. Its main activities include the management of balancing groups, the operation of a virtual trading point, the handling of physical balancing activities and online provision of information, including billing and control energy data.

Germany is becoming an important transit hub for natural gas due to its broad cross-border pipeline infrastructure and its central location in Europe. Significant natural gas quantities are transited from Russia and Norway for delivery to other markets via Germany. Gas is imported via the pipelines from Norway, Russia, the Netherlands and to a small extent from Denmark and the UK. Germany has 48 gas storage facilities, making it the country with the largest storage capacity in Western Europe. The country has no LNG infrastructure so all of the country's natural gas imports are supplied via cross-border pipelines. However, some German companies have booked capacities in overseas LNG terminals.

Over the last years, Germany has improved its gas market by implementing an entry/exit system in compliance with EU regulations, reducing the number of market areas which used to be 19. In 2010, the market areas were reduced to 3 high calorific gas areas and 3 low calorific gas areas. In April 2011, the zones were reduced to 3 and in October 2011 there was a last merger which created 2 market areas, the NCG and Gaspool.

The new NCG, formed on the 1st of October 2011, improved competition and price formation and increased market liquidity. The traded volume at the two German trading points, NCG and Gaspool, has increased significantly making Germany's natural gas network more and more important for the European network.

Map 7: German Gas Market Area

Source: enet.eu

Liquidity on the NCG Virtual Trading Point (VTP) also shows an upward trend. Despite its short history, it has become an attractive trading hub, with around 330 trading participants for H gas (high calorific natural gas) and 180 trading participants for L gas (low calorific natural gas). In Germany, the NCG hub was largely unchanged year on year in 2018 at 1,499 TWh.

2.3.6. German Gaspool Balancing Services

Gaspool is the second gas hub of Germany and, like the NCG, it is run by six TSOs. It is a subsidiary of GASCADE Gastransport GmbH, Gastransport Nord GmbH, Gasunie Deutschland Transport Services GmbH, Nowega GmbH and ONTRAS Gastransport GmbH. The Gaspool market area, situated in Northern Germany, incorporates approximately 350 downstream gas transport networks. Gaspool is not an entry and/or exit network operator and operates more as a physical hub rather than a virtual one. As its title suggests, it offers balancing services and is used as a storage area.

Rather being based on the spot market, prices at the German hubs are established based on the German Border Price (GBP). The GBP, which is the average price for all German gas imports, is published each month by the German Federal Office of Economics and Export Control. The GBP is an average of the oil-indexed contracts that comprise the largest share of German gas supplies and spot supplies available at the Dutch-German border and Norwegian pipeline terminals. It is calculated by dividing the value of gas imports by the quantity of energy units. In 2018, Gaspool’s gas liquidity was slightly lower on an annual basis at 974 TWh.

Whilst this has improved the integration of South-West European natural gas markets, the European Commission has long established goals of creating a fully interconnected internal gas market (Regulation (EU) No 1227/2011[9]), increasing competitiveness and transparency throughout the European Union.

As such, Germany intends to merge its gas market areas, beginning at the start of the gas year, October 1, 2021, with completion by April 1, 2022. The upcoming merger is broadly seen as a positive development for liquidity, transparency and competition within the German wholesale gas markets. However, some market participants see potential issues with the merger, citing the infrastructural differences within the two trading regions. The Gaspool area is configured for low calorific L-gas, whilst the NetConnect area is configured for high calorific H-gas, which is mainly transited from the North Sea fields (Groningen) or Russia.

This merger was previously discussed by regulators in 2013, with the requirement to merge underpinned by legislative amendments to the German Gas Third-Party Access Regulations adopted in 2017, where the two market areas are to be consolidated into a single entry/exit zone by April 1, 2022 at the latest.

Since the 2013 discussions pertaining to a potential gas market merger, the two existing market areas (i.e. Gaspool and NetConnect) have developed dynamically. Today, they are two of the most liquid trading hubs – especially in the European spot market segment, which is reflected in the trading activities at the respective VTPs, characterised by growing trading volume and increasing churn rates.

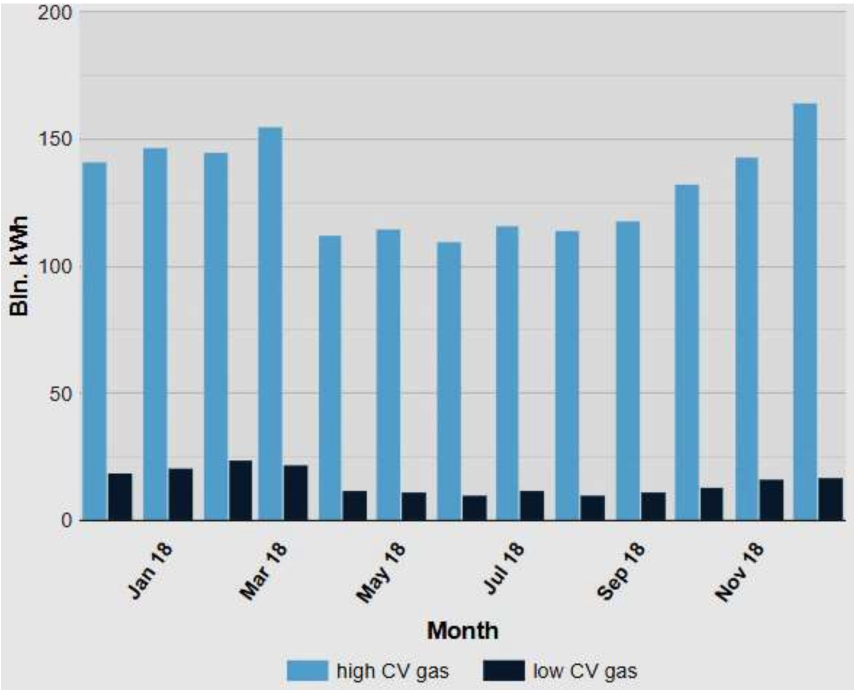
In the future, balancing group managers operating in Germany will only have a single counterparty for their balancing group contracts, regardless of which networks they use to transport gas within the national borders. Suppliers will have direct access to all end

[9] https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32011R1227

customers and previously separate networks will form a single entry/exit and balancing zone.

The impact that the German market merger may have on European gas pricing could be profound. Given the formation of a single entry/exit and balancing zone, the cost of transiting Russian gas to Belgium, France and the Netherlands could decrease, making Russian swing capacity more competitive within Western Europe. Ultimately, this phenomenon should provide the end-consumer with cheaper gas throughout Western Europe, whilst increasing competition amongst suppliers. This, along with the development of Nord Stream 2, which enables Russia to provide gas directly to Germany, circumventing Polish or Ukrainian gas transit fees, should provide lower pricing to the European consumer.

Figure 11: Gaspool's Trade Volumes per Month, 2018



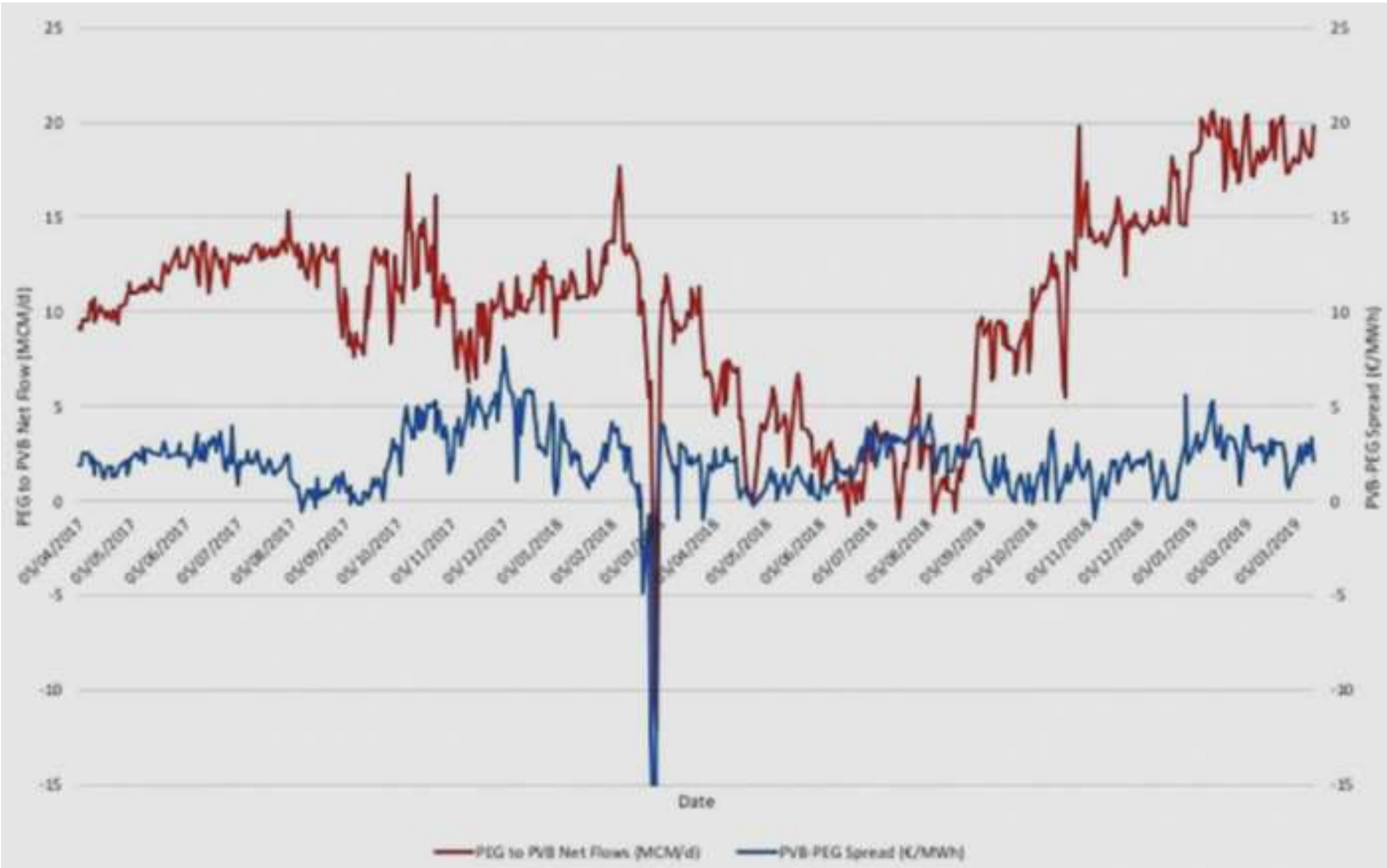
Source: Gaspool

2.3.7. French Point D' Echange De Gaz (PEG)

Located in France, the PEG hub is operated by GRTgaz. It is the result of the merger between PEG Nord and TRS. Tradable PEG contracts include futures instruments, trading up to the next 2 calendar years. More specifically, the two virtual trading points (VTPs), PEG-Nord and PEG-TRS, were merged on November 1, 2018, in order to form one single French VTP, titled Point d' Echange de Gaz (PEG), which serves Trading Region France (TRF). Many analysts anticipated an increase in liquidity and competition within the single national wholesale gas market, projecting an increase in cross-border arbitrage trade with Spain (PVB). Although a persistent cross-border premium of €1.25/MWh was available, many market participants were unable to access this arbitrage opportunity, which was characterised by the low net-flows between PEG (France) and PVB (Spain).

As shown in Figure 12, the PVB-PEG premium still exists post-merger; however, a palpable change in market dynamics can be observed. This can be further observed in Table 3, which shows that the coefficient of variation of the PVB-PEG spread, the standard deviation normalised for magnitude, has substantially reduced, indicating that a more stable France to Spain net flow has been established post-merger. This is further supported by the 88% post-merger increase in net flows between France and Spain, indicating that the South-West European wholesale gas markets are becoming more integrated.

Figure 12: PVB-PEG Differential



Source: S&P Global Platts

Table 3: Although the PVB-PEG Spread Appears to Have Increased Post-Merger, This is Misleading, As Arbitrage Flows to PVB Were Historically From PEG-TRS

Variable	Value
Pre-Merger PVB-PEG Spread	€2.1/MWh
Post-Merger PVB-PEG Spread	€2.26/MWh
Pre-Merger PEG-PVB Net Flows	8.99 mcm/d
Post-Merger PEG-PVB Net Flows	16.92 mcm/d
Pre-Merger Coefficient of Variation	1.23
Post-Merger Coefficient of Variation	0.49

Source: Woroniuk, D. (2019)[10]

[10] Woroniuk, D. (2019), "Gas Mergers Could Pressure Prices In Europe", https://oilprice.com/Energy/Natural-Gas/Gas-Mergers-Could-Pressure-Prices-In-Europe.html

In 2018, trading activity on the French hubs hit record annual highs of 606 TWh, up 27% on an annual basis.

Map 8: French PEG

Source: GRTgaz

2.3.8. Italian Punto Di Scambio Virtuale (PSV)

Italy has strong gas demand growth since it generates almost half of its power from gas. Europe's third-biggest gas market after Britain and Germany is emerging as Southern Europe's core gas trading point, as new pipelines and liquefied natural gas (LNG) projects make it one of the continent's most diversely supplied markets.

The Virtual Trading Point PSV, created in 2003, is operated by the Italian natural gas transmission system operator (TSO) Snam Rete Gas. The objective of the PSV Virtual Trading Point is to provide a matching point between supply and demand where bilateral transactions of natural gas take place on a daily basis, ensuring the accounting of the trading. The futures exchange is run by the energy market operator GME. GME organizes and manages the M-GAS natural-gas market, under which parties authorized to carry out transactions may make forward and spot purchases and sales of natural gas volumes. GME also organizes and manages the PB-GAS gas balancing platform, created at the end of 2011, under which authorized users enter mandatory daily demand bids and supply offers on their storage resources. There is also a third platform, P-Gas, which is a trading platform for monthly and yearly products. All platforms are managed by the PSV.

ENI, Italy's largest industrial company, and its subsidiaries (Snam Rete Gas, Stogit and Italgas) control about 70% of imports, 88% of production, 96% of transport and storage and about 50% of the final market (70% of wholesale and 30% of retail).

The smooth operation of the gas system depends upon efficient physical and commercial balancing, governed by the network code, which is almost identical to the British network code.

Physical balancing is the set of activities through which the TSO ensures the efficient handling of gas from injection to withdrawal points. Storage is the instrument used for the physical balancing of the network on a gas-day. Commercial balancing includes activities required for a proper accounting and allocation of transported gas, as well as for the fee system, encouraging market participants to keep any quantities injected and withdrawn from the network equal.

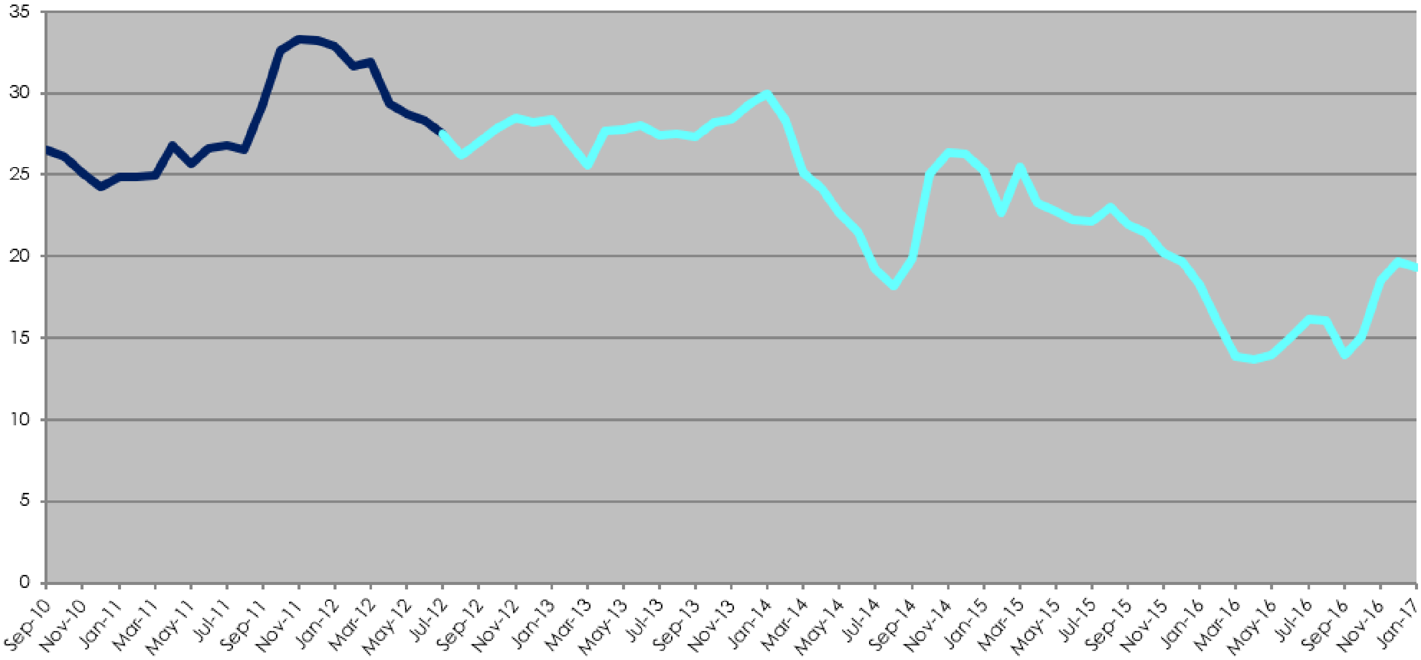
Insufficient liquidity and competition as well transportation constraints have kept Italian spot gas prices at a high level compared to other European hubs, with Italian day-ahead gas prices trading above 27 €/MWh, a premium of two euros to the Dutch TTF exchange.

Map 9: Italian Gas Transmission Network

Source: Snam Rete Gas

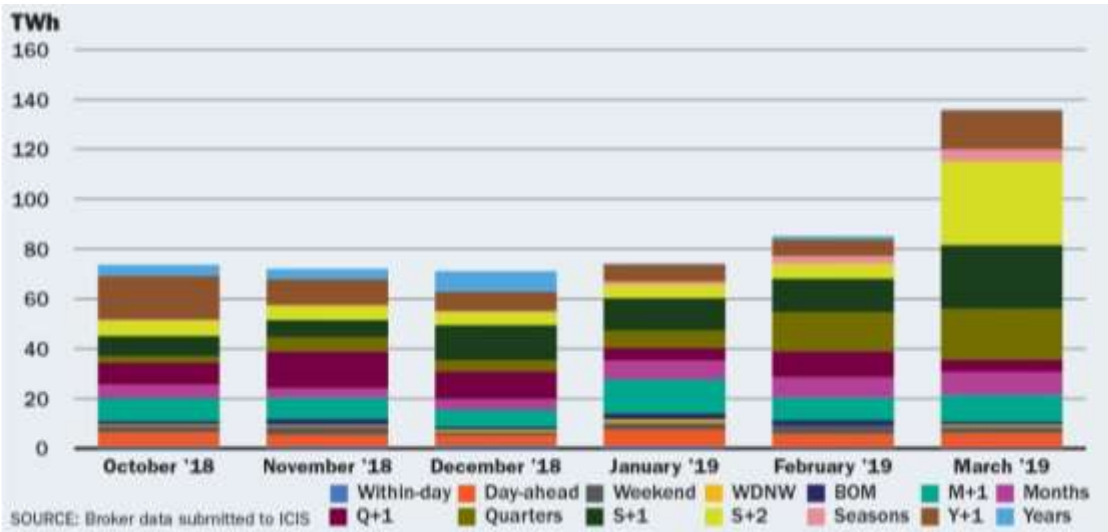
Figure 13 presents the Month Ahead Italian Gas Index (MAGI), which is an independent index of the Italian gas price at PSV, based 70% on confirmed transactions and 30% on a market-wide survey. MAGI fell to 13.73 €/MWh in April 2016, which was the lowest monthly price in the examined period (September 2010 – January 2017). Trading activity on the Italian PSV hub stood at 986 TWh in 2018.

Figure 13: MAGI Index from August 2012 and 70/30 Weighting of GeEO Transaction and Quotation Indices from September 2010 to January 2017 in €/MWh



Source: magindex.org

Figure 14: PSV March Liquidity Surge Driven by Front-Season Hedging



Sources: ICIS, broker data

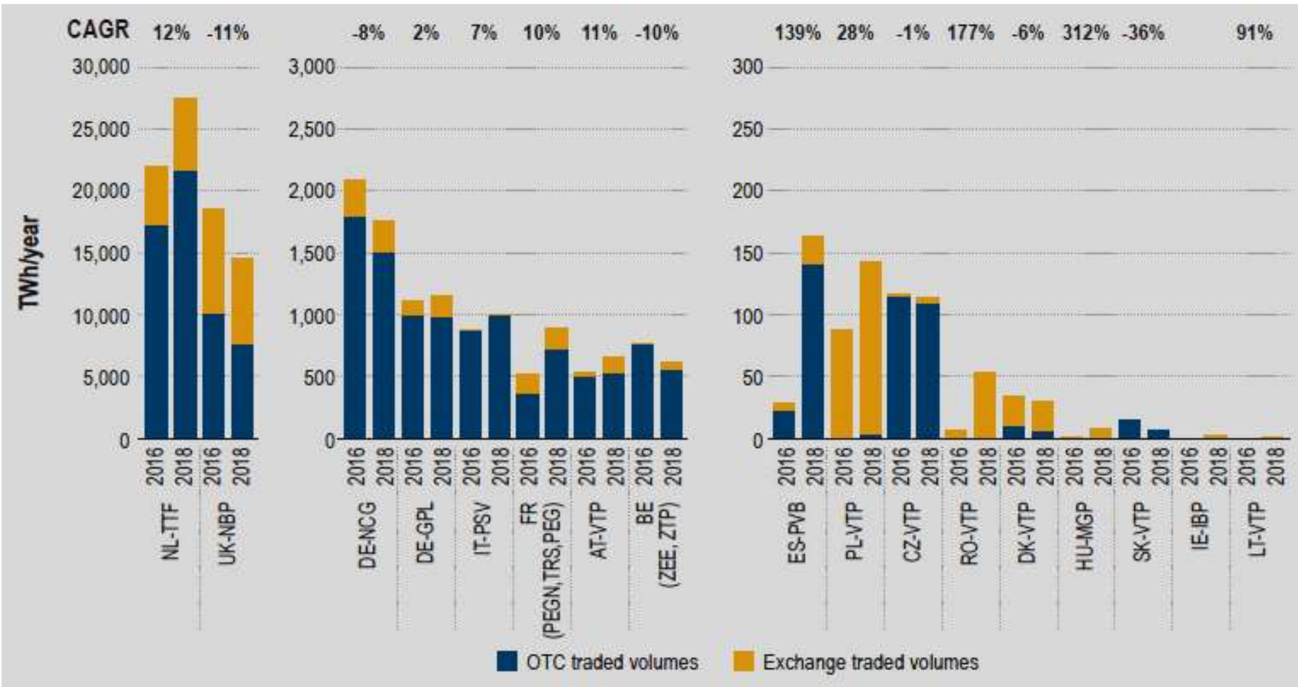
2.4. Trading Activity at European Gas Hubs

Total EU hub traded volumes were at a record high in 2018 – around 7% more gas changed hands at transparent trading platforms compared to 2017, and around 3% more than in 2016, which had been the previous record year. The growth of traded volumes at the largest gas hub in the EU, TTF, was particularly impressive, as volumes increased by more than 25%

compared with 2017 and accounted for over 90% of the total hub traded volumes increase in the EU. TTF, where market participants traded more than half of all the gas traded at EU hubs in 2018, has been growing by virtue of its growing role as the preeminent hub for transactions beyond the spot timeframe and attracting the bulk of forward trading activity in the EU.

There are substantial differences in volumes traded at different EU hubs as Figure 15 shows. The amount of gas traded at TTF or NBP is larger by a factor of at least ten with respect to any of the advanced hub's traded volumes and larger by a factor of one hundred when compared to any of the emerging or illiquid hub's traded volumes. The traded volume CAGR from 2016 to 2018 shows that the fastest growing hubs in this period were the Hungarian, Spanish and Lithuanian hubs. In absolute terms, however, both the Lithuanian and Hungarian hubs' additional traded volumes were relatively small. The Spanish PVB, on the other hand, was also amongst the hubs where traded volumes increased most in absolute terms. Other hubs with substantially increased absolute traded volumes in this period were PEGN, PSV, AVTP, ZTP and TTF, where, as mentioned previously, the majority of the growth of EU hub traded volumes took place.

Figure 15: Traded Volumes at EU Hubs (TWh/year and CAGR) – 2016 to 2018 (Three Scales)



Notes: Statistics refer only to volumes traded via transparent market platforms with a price reference and some kind of product standardisation; OTC refers to physically settled volumes traded among parties via brokers – with either the parties managing credit risk or trading being cleared by the broker; exchange execution denotes those volumes supervised and cleared by an organised central market operator. In some markets, sizeable volumes are traded, although not on transparent market platforms. These bilateral deals or swaps can also lack a price reference.

Sources: ICIS, broker data

The biggest decline in traded volumes took place at NBP, at the closely related Belgian ZEE and at the German NCG. In relative terms, a significant decline took place at the Slovak hub, which, together with the growth at the Hungarian MGP, resulted in the latter overtaking the former in terms of traded volumes. At some hubs, the changes in traded volumes coincided with businesses either entering or leaving the market; compared to 2016, the Hungarian, Spanish, Italian and Lithuanian hubs were among the hubs with most new active market participants, whereas NBP and NCG were hubs with the greatest decrease in the number of active market participants.

There were more than six hundred market participants active at EU gas hubs in 2018, an increase of more than 10% when compared with 2016. Unsurprisingly, the hub with the largest number of active market participants is TTF, with a third of all market participants active at EU hubs also active at the TTF. The criteria used for defining a market participant as active is that it concluded at least one trade during the year. It is clear that the use of a more continuous trading pattern as criteria would result in a shaper contrast between more liquid and less liquid hubs in number of active market participants.

Higher spot price volatility was one of the short-term factors that influenced hub trade of natural gas in 2018. The average volatility of hub spot prices was significantly higher than in 2017 at most of the assessed hubs as Figure 16 shows. Factors influencing volatility were the unforeseen cold weather spell at the end of winter 2018, the greater influence of global LNG market dynamics on EU hub's prices and the relative loss of supply flexibility at the key reference European markets TTF and NBP (Groningen and Rough facilities, respectively).

Figure 16: DA Volatility at Selected EU Hubs, 2016 – 2018 (Yearly Average)

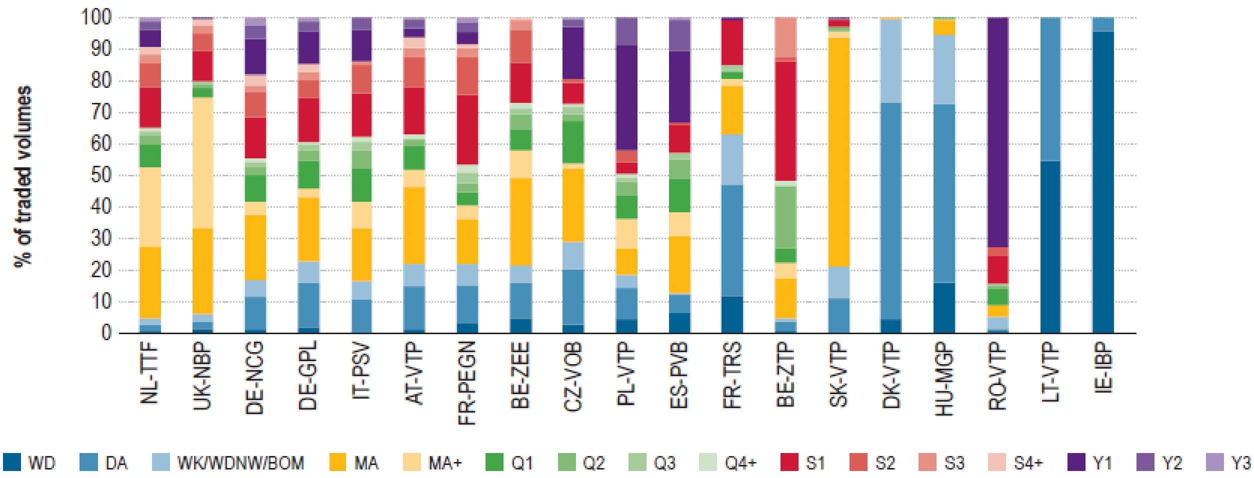
Notes: To conduct the volatility analysis, the logarithmic returns of daily gas hub settlement prices are first gauged. The standard deviation of returns is then calculated and multiplied by the square root of total trading days in a year. The value is expressed as a percentage.

Sources: ACER (2019), ICIS Heren, Platts

Breakdown of Gas Hub Traded Volumes

Figure 17 shows the relative importance of different types of products traded by market participants at EU hubs in 2018. It shows that spot products (DA, WD, BoM, etc.) make up a relatively small share of overall traded volumes at TTF, NBP and ZTP. At other EU gas hubs, spot market products represent between 10% and 100% of traded volumes.

Figure 17: Breakdown of Traded Volumes per Product at EU Hubs (2018) - % of Traded Volumes



__Notes:__ TTF and NBP data based on OTC trades only. Product acronyms stand for: Y years, S seasons, Q quarters, MA month ahead, WK/BOM week or balance of month. DA and WD refer to day-ahead and within-day respectively. The number following the acronym denotes the succeeding trading period (e.g. Q3 denotes the next third quarter after trade conclusion. Quarters comprise strips of three individual and consecutive contract months, from either Jan-Mar, Apr-Jun, Jul-Sep or Oct-Dec.).

Sources: ACER (2019), REMIT data

Medium-duration contracts (such as month, quarter and season contract types) represent the largest share of traded volumes at EU hubs, with the exception of some hubs where only spot products are traded. Long-duration products (or yearly contracts) have a large share of traded volumes at the Romanian, Spanish and Polish hubs, a result of local market specificities and legal obligations, but make up a relatively small share of traded volumes elsewhere. Furthermore, yearly products are not particularly liquid at the Romanian, Spanish and Polish hubs, but are rather transacted on few occasions in big volumes.

__Liquidity at EU Hubs' Spot Markets__

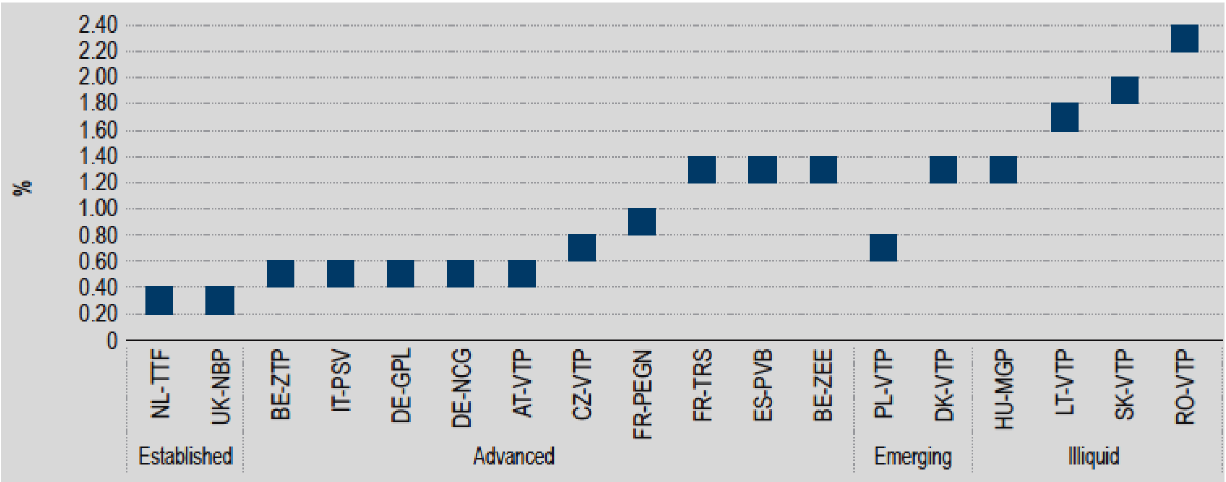
EU hubs spot markets have the highest trading frequency of any traded timeframe. At some EU gas hubs, market participants only trade spot gas products and for most hubs, spot product trades represent the majority of hub trades, if usually not the majority of traded volumes.

In 2018, the average number of trades on the spot market increased at the majority of hubs when compared with 2017. The exception to this trend were NBP, ZEE, and the Czech, Polish and Slovak hubs. Market participants were most active on the TTF hub, where more than 1000 DA trades were concluded in an average trading session in 2018. In a positive development compared with last year's assessment, in addition to TTF, both German hubs met the AGTM threshold of an average of 420 DA trades per trading session in 2018. Furthermore, NBP, the Austrian, French PEGN and Italian hub's spot trading frequency was also substantial, with more than 200 trades concluded per day on average. In the group of advanced hubs, the Belgian ZTP stood out in terms of relative growth of the number of DA trades, indicating that quite some spot trading activity has migrated there from the physical ZEE hub, which is losing volumes. The growth of spot trading activity at the Spanish PVB was also impressive, with the number of trades more than doubling compared with 2017.

In the group of emerging hubs (PL and DK) spot trading frequency is quite homogeneous, with market participants concluding around 30-50 trades per day at each of the hubs. In the group of illiquid hubs, which includes a number of hubs for which AGTM metrics cannot be assessed due to either the absence of a virtual hub or the absence of liquidity at the hub, there were some positive signs of market activity. There was, for instance, a greater number of spot trades in the Baltics and Romania; and the introduction of a virtual hub in Ireland at the end of 2017 resulted in the development of some spot liquidity during 2018.

The bid-ask spread, presented in Figure 18 for the different EU hubs, is the difference between the prices available in the order book for an immediate sale (offer) and an immediate purchase (bid) of a physically settled gas product. The size of the bid-offer spread is one measure of the size of the transaction cost and of liquidity of hubs. The lower the bid-ask spread, the lower the transaction costs and the higher the liquidity.

Figure 18: Bid-ask Spread of EU Hubs Spot Markets (Percentage of DA Ask Price Shown as a Range) – 2018



Note: Bid-ask spread is a measure of the average difference between the lowest ask-price and the highest bid-price expressed as a percentage of the highest bid-price across the day. Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed.

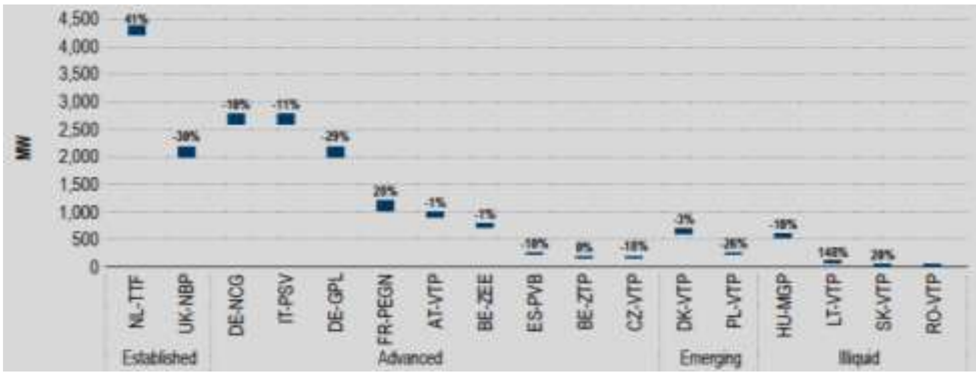
Sources: ACER (2019), REMIT data

At most hubs, the DA products' bid-ask spread was narrower than in the previous two years. This improvement means that besides TTF and NBP, also ZTP, PSV, GPL, NCG and AVTP were all in line or close to being in line with the AGTM recommended threshold of 0.4% of the bid price (as the bid-ask spread is measured relative to the commodity price, the improvement can be partially attributed to higher gas prices in 2018).

Compared with 2017, the bid-ask spread narrowed the most at the Belgian ZTP, Czech VOB and Hungarian MGP, though in the case of the latter, it was still relatively high at more than one per cent of the bid price. The exceptions to the positive developments were the Lithuanian hub, ZEE, PEGN and the Slovak hub, where the average DA bid-ask spread widened.

Compared to 2017, the already substantial TTF order book continued to grow as Figure 19 shows. The order book volumes metric refers to the availability of orders at any time. Besides TTF, both German hubs and the Italian PSV are all in line with the AGTM recommended threshold of 2000 MW of gas available in the order book. The sizeable demand at these hubs, the associated balancing needs of market participants and the Balancing Network Code stipulation that market participants have primary responsibility for balancing their positions could explain this evolution.

Figure 19: Available Spot Order Book Volumes – MW (Lower of Bid- and Ask-Sides During the Day for DA Products, OTC and Exchange Aggregated Shown as a Range; y-o-y Change) – 2018

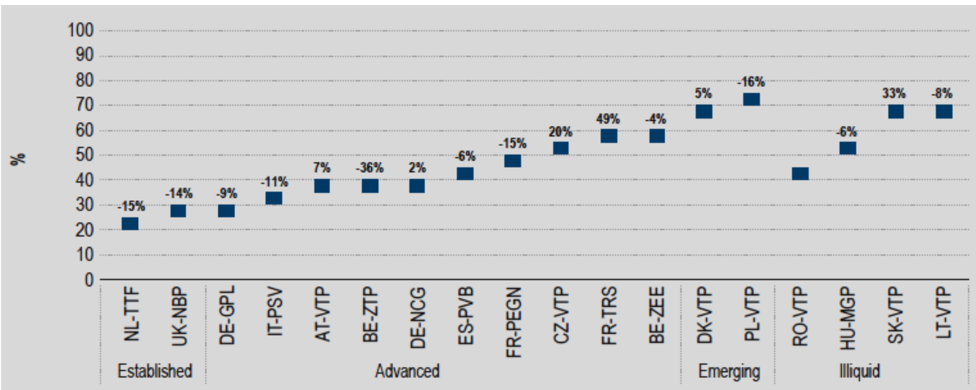


Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed. Hubs with no y-o-y percentage were not previously assessed (ROVTP) or cannot be compared like for like with last year's assessment (NBP).

Sources: ACER (2019), REMIT data

The spot order book size at AVTP, PEGN, ZEE and also at the Hungarian and Danish hubs was also substantial, although below the AGTM benchmark. Market makers play an important role in many hubs in building order books during the development towards a more mature hub. Figure 20 shows that in 2018, spot market competition was relatively healthy at most EU gas hubs; however, the Polish, Danish, Slovak and Lithuanian hubs were assessed to have relatively high concentration levels.

Figure 20: Spot Market Concentration – CR3 (Average CR3 Shown as a Range for Concluded DA Trades, y-o-y Change) – 2018



Note: CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was highest. Intragroup trades included. Hubs with no y-o-y percentage were not previously assessed.

Sources: ACER (2019), REMIT data

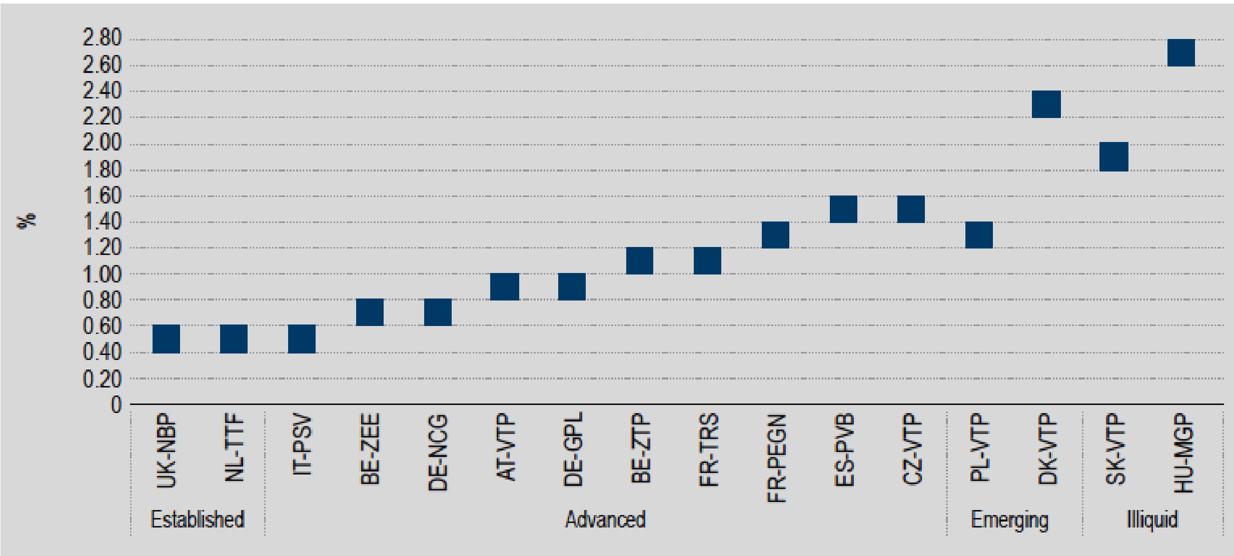
Liquidity at EU Hubs' Prompt Markets

Trading activity on the prompt (or near curve) markets, as measured by the daily average number of MA trades, is much less evenly distributed among EU hubs than that on the DA market. Most of the prompt trading activity is concentrated at TTF and NBP, as these two hubs attract both market participants with physical exposures at other EU hubs looking for hedging opportunities and traders looking to speculate on gas price movements in the EU. The division between NBP and TTF and other EU hubs had become even starker in 2018, as market participants concluded fewer MA transactions outside of NBP and TTF than in the previous years.

In 2018, more than 1200 MA trades were concluded on an average trading session at TTF or NBP, which is comparable to the result for 2017. The front month is one of the crucial traded timeframes for the two established hubs, as unlike at other EU gas hubs, market participants conclude more prompt than spot trades on an average trading day. At other hubs, there was on average 60 or less MA trades per trading session: NCG, GPL, AVTP, PSV, the Polish hub, PVB and PEGN were the hubs with most prompt trading activity outside of the established hubs.

Figure 21 shows that the tightest MA bid-ask spreads were assessed at TTF, NBP and PSV. Other hubs' average MA bid-ask spreads were considerably higher, with those at NCG and the Polish hub widening the most compared with 2017. Hubs with a positive trend of narrowing bid ask spreads include ZTP, PVB and the Slovak, Danish and Hungarian hubs.

Figure 21: Front Month Bid Ask Spread (Best of Either Exchange or OTC, Percentage of MA Ask Price Shown as Range) – 2018

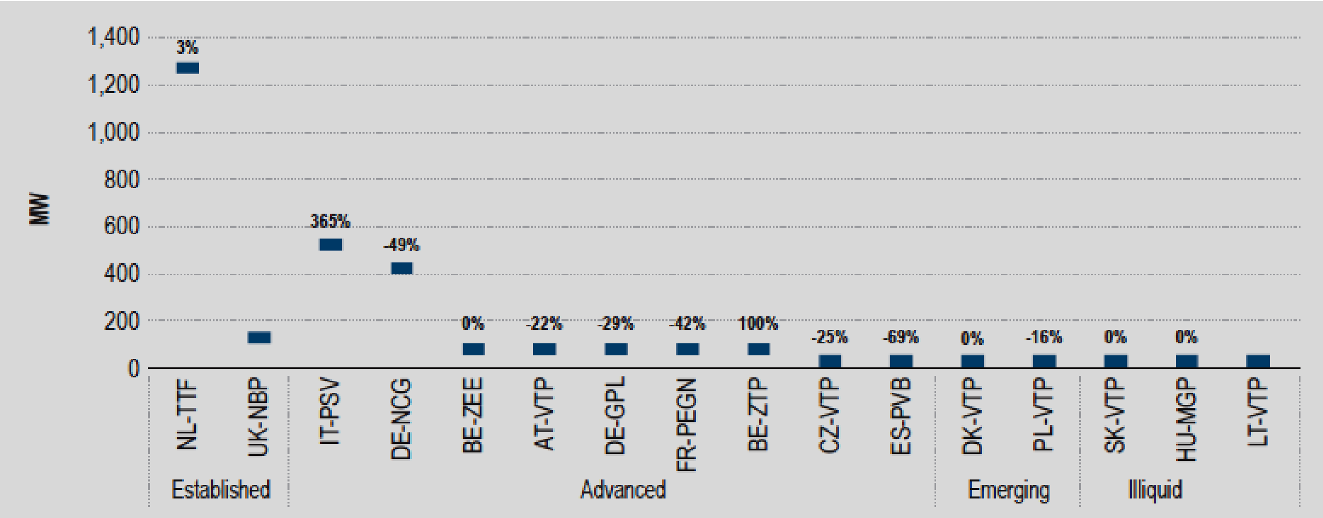


Note: Bid-ask spread is a measure of the average difference between the lowest ask-price and the highest bid-price expressed as a percentage of the highest bid-price across the day. The order book of NBP refers to OTC only; exchange order books could not be reliably assessed.

Sources: ACER (2019), REMIT data

The prompt order book is in line with the AGTM threshold at TTF and, after expanding considerably in 2018, at the Italian PSV. The German NCG is also close to the AGTM recommended threshold of 470 MW. Other EU hubs' MA order books were considerably shallower as can be seen in Figure 22.

Figure 22: Available Prompt Order Book Volumes – MW (Average Bid and Ask-sides During the Day for Month-ahead Products Shown as a Range, OTC and Exchange Aggregated, y-o-y Change) – 2018

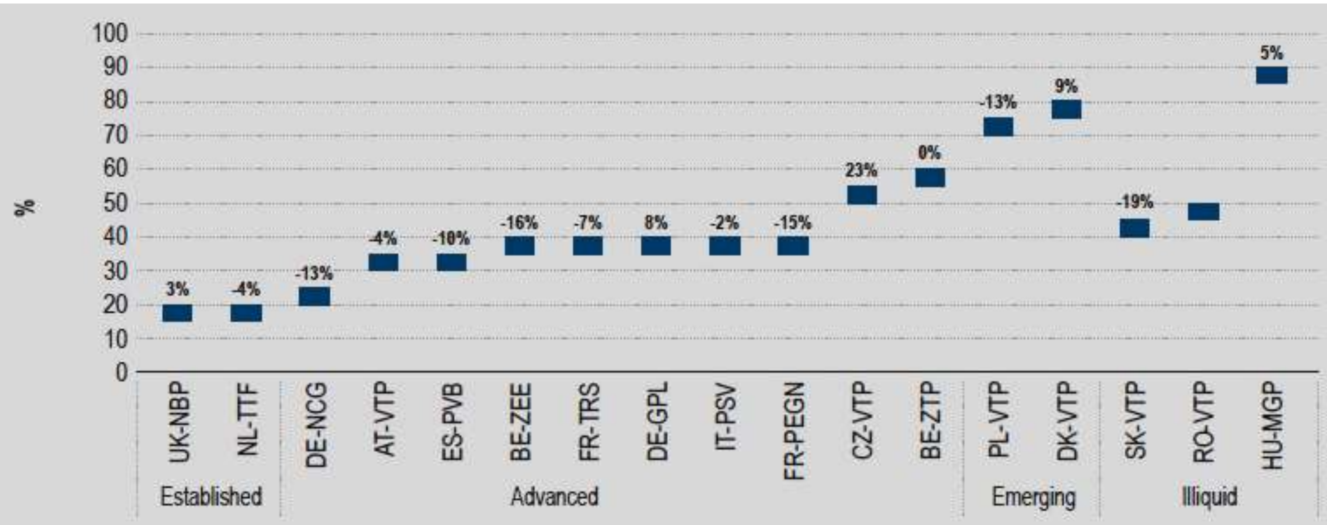


Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed. Hubs with no y-o-y percentage were not previously assessed (ROVTP) or cannot be compared like for like with last year's assessment (NBP).

Sources: ACER (2019), REMIT data

Figure 23 shows that the most competitive prompt markets in 2018 were those associated with the NBP and TTF hubs, where the average trading session's CR3 (which measures the market share of the three largest market participants on the buying and selling side of a trading session) was below 20% in 2018.

Figure 23: Prompt Market Concentration – CR3 (Average CR3 for Concluded MA Trades Shown as a Range, y-o-y Change) – 2018



Note: CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was highest. Intragroup trades included. Hubs with no y-o-y percentage were not previously assessed.

Sources: ACER (2018), REMIT data

Of all the assessed hubs, the most concentrated prompt markets were those at the Polish, Danish and Hungarian hubs, where, with the assessed CR3 above 70% on average, there is evidence that only a handful of market participants dominated trade on the prompt market.

Liquidity at EU Hubs' Forward Markets

The forward markets with the highest liquidity in the EU are those at TTF and NBP. In fact, the analysis of the hubs' trading horizon reveals that frequent trading beyond the season-ahead takes place almost exclusively at TTF and NBP. However, this does not mean that forward products are not traded at other hubs – data shows that, on average, at least a couple of forward products change hands at most advanced and emerging hubs in every trading session.

The greatest expansion of trading horizon in 2018 took place at TTF, where market participants now frequently trade gas for delivery beyond three years in the future. The trading horizons of NBP (28+ months into the future) and NCG (8+ months into the future) also expanded substantially, though this was preceded by a contraction of forward trading horizon in 2017. At other hubs, the trading horizon was either comparable or slightly greater than in 2017, notably, at least in relative terms, at the Polish and Spanish hubs. However, it should be noted that bar NBP and TTF, no hubs' trading horizon comes close to the AGTM recommended threshold of eight daily trades for products delivering at least 22 months into the future from the time of the trade.

When the criteria of the trading horizon are lowered to two daily trades, a somewhat different picture of forward trading at EU hubs emerges. TTF and NBP are not affected much by the change in criterion but what is revealed is that at most advanced and emerging hubs forward products are traded, though at a much lower frequency than at established hubs.

In 2018, of the assessed hubs' order books only TTF had a sizeable forward order book horizon. As Figure 24 shows, a number of other hubs have volumes available in their order books on the far curve; however, the available volumes are much smaller than those at TTF.

Figure 24: Order Book Horizon - Months (Lower of Either the Bid or the Offer Side, 2018)

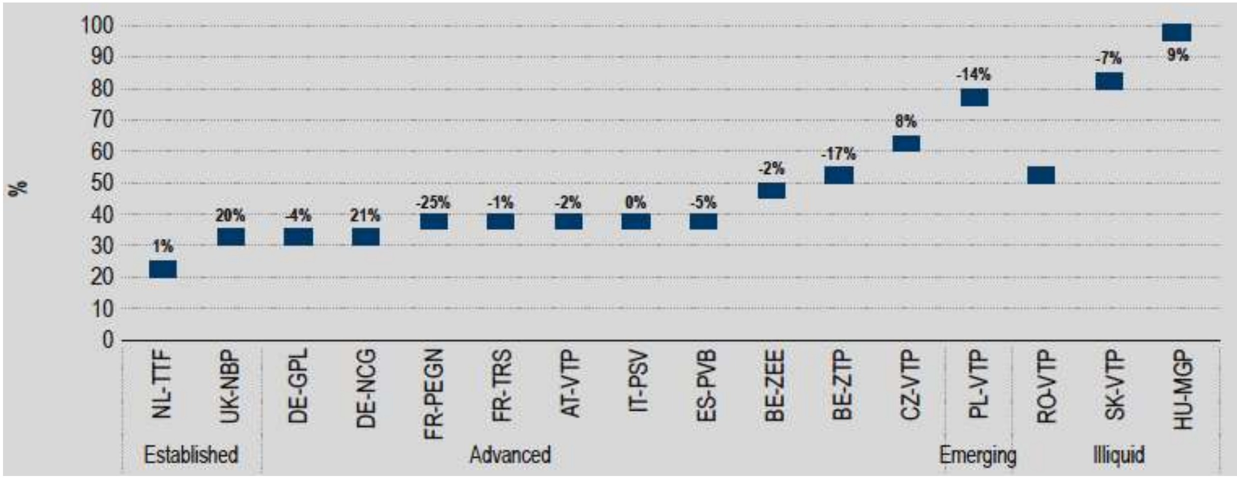
Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed.

Sources: ACER (2019), REMIT data

Unlike the assessment of competition at hubs' spot and prompt markets, where the analyses are based only on the DA and MA products, the assessment of competition of the forward markets takes into account a basket of forward products.

Figure 25 shows that in 2018, the most competitive EU gas forward markets continued to be those associated with the TTF and NBP hubs, even as in the case of the latter concentration increased over recent years. Most *advanced* hubs' forward market competition was relatively strong, as only the two Belgian hubs' and the Czech hub's CR3 were assessed above 40%. Concentration at emerging and *illiquid* hubs' forward markets is considerably higher.

Figure 25: Forward Market Concentration – CR3 (Average CR3 of Trades Concluded for a Basket of FW Products Shown as a Range, Relative y-o-y Change) – 2018



__Note:__ CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was highest. Intragroup trades included. Hubs with no y-o-y percentage were not previously assessed.

Sources: ACER (2019), REMIT data

According to the Quarterly Report on European Gas Markets published by the European Commission **(11)**, liquidity on the main European gas hubs increased in the fourth quarter of 2018, with total traded volumes amounted to around 12,414 TWh (equivalent to around 1,144 bcm), 12% more than in the same period of 2017. This was around 11 times more than the gas consumption in the seven Member States[11], covered by the analysis in Q4 2018. In October and November 2018, traded volume of gas on the European hubs showed a strong increase in year-on-year comparison (in November 2018, with a volume of 4,615 TWh, reaching the highest since the beginning of available data series from the European Commission); however, in December it fell back again.

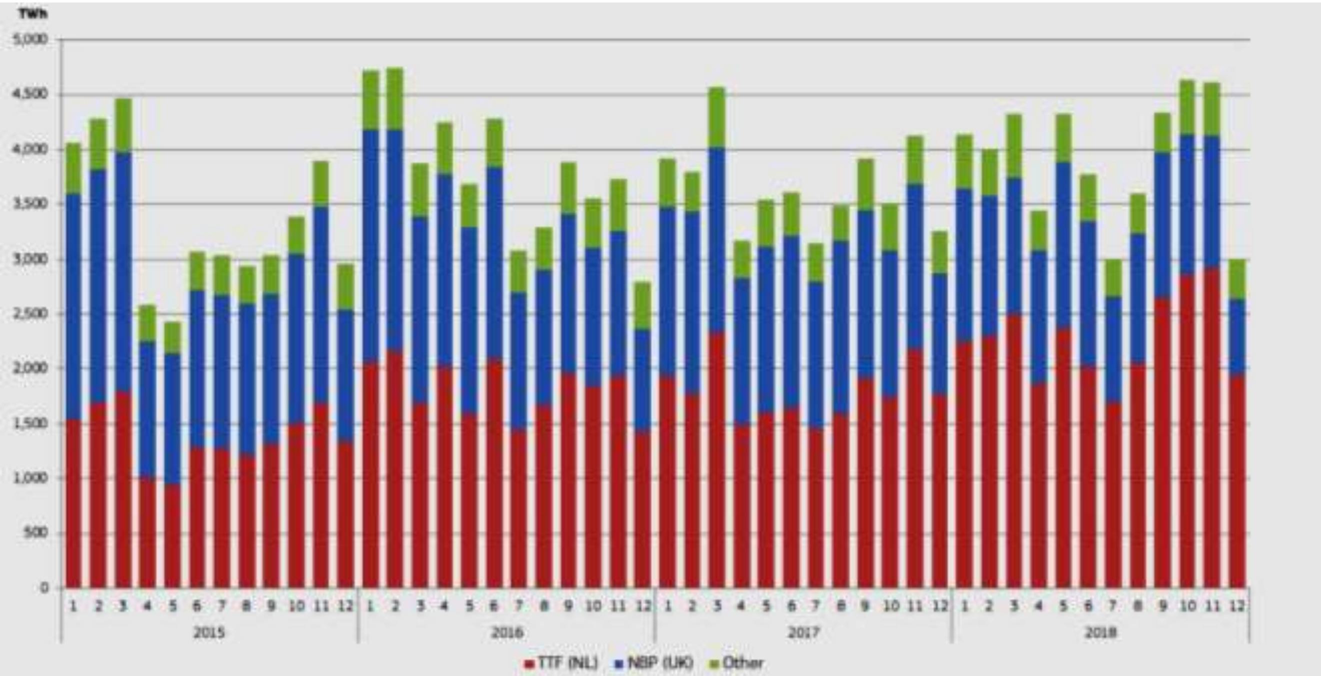
Traded volumes in the fourth quarter of 2018 increased year-on-year in the French (53%), Dutch (36%), Austrian (22%) and Italian hubs (19%), while in the UK (-19%) and Belgium (-18%) traded volumes decreased, compared to Q3 2017. On the German hub, the traded volumes did not show any change in year-on-year comparison.

[11] Netherlands, UK, Germany, France, Italy, Belgium and Austria.

As from November 1, 2018, the two French markets (PEG Nord and TRS) were merged, creating a new single market, the volume picked up and showed the highest increase compared to Q4 2017 among all regional gas hubs in Europe. The Belgian hub suffered from decreasing activity on the Belgian-UK interconnector, as shipments were redirected towards the Dutch-UK link, offering more favourable transit costs.

On the UK NBP hub, 48% of total traded volumes were executed directly on an exchange in the fourth quarter of 2018. This share was 26% on the Dutch TTF hub, 19% at the French hub, 15% at the German hub, 20% at the Austrian hub and respectively only 3% and 1% and the Belgian and Italian hubs. In France, the share of exchange trade was markedly lower than a year earlier (-15%), similarly to Italy (-8%), while it increased in Austria (+12%).

Figure 26: Traded Volumes on European Gas Hubs (2015-2018)



"Other" includes the following trading hubs: Germany: NCG (NetConnect Germany) and Gaspool; France: PEG (Point d'Echange Gaz); Italy: PSV (Punto di Scambio Virtuale); Belgium: Zeebrugge beach. 1 bcm is equivalent to 10.647 TWh.

Source: European Commission, Quarterly Report on European Gas Markets (Vol. 11)[12]

In order to evaluate the depth, liquidity and transparency of the traded gas hubs across Europe, the Oxford Institute of Energy Studies has proposed a methodology using the following 5 Key Elements[13]:

- Who trades in each of the hubs?
- What products are traded there?
- How much volume is traded, and over which periods?
- The Tradability Index
- The churn rates

[12] European Commission (2019), "Quarterly Report on European Gas Markets", *Volume 11 (Issue 4, Q418),* https://ec.europa.eu/energy/sites/ener/files/quarterly_report_on_european_gas_markets_q4_2018.pdf

[13] Heather, P. (2019), "A Hub for Europe: The Iberian promise?", *OIES Paper: NG 143*, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/03/A-Hub-for-Europe-the-Iberian-promise-NG143.pdf

They are all important, but the churn rate is possibly the pre-eminent factor. From the results, it is possible to determine which hubs are 'mature', which are active, which are improving and which are yet to show signs of development.

Table 4: Summary of the 5 Key Elements (2018)

2018	5 KEY ELEMENTS					
HUB	Active Market Participants*	Traded Products**	Traded Volumes	Tradability Index (Q4)	Churn Rate	Score /15***
TTF	189	50	28220	20	70.9	15
NBP	151	44	15105	16	16.9	14
NCG	137	23	1760	15	3.8	9
GPL	105	21	1150	14	2.8	9
PSV	102	20	1060	14	1.4	9
VTP	83	16	650	10	6.9	8
TRF	50	17	780	12	1.7	7
ZEE	47	16	460	7	3.1	7
ZTP	45	12	150	3		7
PVB	41	11	100	0	0.3	5
VOB	19	11	80	5	0.9	5

* Hub Score in the OTC Active Traders table.
** Score /56 derived from the OTC and Exchange product categories in the Traded Products Table.
*** Score based on each of the Key Elements scoring zero for Grey; 1 point for Red; 2 points for Amber; 3 points for Green.

Source: Heather, P. (2019)

Table 4 is a summary of each of the five elements. The Oxford Institute of Energy Studies has then used a simple scoring methodology to derive the final ordering of the hubs, to reflect their level of development: mature, active, poor and inactive as indicated in Map 2. The points system is indicated at the bottom of the table and, adding up each of the constituent Key Elements will give a hub score out of 15. A hub is classified as being 'mature' if the score is 12-15; 'active' if the score is 8-11; 'poor' if the score is 5-7; and 'inactive' if the score is 1-4.

The results show that in 2018, taking all five key elements into account, the TTF and the NBP are the only gas trading hubs that can be considered as mature, deep, transparent and liquid. NCG, GPL, PSV and VTP are active hubs with developing depth, transparency and liquidity; all the other hubs cannot be considered as deep, transparent or liquid.

In order to evaluate the path to liberalisation and market development, the political willingness and cultural attitudes to trading that are also key to the development of successful gas trading hubs are assessed; in turn, these often dictate the level of commercial acceptance in a given country.

The EFET[14] Review of Gas Hubs Assessments quantifies 5 regulatory conditions, 6 TSO conditions and 6 market conditions; these broadly follow the "Three Main Indicators". Their 2018 Review **(12)** was used to create Table 5, which summarises the scores awarded by EFET to each of the gas trading hubs in Europe, including the emergent hubs, covering 17 criteria

[14] The European Federation of Energy Traders (EFET)

regarding the development of a hub for which they give a score of 0-2 out of a possible total of 20.

The order of the hubs in the top half of the table is almost identical to that in Table 4, except that EFET did not distinguish between the three PEGs (prior to zone mergers), that the NBP and TTF rankings are reversed and that the French/Belgian and Italian/Austrian hubs are reversed: these reversals of order show that a good framework to trade does not always lead to high volumes and vice-versa. Indeed, EFET has now dropped its review of the ZEE hub following that hub's diminishing importance in European gas trading. The active category is rounded off with the VTP and PVB.

EFET gives the Danish GTF hub a relatively good mid-market score, placing it at the top of the poor category (even though there is relatively little trading), just ahead of the Czech VOB, followed by the Hungarian MGP. Interestingly, the Polish VPGS just makes it as a poor hub with a score of 9½ (although there is reasonable trading, along with the Slovak SK).

Finally, the remaining 6 hubs studied have low to very low scores, classifying them as inactive; indeed, the two SE European hubs in Romania and Bulgaria are still at the planning stage, as is the Portuguese hub. The Greek hub officially started balancing operations in July 2018. EFET also analyses the Turkish UDN and the planned Ukrainian hub but, so far, has not studied the IBP (planned Irish hub).

Table 5: EFET Hub Scores Categorised as Mature, Active, Poor and Inactive, 2014-2018

HUB	2014	2015	2016	2017	2018
NBP	20	20	20	20	20
TTF	19	19½	19½	19	19
NCG	15½	19	19	17½	17½
GPL	16	19	19	17	17
ZTP	16	17½	18	19	17
PEGs	16	16½	18½	17½	17
ZEE	17	17	17	16½	n/a
PSV	10½	15	15	16	16½
VTP	13	13	13½	16	16½
AOC/PVB	7	7	13½	16	15½
GTF	9	11	14	15½	14½
VOB	8	8½	9½	13	14
MGP	5	6½	9	12½	11½
VPGS	4½	5½	9½	10	9½
SK	3½	7	8	8½	9½
GR	4½	5½	5½	6½	8½
UDN	5½	5	4	5½	6
BG	1½	1	1½	1	4½
PT	n/a	n/a	n/a	n/a	4½
UA	n/a	n/a	n/a	3½	3½
RO	2½	1½	2	3	3

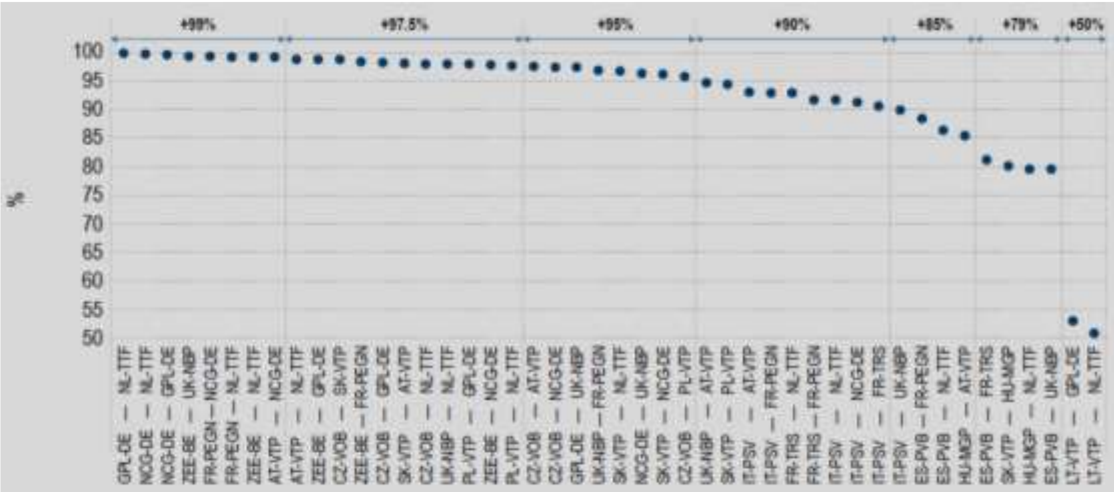
Sources: Heather, P. (2019), EFET (2018)

2.5. Gas Prices on European Hubs

In addition to liquidity and trade competition at virtual hubs, a crucial component of the AGTM is the idea of market integration, defined as gas moving between market areas to virtual hubs where it is most highly valued by gas market participants. This implies that the prices of gas at different virtual hubs would not only be correlated, but would converge over time, to the extent allowed by the efficient use of transportation capacity. In order for this process to take place, liquidity at gas hubs is key, as it means that reliable price signals emerge, allowing market participants to direct gas flows from low- to high- price hubs.

High correlation between EU gas hub's spot prices, in particular between TTF's and other EU hubs' spot prices, is one of the reasons behind the emergence of TTF as the venue for forward price and supply hedging for market participants with physical positions throughout the EU. High price correlation means that market participants can use TTF as a venue to hedge their exposures at other hubs by approximation (proxy hedging). Positions opened on TTF can then be unwound before delivery and replaced with either buy or sell positions in hubs where those market participants actually have their physical position. The high price correlation between hubs means that risks associated with proxy hedging strategies are relatively low.

Figure 27: Correlation of Selected Hub Spot Prices – 2018



Notes: Correlation measured as Pearson coefficient. The Pearson correlation coefficient is a measure of the linear correlation between two variables X and Y. In this example of X and Y are closing prices of gas for delivery on the next day at two EU gas hubs. 100% is total positive linear correlation, 0% is no linear correlation, and −100% is total negative linear correlation.

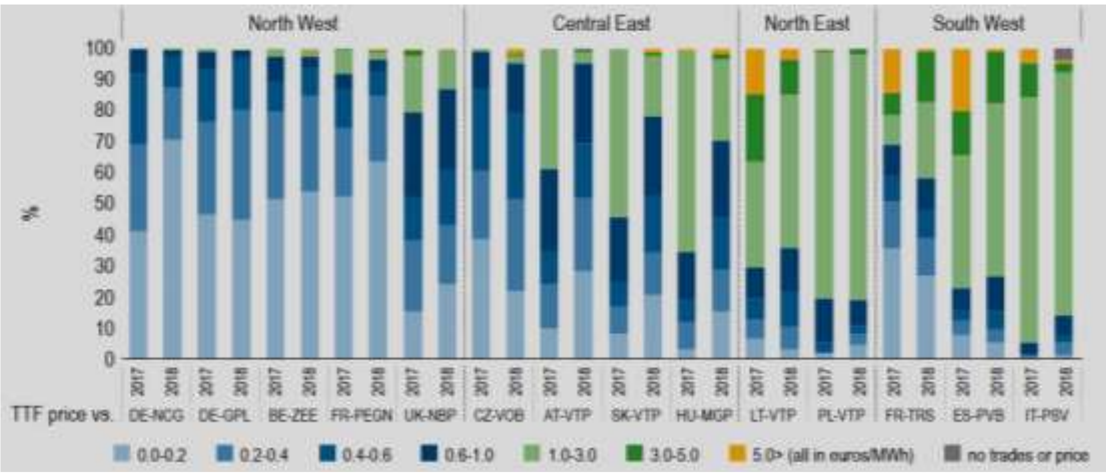
Sources: ACER (2019), ICIS Heren, Platts

High correlation is evident in particular between continental NWE hubs. The main reasons for high correlation between NWE hubs are availability of connecting pipeline capacity, similar market fundamentals, the possibility for upstream suppliers to adjust flows into these markets based on price signals, the structural fostering of hub trading and the relatively lower-priced cost of transportation capacity between the concerned markets. Surpluses of long-term capacity contracts (LTCs) are also a relevant factor as they lower the marginal cost of locational physical arbitrage; however, correlation remained strong in 2018, even as some LTCs expired.

Among the assessed neighbouring and connected hub pairs, it was the spot prices at the Hungarian and Spanish hubs which were the least correlated to their respective neighbouring hub's prices, although correlation was still relatively high at above 85%. In the case of PVB, the relatively low correlation could be due to the relatively small amounts of cross border capacity available for hub arbitrage and the relatively high price of cross border transportation capacity. In the case of Hungary, it could be due to the inability to export gas to the neighbouring Austrian and Slovak hubs, whose spot prices were more frequently at a premium to the Hungarian MGP than in previous years. However, due to pipeline transportation system limitations, the resulting spread could not be arbitraged away.

Overall, price convergence in most parts of the EU remained high in 2018 compared to previous years, as Figure 28 shows. It continued to be the highest between NWE hubs where spot price spreads between TTF and NWE hubs (including AVTP and VOB) were below 1 €/MWh for 90% of trading days in 2018.

Figure 28: DA Price Convergence Between TTF and Selected EU Hubs (Trading Days Within Given Price Spread Range, %) – 2017 to 2018



Note: Spreads in €/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

Sources: ACER (2019), ICIS Heren, Platts

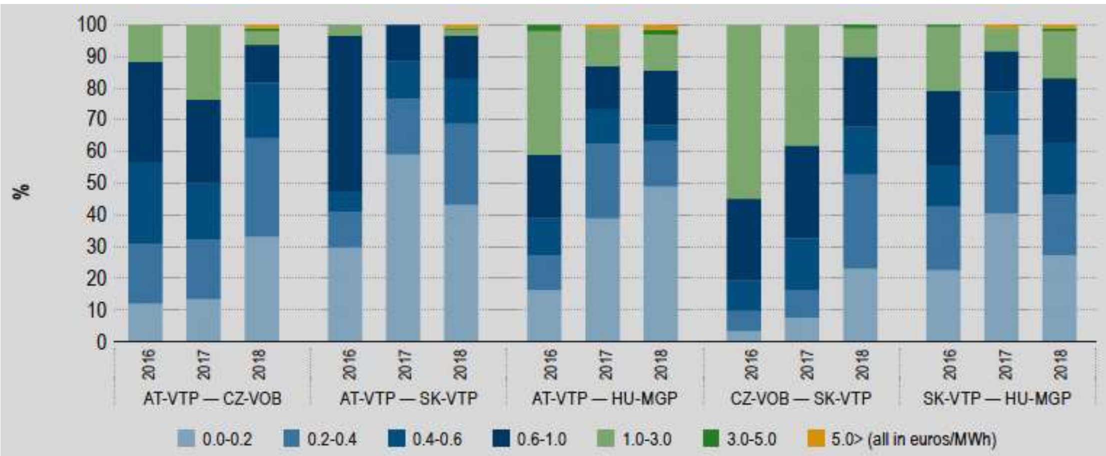
In 2018, spot price convergence between the Dutch TTF and other EU hubs improved or remained similar to 2017. Of the assessed hubs, the Mediterranean hubs (PSV, PVB and TRS) and North East European hubs (PLVTP and GET Baltic) continued to have the most frequent high spreads with TTF.

Price convergence among markets within a given region is usually higher than between markets in different regions. This is because suppliers active in markets inside a region have portfolios which tend to be similar, which allows for more similar hub quotations. Moreover, regional market fundamentals tend to be similar – e.g. weather-driven demand and impacts of infrastructure outages. The market role that hubs play is usually more akin at regional level, and price arbitrage trading actions are more apparent. For example, in many instances, the same market players keep positions between adjacent hubs (e.g. buying in one and delivering in the other, swapping volumes). All these factors contribute to constructing a closer relationship between prices. To better understand these dynamics, the remainder of this Chapter looks at the convergence of spot market prices between the German hubs and its neighbouring markets; hub price convergence in Central Eastern Europe; and hub price convergence in South West Europe.

By virtue of its location, the German gas transmission system plays these days a crucial role in linking NWE European gas hubs with hubs in the South and in particular Central East Europe. In 2018, prices between NCG and neighbouring hubs further converged compared to 2017, the exception being the Czech hub. In the case of GPL, convergence with neighbouring hubs was similar to that in 2017. Spreads between German and neighbouring hubs were lower than 1 €/MWh for at least 90% of days in 2018, apart from spreads with the Italian PSV (which is only indirectly connected with the German hubs via Switzerland) and the Polish hub. In the case of the latter two hubs, spreads were above 1 €/MWh on around 80% of the trading days.

As Figure 29 shows, price integration in the CEE region has improved in recent years with spot price spreads lower than 1 €/MWh on more than 80% of trading days throughout the region in 2018. One of the crucial drivers of price integration are recent infrastructure developments that enabled flows in the West to East direction. This so-called reverse flow firm capacity was instrumental for gas supply competition in the region; shippers active in the region started sourcing from NWE hubs and NWE suppliers entered the market, which put previously dominant suppliers under pressure to offer similar price indexation of LTCs as available in NWE. As the price effects of competition spread in the region, so did hub price convergence.

Figure 29: CEE Hubs Spot Price Convergence (Trading Days Within Given Price Spread Range, %) – 2016 to 2018



Note: Spreads in €/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

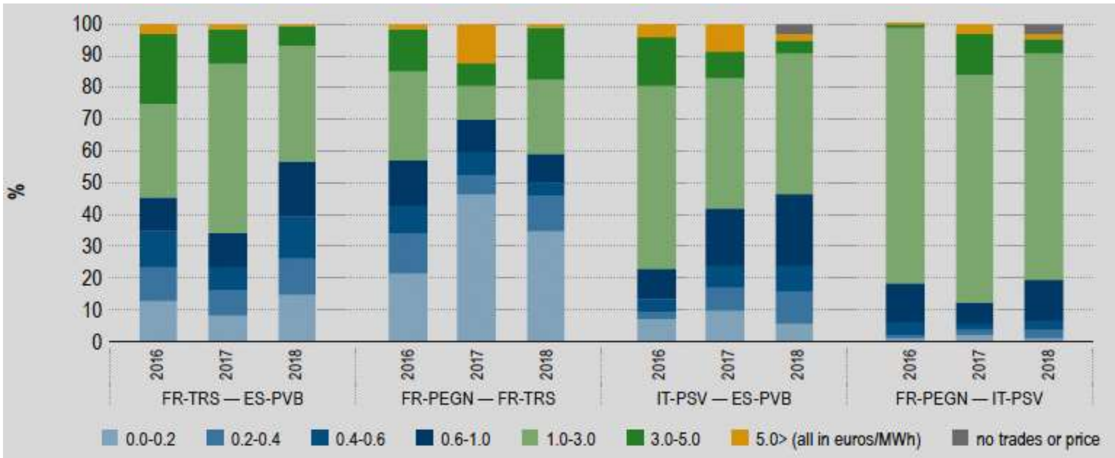
Sources: ACER (2019), ICIS Heren, Platts

The Austrian hub, which is the most liquid gas market in the region, is a reference point for prices as well as a source of supply for neighbouring markets. However, local supply and demand fundamentals are becoming better reflected in hub prices in the region, for instance in the Hungarian MGP, which is becoming a supply source in its own right, with suppliers active in neighbouring Ukraine, Romania and Croatia likely sourcing some volumes at the Hungarian hub.

In 2018, the trend of price integration between CEE hubs continued, with Czech hub prices converging with CEE hubs at the expense of its convergence with NWE hubs. The Slovak – Austrian spot spread remained tight but some high spread days reoccurred, in particular in the late days of February and early March when gas markets in the EU were highly volatile due to unprecedented cold weather.

While convergence of Mediterranean hubs, both with NWE hubs and among themselves, is still somewhat lower, it has improved in 2018, as Figure 30 shows. With the merger of the French PEGN and TRS hubs, there is now one price for the entire French system, which could have a positive impact on the Spanish hubs price convergence with the rest of the IGM.

Figure 30: Mediterranean Hubs Spot Price Convergence (Trading Days Within Given Price Spread Range, %) – 2016 to 2018



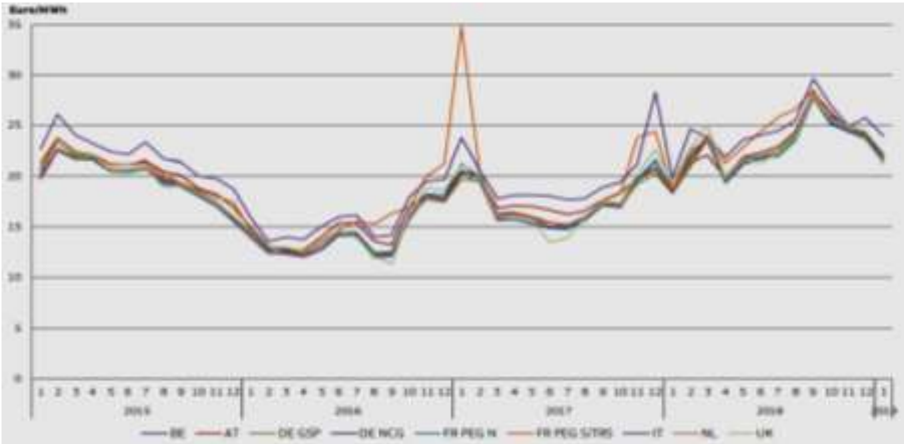
Note: Spreads in €/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

Sources: ACER (2019), ICIS Heren, Platts

According to the Quarterly Report on European Gas Markets published by the European Commission, European hub prices were averaging around 24-26 €/MWh in the fourth quarter of 2018, which was lower than the five-year peak in September 2018 (27-29 €/MWh), but it was higher than the range in Q4 2017 (19-22 €/MWh). In fact, in the fourth quarter of 2018, hub prices were up by 16-31% in year-on-year comparison. The average TTF hub price increased by 28% on Q4 2018.

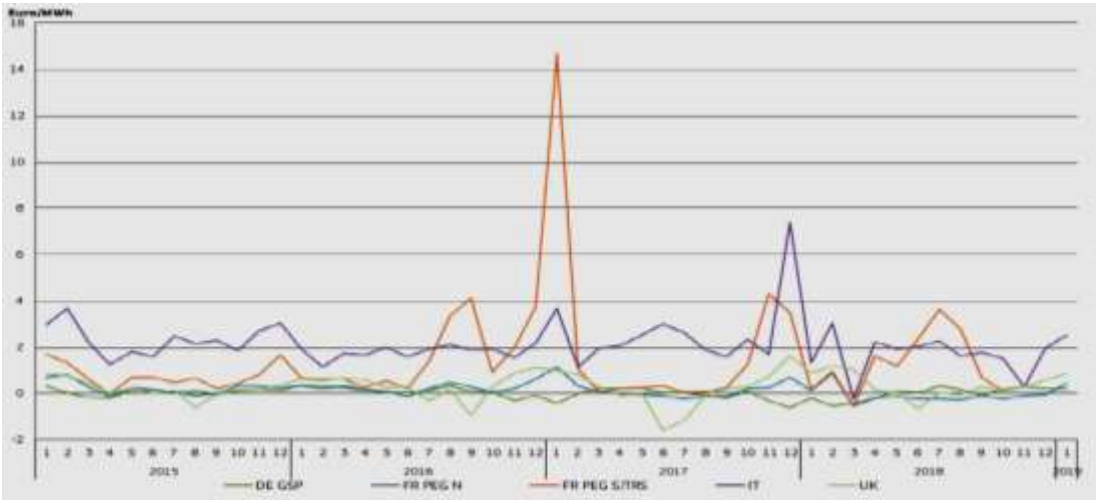
The main factors impacting the decrease in wholesale gas prices in the fourth quarter of 2018 were the generally decreasing energy commodity prices, namely crude oil and coal prices. Moreover, strong increase in LNG imports resulted in abundant gas supplies in Europe, which impacted the price level as well. A milder than usual weather in Q4 2018 across much of Europe weighed on gas demand for heating, having a lowering impact on sport prices. Figure 31 shows the development of forward prices one, two and three years ahead in comparison to the development of the day-ahead price on the Dutch TTF.

Figure 31: Wholesale Day-Ahead Gas Prices on European Gas Hubs



Source: European Commission, Quarterly Report on European Gas Markets (Vol. 11)

Figure 32: Premium of Wholesale Day-Ahead Gas Prices at Selected Hubs Compared to TTF



Source: European Commission, Quarterly Report on European Gas Markets (Vol. 11)

2.6. Impact of Gas Trading Hubs in European Gas Market Expansion and Integration

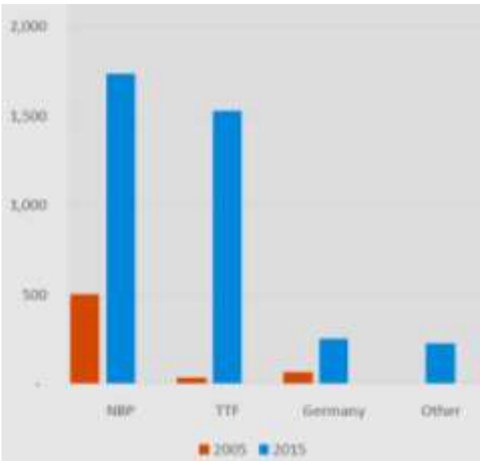
The emergence of gas trading hubs in Europe resulted from government policies to promote more competitive gas markets, along the lines of those in the United States. The movement toward more gas trading hubs and competitive gas markets was also abetted by the need to decouple long-term contracts from oil pricing, by the increase in gas supply through LNG imports, and by new pipelines from the North Sea and Russia. This development echoes what happened in the United States in the 1980s and early 1990s, when supply abundance and a nascent spot market for gas prompted the development of gas trading hubs.

There are significant differences between gas markets in Asia Pacific, the United Kingdom, and the EU. Natural gas markets in continental Europe and the United Kingdom operate in a highly connected pipeline network. LNG imports, while important, are additional entry points into this network. Asia Pacific, on the other hand, is not interconnected for obvious geographical reasons and LNG is the principal source of natural gas for the countries there. Prevailing LNG contracting practices, particularly in long-term contacts, which include linkages to oil prices, are not conducive to the development of gas trading hubs. In addition, Asia Pacific has no regulatory body similar to OFGEM or the European Commission that can lead the effort to liberalize markets and promote integration in the same way as has been done in Europe. Rather, each country has developed its own regulatory regime and is pursuing its own policies to promote competition. Indeed, the lack of maturity of some European gas trading hubs can be attributed in part to the European Commission's incomplete success in overcoming national monopolies and regulatory practices.

Gas trading hubs take several years to develop and usually require: (a) political and regulatory framework to encourage sales and purchased at a competitive price, (b) third-party access to import, storage and transport infrastructure with defined balancing rules, (c) standardized physical and financial contracts, (d) market transparency and confidence, provided through an organized exchange and (e) active market participants to boost the trading volume and increase the liquidity.

Gas trading hubs are mostly regional but interact across states and with global trade. Gas trading hubs also provide price signals that usually reflect short-term balancing dynamics and complement long-term pricing of international flows. Trading hubs help to optimise physical supply and demand to ensure gas gets to where it is required. In order to understand the important role of gas trading hubs in European gas market expansion and integration, we compared Europe's total executed traded gas volumes in 2005 and in 2015. In 2005, the total executed traded gas volume in Europe reached about 600 bcm, dominated by the first EU established gas trading hub (i.e. UK NBP), but in 2015 this figure stood at 3.731 bcm, which means an increase by 6 times in 10 years and a substantial rise in gas trading locations.

Figure 33: Europe's Total Executed Traded Gas Volumes (bcm), 2005 and 2015



Source: Gazprom

European Gas Target Model

Following the 18th Madrid Forum in 2010[15], the Council of European Energy Regulators (CEER) developed a vision for the European Gas Target Model (GTM). The GTM was geared towards creating a coherent framework from the various streams of policy under development by European energy regulators and the European Commission, with a view to implementing the Third Energy Package[16] and establishing a functioning internal market.

The implementation of the Third Energy Package with respect to gas markets is consistent with the evolution envisaged in the GTM, and covers matters such as the full unbundling of network operators, the establishment of congestion management procedures (CMP) and the development of Network Codes (NCs), e.g. for capacity allocation mechanisms in gas transmission systems (CAM NC), gas balancing (Balancing NC), interoperability and data exchange (Interoperability NC) and tariff structure harmonisation (Tariff NC). For European energy regulators, the implementation of the Third Energy Package, as well as the continuing development and implementation of the Framework Guidelines and binding Network Codes, remain key priorities.

In general, the market model implemented under the Third Energy Package, which was formalised in the 2011 CEER Gas Target Model **(13)** and later renewed and updated in the 2015 ACER Gas Target Model **(14)**, has proved its worth. The creation of entry-exit zones has led to the emergence of functioning gas trading hubs, while the harmonised rules for capacity booking and for the design of balancing markets have fostered liquidity in many wholesale markets in Europe. Gas market integration has improved in Europe over the last few years and gas wholesale prices have showed increasing levels of convergence in many hubs.

However, some problems remain. Some gas trading hubs are still illiquid, market concentration is still very high in many EU member states and some of them are completely dependent on a single supply source. In several European gas trading hubs, prices are structurally higher than in the reference markets of TTF and NBP. Moreover, new challenges may put at risk the recognised achievements of the Gas Target Model also in the regions which have so far achieved the best results. First of all, there may be the risk that the possible decrease of gas consumption (forecasted in some scenarios on the basis of the decarbonisation policies) and the termination of long-term capacity contracts (between 2026 and 2036 the majority of the existing long-term contracts are set to expire) could bring

[15] In 2010, the 18th Madrid Forum, a semi-official body set up by the EU Commission and consisting of all stakeholders active in the gas market (i.e. regulators, TSOs, suppliers, consumers, traders, member states representatives and the EU Commission), initiated consultations with the aim of achieving a common understanding of the Third Energy Package and its impact on the European gas markets.

[16] The term "Third Energy Package" refers collectively to: Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 (Gas Directive); Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 (Electricity Directive), concerning common rules for the internal market in natural gas and electricity respectively; Regulation (EC) No 714/2009 of the European Parliament and the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003; Regulation (EC) No 715/2009 of 13 July 2009 of the European Parliament and the Council on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005; and, Regulation (Ec) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators.

back higher hub price differentials, reducing the currently high market liquidity. A detailed analysis of future developments is certainly necessary to understand the extent of the risks and opportunities involved but, from the perspective of a potential future gas legislative package, we can already start reflecting on the possible options for addressing the issue.

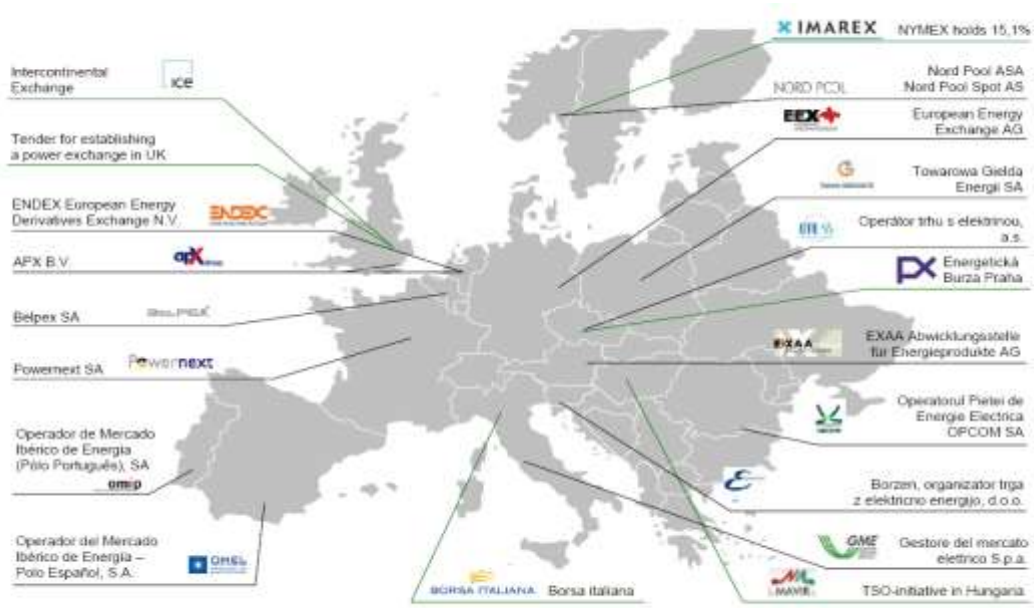
Based on the aforementioned factors, IENE addresses the possible need for updating the gas market design, especially in the wider region of SE Europe. This might be needed given that the current and future changes in the regional gas scene would have a deep impact on the gas dynamics. Hence, the question on the design of the gas target model could be reopened, especially on the functioning of hubs and interconnections, in particular regarding the tariff structures.

3. European Energy Exchanges and Their Role in Promoting Gas Trade

3.1. European Energy Exchanges

The list of power markets in Europe is large. It is composed of a group of regional power markets, which are more or less physically connected. These markets operate under the umbrella of the Electricity Regional Initiative launched back in 2006 and introduced the transition into a single, integrated energy market. Each of the 7 regions is monitored by a different entity and a vital part of their unification work is to help establish wholesale markets for electricity.

Map 10: Energy Exchanges Across Europe



Source: EUROPEX

The most relevant exchanges operating in these regions (and which increasingly overlap their products) are organized in an Association called the EUROPEX, i.e. the Association of European Energy Exchanges, which currently has 26 members. The most significant Energy Exchanges in Europe are:

3.1.1. NASDAQ OMX Commodities

www.nasdaqomxcommodities.com

It is one of the largest and most active energy exchanges in Europe, located in Norway (since 2002), and operating in Sweden, Finland and Denmark, and present in Germany and the United Kingdom. The NordPool Spot AS operates the spot market for electricity, while Nasdaq OMX Commodities provides trading and clearing of Nordic and international power derivatives, European Union allowances (EUAs) and certified emission reductions (CERs).

The products traded at NASDAQ OMX Commodities Europe’s financial market comprise of Nordic, German, Dutch and UK power derivatives, European Union allowances (EUA) and certified emission reductions (CER). The derivatives are base and peak load futures, Deferred Settlement Futures (DS Futures), options, and Electricity Price Area Differentials (EPAD).

These contracts are used for trading and risk management purposes, and have a current trading time horizon of up to six years. Base load contracts are delivered Mon-Sun, 00.00–24.00 during the length of the contract. Peak load contracts are delivered Mon-Fri, 08.00 – 20.00 during the length of the contract. The reference price is the Nordic system price (NordPool for Scandinavian coutries), EEX Phelix (Germany), APX ENDEX (Holland) and N2EX (UK). There is no physical delivery of financial market electricity contracts. Cash settlement is made throughout the trading- and/or the delivery period, starting at the due date of each contract, depending on whether the product is a futures or DS Future. Financial contracts are entered without regard to technical conditions, such as grid congestion, access to capacity, and other technical restrictions.

In addition, NASDAQ OMX Commodities offers Emissions trading derivative products, such as EUA/CER day futures, EUA/CER futures, EUA DS Futures and EUA/CER option contracts. All emission contracts have physical delivery. A clearing service for EUAs and CERs traded over-the-counter (OTC) is also available.

The clearinghouse is the contractual counterparty in all contracts traded at NASDAQ OMX Commodities Europe’s financial market. Clearing guarantees the financial settlement. The daily settlement is automatic, and members are connected to the settlement system through a variety of multinational settlement banks.

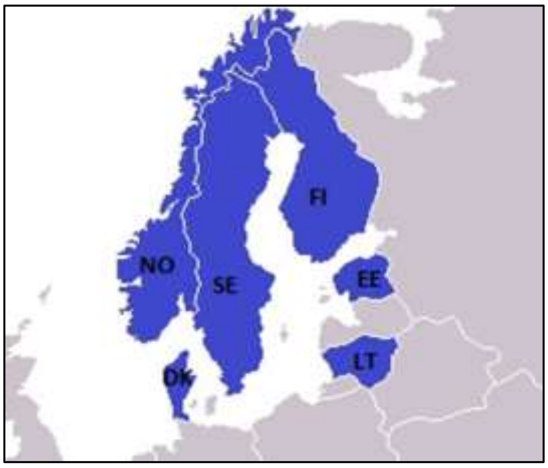
3.1.2. Nord Pool Spot

www.nordpoolspot.com

The Nord Pool Spot power exchange operates under the company Nord Pool Spot AS, market operator of the electricity market of the Scandinavian peninsula and some neighboring countries.

The Nord Pool Spot was the first market trading power in the world. Today, it is still one of the biggest markets in the world of its kind, and has negotiated the purchase and sale of energy in the Nordic region, as well as Estonia, Germany and Great Britain. 74% of total energy production in the Nordic region is traded here. The rest is traded through bilateral contracts between suppliers, retailers and end consumers.

Map 11: The Electricity Market of Nord Pool Spot



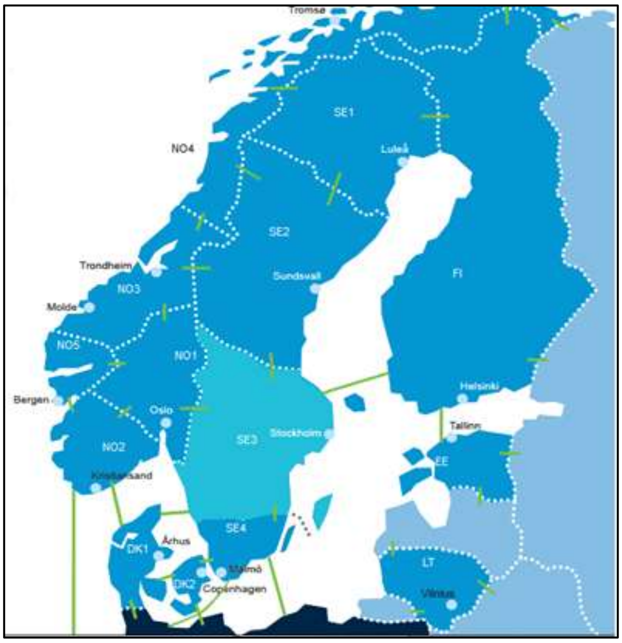
Source: Nord Pool Spot

The Nord Pool Spot offers the ability to trade spot electricity both in day-ahead and intraday contracts. 370 companies from 20 countries trade on the exchange. The Nord Pool Spot Group has offices in Oslo, Helsinki, Stockholm, the Fredericia (Denmark), Tallinn and London. The Nord Pool Spot is one of the Nordic transmission system operators.

Shareholders of Nord Pool Spot AS are the corresponding TSOs of the countries, except Estonia and Lithuania.

The market which the operation of Nord Pool Spot power exchange covers is divided in some areas (market areas), otherwise bidding areas. This division is decided by the electricity TSOs of each country and is decided in order to better manage congestion in the flow of electricity to the transmission grid (congestion management). The market areas for the power exchange Nord Pool Spot are shown in Map 12.

Map 12: Market Areas of Nord Pool Spot



Source: Nord Pool Spot

As shown in Table 6, the market areas of Nord Pool Spot do not coincide with the territory of the countries covered by the operation. Instead, each country has been divided into more than one market area. The TSOs involved in market operations are presented in Table 7.

Table 6: Market Areas of Nord Pool Spot

Countries	Market Areas				
Norway (NO)	NO1	NO2	NO3	NO4	NO5
Denmark (DK)	DK1		DK2		
Finland (FI)	FI				
Sweden (SE)	SE1	SE2	SE3	SE4	
Estonia (EE)	EE				
Lithuania (LT)	LT				
Latvia – Estonia Borders	ELE (Virtual area)				

Source: Nord Pool Spot

Table 7: TSOs Involved in the Operation of Nord Pool Spot

County	Electricity Transmission System Operators (TSOs-E)
Norway	Statnett Sf
Sweden	Svenska Kraftnat
Finland	Fingrid Oyj
Denmark	Energinet.dk
Estonia	Elering AS
Lithuania	LITGRID AB

Source: Nord Pool Spot

Transactions are carried out in two complementary markets - Elspot for day-ahead transactions and Elbas for intraday trading. In the Elspot, contracts to buy and sell electricity for delivery to one of the market areas of Nord Pool Spot, and in interconnected regions, are traded.

Table 8: Main 2018 Figures (TWh) of the Energy Market of Nord Pool Spot

Nord Pool Spot AS	2018
Traded volume	524
UK day-ahead market	120
Nordic, Baltic and German intraday market	8.3
Nordic and Baltic day-ahead market	396

Source: Nord Pool Spot

3.1.3. EEX (European Energy Exchange)

www.eex.com

The European Energy Exchange (EEX), based in Leipzig, was founded in 2002 as a result of the merger of the two German power exchanges in Frankfurt and Leipzig. Since then, EEX has evolved from a pure power exchange into the leading trading market for energy and related products with international partnerships.

In the field of electricity trading, EEX has entered into a close cooperation with the French Powernext. As part of their cooperation the two power exchanges unified Spot markets and derivatives.

German and French power derivatives are traded through the EEX Power Derivatives GmbH, the majority of which is owned by EEX. To strengthen the position of EEX, the clearance activities have been transferred to the subsidiary European Commodity Clearing (ECC). Clearing and settlement for both spot and derivative transactions are provided by the ECC, which already settles transactions of natural gas traded on Powernext since November 2008. Today, ECC is the largest clearing house of energy and related products in Europe and acts in collaboration with six power exchanges.

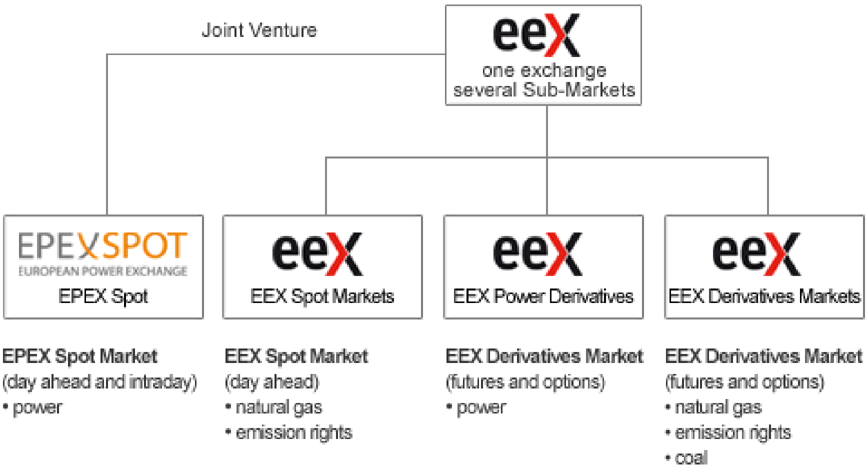
The Derivatives market offers financially settled power futures for Germany/Austria (Phelix Futures) and France (French Futures) as well as options on Phelix Futures. Maturities offered for trading comprise Day, Weekend, Week, Month, Quarter and Year Futures. In addition to the settlement of transactions concluded on the exchange, clearing of registered trades is possible.

Natural gas Market

In 2007, the EEX began trading natural gas in Germany. It operates a spot and a derivatives market for the German market areas GASPOOL and NetConnect Germany (NCG), while it expanded with the TTF market area at the end of May 2011. In 2012, the subsidiary EGEX - European Gas Exchange was created, where trading activities for gas are carried out.

The Sub-Markets of the European Energy Exchange are:

Figure 34: The Sub-Markets of EEX



Source: EEX

The products traded on the European Energy Exchange are:

Table 9: Products Traded in EEX

	Spot market	Derivatives Market	Trade Registration
Electricity	**EPEX Spot** • Day-Ahead Auction (D/A, F, CH) • Intraday (D, F)	**EEX Power Derivatives** • Phelix Futures (D/A) • French Futures (F) • Phelix Options (D/A) • Guarantees of Origin • Hydro: Alpine region, Nordic region • Wind: Northern Continental Europe	**EEX Power Derivatives** Relevant products Power Futures (Romania, Scandinavia, Poland, Italy, Spain, Portugal, Switzerland)
Natural gas	**EEX** • Global gas spot contracts (GASPOOL, NCG, TTF) • Spot contracts quality-specific H- and L-gas (GASPOOL, NCG) • Day contracts • Weekend contracts	**EEX** Physical Futures (NCG, GASPOOL)	**EEX** Relevant products Gas Futures (NBP) Gas Futures (IT)
Emission rights CO_2	**EEX** EUA EUAA CER Primary Auction EUA Primary Auction EUAA	**EEX** EUA Futures CER Futures EUA Options EUA Primary Auction	**EEX** All spot products All derivatives products
Coal	/	**EEX** Financial Futures (ARA, RB)	**EEX** Coal Futures

Source: EEX

Table 10: 2018 Activity Results of EEX

		2018	2017	Change %
Profit and loss account				
Sales revenue	kEUR	267,654	225,320	+19
Earnings before interest, taxes, depreciation and amortisation (EBITDA)	kEUR	111,612	88,938	+25
Earnings before interest and taxes (EBIT)	kEUR	91,977	73,486	+25
Earnings before taxes (EBT)	kEUR	92,106	74,224	+24
Balance sheet (as of 31 December)				
Non-current assets	kEUR	368,320	347,757	+6
Equity	kEUR	474,135	425,806	+11
Balance sheet total	kEUR	7,117,397	3,561,371	+100
Core business parameters				
Spot market				
Power spot market volume[1]	TWh	577	543	+6
Gas spot market volume[2]	TWh	1,111	828	+34
Emissions spot market volume	mt*	923	908	+2
Derivatives market				
European power derivatives market volume[3]	TWh	3,347	2,822	+19
US power derivatives market volume[4]	TWh	1,039	395	+163
Gas derivatives market volume[2]	TWh	852	1,154	-26
Emissions derivatives market volume	mt*	1,973	472	+318
Agriculturals derivatives market volume	Contracts	60,251	65,453	-8
Freight derivatives market volume—futures and options	kd**	230	473	-51
Company parameters				
Trading participants		635	588	+8
Employees (balance sheet date)		586	542	+8

* Million tonnes
** Thousand days

[1] EPEX SPOT trade volumes, including SEEPEX and PXE volumes
[2] PEGAS trade volumes, including Gaspoint Nordic, PXE and CEGH volumes
[3] Trade volumes, including PXE volumes
[4] Nodal trade volumes from May 2017

Source: EEX

3.1.4. Powernext

www.powernext.com

Powernext is the power exchange in France, based in Paris and founded in 2001, with the original shareholders being HGRT, Euronext, EDF, Societe Generale, BNP Paribas, TotalFinalElf and Electrabel.

Powernext SA manages several complementary, transparent and anonymous energy markets:

- **Powernext Gas Spot** and **Powernext Gas Futures** launched on November 26, 2008 in order to hedge volume and price risks for natural gas in France. On July 1, 2011, GRTgaz and Powernext launched the first gas market coupling initiative in Europe between GRTgaz's PEGs Nord and Sud. Powernext launched on February 1, 2013 a natural gas Futures market on the TTF hub in the Netherlands.
- Powernext and EEX launched **PEGAS** on May 29, 2013, a commercial cooperation where the 2 exchanges combine their gas markets to create a pan-European gas market.

- **Powernext Energy Savings**, a dedicated spot market for French White Certificates (Certificats d'Economies d'Energie) launched on January 10, 2012.
- Powernext owns a 50% equity stake in EPEX SPOT and a 20% in EEX Power Derivatives.

In November 2006, the Trilateral market coupling (TLC) between French, Belgian and Dutch electricity markets was launched. The TLC is a cooperation between the three power exchanges (i.e. APX, Powernext, Belpex) and the three transmission system operators (i.e. Elia, RTE, TenneT).

Powernext Intraday market for electricity to be delivered on the French hub managed by RTE was launched in 2007. In the same year, Powernext Carbon was sold to NYSE Euronext and NYSE Euronext sold its shares in Powernext to HGRT.

In November 2008, NYSE Euronext leaves the capital of Powernext and sells its 34% shares in Powernext to HGRT. At the same time, BNP Paribas and Société Générale withdraw from the capital of Powernext and GDF Suez, TIGF and GRTgaz become shareholders of Powernext. In December 2008, Powernext Day-Ahead, Powernext Intraday, market coupling staff and activities are transferred into EPEX Spot SE. Powernext holds a 50% stake in this new company.

In April 2009, EPEX Spot transfers the clearing activity for French Power Products (Day-Ahead and Intraday) from LCH.Clearnet SA to ECC (European Commodity Clearing AG), Powernext transfers French Power Futures market (Powernext Futures) into EEX Power Derivatives GmbH along with its 44 trading members. Powernext acquires in return a 20% stake in EEX Power Derivatives.

In January 2012, Powernext launched Powernext Energy Savings, a spot market for Energy Saving Certificates (Certificats d'Economies d'Energie or CEE in French). In February 2013, Powernext Gas Futures launched monthly, quarterly, seasonal and yearly contracts on the Dutch TTF hub, as well as a PEG Nord/TTF Spread product.

Powernext started as a regulated investment firm based in Paris and operating under the "multilateral trading facility" (MTF) status and in February 2014, it became a Regulated Market.

In 2015, Powernext became part of EEX Group, while in 2016 there was an integration of spot and futures products of Central European Gas Hub (CEGH) and Gaspoint Nordic into the PEGAS platform. One year later, time spread products on PEGAS Futures launched, while in 2018, Powernext was re-appointed to operate the French Registry for Guarantees of Origin for another 5 years. Powernext introduces auction system for GOs issued by subsidised production devices.

Currently, 48 employees are working for the Powernext in the IT, legal, regulatory, administration, finance, product and business development, communication and sales functions. Among 9 countries of activity, Powernext has now 245 members.

PEGAS – Pan-European Gas Cooperation

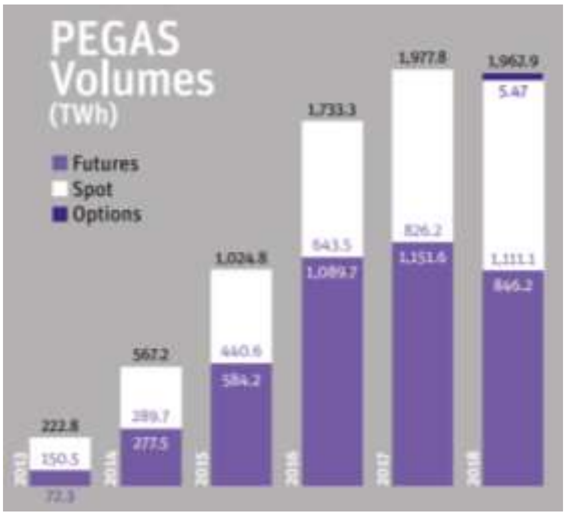
PEGAS is a cooperation between European Energy Exchange (EEX) and Powernext. In the framework of this cooperation, both companies combine their natural gas market activities to create a pan-European gas market.

Members benefit from one common gas trading Trayport platform with access to all products offered on the exchanges: spot and derivatives products for the German, French and Dutch market areas. Furthermore, spread products between these market areas are offered on the same trading platform.

In the framework of the PEGAS cooperation, participants have the possibility to trade natural gas contracts for the market areas TTF, NCG, GASPOOL and PEG on the same trading platform. The product range of the cooperation covers Spot as well as Derivatives market products and combines the EEX and Powernext market areas. In this context, PEGAS offers the opportunity not only to trade within one market area but also to trade spread products between these market areas.

PEGAS gives market participants access to all gas trading products on both exchanges and, for the first time, it also gives them an opportunity to trade price differences between the market areas, so-called location spreads. In 2018, about 1,963 TWh were traded on PEGAS.

Figure 35: PEGAS Volumes (2013-2018)



Source: Powernext

3.1.5. EPEX Spot SE

www.epexspot.com

EPEX SPOT was created in 2008 through the merger of the power spot activities of the energy exchanges Powernext SA in France and EEX AG in Germany. In 2015, EPEX SPOT integrated with APX Group. EPEX SPOT SE equity capital is divided between EEX Group, including Powernext (51%), and HGRT (49%), a holding composed of the transmission system operators Amprion, APG, Elia, RTE, Swissgrid and Tennet.

The European Power Exchange EPEX SPOT covers Germany, France, United Kingdom, the Netherlands, Belgium, Austria, Switzerland and Luxembourg, representing 50% of European electricity consumption.

Figure 36: Shareholder Structure of EPEX Spot

Source: EPEX Spot

EPEX Netherlands

Established in 1999, under the name APX Power NL, APX was an independent fully electronic exchange for anonymous trading on the spot market, offering distributors, producers, traders, brokers and industrial end-users a spot market trading platform for day ahead transactions (trading today for delivery of electricity tomorrow) as well as Intraday transactions for on-the-day trading. In 2015, APX Group integrated their business with EPEX SPOT in order to form a Power Exchange for Central Western Europe (CWE) and the UK. Renamed EPEX Netherlands, APX Power NL now operates under the EPEX SPOT brand name and continues to provide its members standardised products to sell and purchase, remaining the central counter party in all electricity trades.

EPEX SPOT in the UK

Established in 2000 as Britain's first independent power exchange, former APX Power UK (prior to this named UKPX) offered an anonymous marketplace for integrated trading, clearing and notification for spot and prompt power contracts and a trading platform for cleared forwards contracts in the UK. Since the integration of the businesses of the APX Group and EPEX SPOT, APX Power UK operates under the EPEX SPOT brand name, remaining the cornerstone of the UK spot market and is used by members on a 24/7 basis for the majority of their within day balancing requirements.

EPEX SPOT Belgium

Former Belpex was the short term, physical power exchange for the delivery and off-take of electricity on the Belgian hub. As a full subsidiary of APX, Belpex integrated with EPEX SPOT in 2015 and now operates as EPEX SPOT Belgium under the EPEX SPOT brand name. EPEX SPOT facilitates anonymous, cleared trading in two different market segments, namely the Day-Ahead market segment (DAM) and the Continuous Intraday market segment (CIM). The

Belgian EPEX SPOT (formerly Belpex) Day-Ahead and Intraday markets are coupled with the respective markets in the Netherlands, France and Germany, the Belgian intraday market is connected with the intraday markets in the Netherlands, Germany, France, Austria and Switzerland. As Figure 37 shows, 567 TWh were traded on EPEX SPOT's power markets in 2018, recording an increase of 5.98%, compared to 2017 levels. More specifically, EPEX SPOT reached 82 TWh of traded volumes on its Intraday markets and 485 TWh on its day-ahead markets in 2018.

Figure 37: Traded Volumes of EPEX Spot, 2017 and 2018

Source: EPEX Spot

3.1.6. Gestore Dei Mercati Energetici S.P.A (GME) – Italian Power Exchange

www.mercatoelettrico.org/En/

Gestore dei Mercati Energetici S.p.A, the power exchange in Italy, is active since 2004. It was established in response to the attempt of the government to liberalize the domestic energy market and to attract the interest of foreign investors.

The electricity market, named **Italian Power Exchange (IPEX)**, allows producers, consumers and wholesale market participants to buy and sell electric power on an hourly basis.

The electricity market consists of:

1. the Spot Electricity Market (MPE), which includes:

    (a). The **Electricity Day-Ahead Market (MGP),** which is an auction market (and not a continuous-trading market), where producers, wholesalers and eligible end users can buy or sell electricity for the next day. The GME is a central counterparty to transactions concluded on the market MGP. In the MGP, hourly energy blocks are traded for the next day. The MGP sitting opens at 8 a.m. of the ninth day before the day of delivery and closes at 9:15 a.m. of the day before the day of delivery. The results of the MGP are made known within 10:45 a.m. of the day before the day of delivery. The accepted demand bids pertaining to consuming units belonging to

Italian geographical zones are valued at the "Prezzo Unico Nazionale" (PUN – national single price); this price is equal to the average of the prices of geographical zones, weighted for the quantities purchased in these zones.

(b). The **Electricity Intra-Day Market (MI),** where producers, wholesalers and eligible end users can alter the timing of the introduction or withdrawal of energy from the system in relation to what has been determined in buying MGP. The GME is a central counterparty to transactions concluded on the market MI.

(c). The **Ancillary Services Market (MSD)** is the venue where Terna S.p.A. (Italian energy TSO) procures the resources that it requires for managing, operating, monitoring and controlling the power system (relief of intra-zonal congestions, creation of energy reserve, real-time balancing). In the MSD, Terna acts as a central counterparty. Accepted bids/offers are valued at the offered price (pay-as-bid). The MSD consists of a scheduling stage (ex-ante MSD) and of the Balancing Market (MB). The ex-ante MSD and the MB take place in multiple sessions.

2. The futures market for electricity with the undertaking of delivery/receipt (JSC), where participants can sell/ buy future supplies of electricity. The GME is a central counterparty to trades concluded in the JSC.
3. The platform for physical delivery of financial contracts concluded in **IDEX (CDE)**, where financial derivatives of electricity are traded. The IDEX is the financial derivatives segment of IDEM, the Italian Derivatives Markets managed by Borsa Italiana SpA where financial derivatives of electricity are traded. Contracts executed in CDE are those for which the Participant has requested to exercise his right to physical delivery in the electricity market.

Moreover, GME also manages the **OTC Registration Platform (PCE)** for registration of forward electricity purchase/sale contracts that have been concluded off the market.

GME is also assigned, on an exclusive basis, with the organization and economic management of **natural-gas markets**, which consist of the Platform for the trading of natural gas (P-GAS), the Gas Market (MGAS) and the Gas Balancing Platform (PB-GAS), as well as the management of physical forward gas markets.

In the MGAS, parties authorized to carry out transactions at the "Punto Virtuale di Scambio" (PSV - Virtual Trading Point) may make forward and spot purchases and sales of volumes of natural gas.

In the MGAS, GME plays the role of central counterparty to the transactions concluded by Market Participants.

Table 11: Electricity Prices and Traded Volumes in the Italian Power Exchange

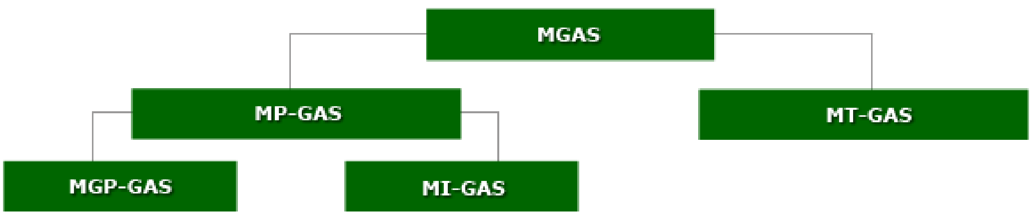
Year	purchasing price - National Single Price PUN (€/MWh)			total volumes (MWh)	liquidity (%)	no. of participants at 31 Dec
	average	min	max			
2004	51,6	1,1	189,2	231.571.983	29,1	73
2005	58,6	10,4	170,6	323.184.850	62,8	91
2006	74,8	15,1	378,5	329.790.030	59,6	103
2007	71	21,4	242,4	329.949.207	67,1	127
2008	87	21,5	212	336.961.297	69	151
2009	63,7	9,07	172,3	313.425.166	68	167
2010	64,1	10	174,6	318.561.565	62,6	198
2011	72,2	10	164,8	311.493.877	57,9	181
2012	75,5	12,1	324,2	298.668.836	59,8	192
2013	63	0	151,9	289.153.546	71,6	214
2014	52,1	2,2	149,4	281.997.370	65,9	251
2015	52,3	5,6	144,6	287.132.081	67,8	259
2016	42,8	10,9	150	289.700.706	70	253
2017	53,9	10	170	292.197.128	72,2	254
2018	61,3	6,9	159,4	295.561.956	72	271

Source: GME

The MGAS consists of:

- **Day-Ahead Gas Market (MGP-GAS).** The MGP-GAS takes place under the continuous-trading mechanism. In the MGP-GAS, gas demand bids and supply offers, in respect of the calendar gas-day following the one on which the session ends, are selected;
- **Intra-Day Gas Market (MI-GAS).** In the MI-GAS, gas demand bids and supply offers, in respect of the gas-day on which the session ends, are selected.
- **Forward Gas Market (MT-GAS).** In the MT-GAS, gas demand bids and supply offers are selected from as many order books as the types of tradable contracts for the different delivery periods. The types of tradable products may be: yearly/thermal year, yearly/calendar year, half-yearly, quarterly, monthly and Balance-of-Month (BoM).

Figure 38: Market Structure of MGAS



Source: GME

For the purposes of the market:

a. The applicable period is the gas-day (period of 24 consecutive hours beginning at 6:00 a.m. of each calendar day and ending at 6:00 a.m. of the next calendar day);
b. The unit of measurement for the gas volume is the MWh/day, specified without decimals;
c. The unit of measurement for unit prices is the €/MWh, specified with three decimals.

Table 12: Natural Gas Prices and Traded Volumes in the Italian Power Exchange

	Continuous Trading				Auction		
Thermal Year	Average price (€/MWh)	Volumes (MWh)	Matchings (no.)	Sessions * (no.)	Average price (€/MWh)	Volumes (MWh)	Sessions * (no.)
October 2010/ September 2011	25,86	132.778	106	67/293	24,9	2.550	3/292
October 2011/ September 2012	29,46	151.150	72	53/366	-	-	0/366
October 2012/ September 2013	26,8	13.300	7	4/364	-	-	0/335
October 2013/ September 2014	-	-	-	0/365			
October 2014/ September 2015	-	-	-	0/365			
October 2015/ September 2016	-	-	-	0/366			
October 2016/ September 2017	18,98	2.427.875	1674	238/369			
October 2017/ September 2018	23,11	10.021.977	9078	318/402			

Source: GME

As part of the organization and economic management of the Electricity Market, GME is also vested with the organization of trading venues for **Green Certificates** (giving evidence of electricity generation from renewables), **Energy Efficiency Certificates** (the so-called "White Certificates", giving evidence of the implementation of energy-saving policies), **Emissions Allowances or Units** and organizes and manages systems for the trading of **guarantees of origin**. These systems include the regulated market (M-GO) and the platform for registration of bilaterals (PB-GO).

GME was also entrusted with the development, organization and operation of a market platform for the trading of **oil logistic services**, as well as with the related activity of collection of data on mineral-oil storage capacity. GME is responsible, among others, for the organization and management of a wholesale market platform for the trading of liquid oil products for the transport sector.

3.1.7. ICE Futures Europe

www.theice.com

ICE Global markets in clear view

ICE Futures Europe, based in London, is an organized and fully electronic futures exchange for global energy markets. On the ICE Futures Europe, half of the volume of futures trading of crude oil and refined products in the world are traded. The ICE also operates one of the leading European futures markets on emissions, gas, coal and electricity. Participants from more than 70 countries have access to a range of futures and options contracts. Transactions on ICE Futures Europe are cleared through ICE Clear Europe.

In the power market segment, it offers futures and OTC registration in the UK market. Futures contracts have daily, monthly and quarterly maturities at base and peak loads. Settlement refers to the physical delivery (debit/credit into Energy accounts).

3.1.8. OMI-POLO Español S.A. (OMIE)

The two Iberian countries (i.e. Spain and Portugal) decided in 2004 to proceed in the integration of energy markets and create a single entity called the OMI-Polo Español S.A. (OMIE), which belongs to the Operador del Mercado Ibérico (Iberian Market Operator) business group, whose business structure is shown in Figure 39.

Figure 39: Organizational Structure of OMIE

Source: OMIE

For this purpose, they created 2 Holding management/exchanges, the OMEL (Spain) and OMIP (Portugal), involving joint participation with 50% each in the share capital of

- OMEL (Spot trading market)
  - It operates with a mixed system and as a power exchange in the spot market.
- OMIP SGPS (Derivatives market)
  - It serves as a derivatives exchange and having a subsidiary clearing company (OMIP Clear).

Both exchanges have common members in both countries. Each member which gets approved by the local Energy Regulatory Authority automatically acquires the same membership status on the other exchange. It is also important to mention that they have a common Board which brings together the energy companies of the two countries, while the shareholders of both companies and up to 40% are the same as the energy companies of the two countries. There is a legal limit to individual ownership established at 5% of the capital, only the Spanish and Portuguese Transmission System Operators are allowed to hold up to 10% each of the capital of the company. Finally, the two exchanges are supervised by the Capital Market Commissions and Regulatory Authorities for Energy (RAE) of each country. In December 2015, OMIE was appointed Nominated Electricity Market Operator (NEMO) by the competent authorities.

In the OMEL, spot market transactions are being carried out in the day-ahead, the intraday market and balancing market.

In the OMIP, market derivatives products, such as futures, options, swaps and forward contracts, are traded.

Various types of futures are traded on OMIP:

- Spanish and Portuguese electricity.
- Baseload (24h) and spot charge (12h).
- With physical settlement and with financial settlement, where both types of contract benefit from a single order book.
- With maturities of days, weekends, weeks, months, quarters and years.

Besides providing a registration platform for OTC transactions to be cleared on OMIClear, for all these futures contracts, OMIP also allows the registration of forward and swap trades:

- Foreseeing for the former, physical delivery and settlement of VAT and for the latter, a purely financial settlement excluding VAT.
- Both on Spanish electricity
- With the same maturities as futures contracts.

OMEL has established a market for auctioning gas, which are being carried out periodically. Furthermore, in April 2012, OMEL and OMIP SGPS decided to launch the MIBGAS initiative for undertaking the work associated with the design and implementation of an operating model for the Iberian gas market, which pursuant to the guidelines contained in the European Gas Target Model adapts to the specific needs of the Iberian gas system.

Figure 40: 2018 Total Monthly Traded Volumes (Day-ahead and Intraday Markets)* at OMIE

**** Total energy negotiated in the daily market, intraday auctions and the continuous intraday market that came into operation on June 13, 2018.***

Source: OMIE

Figure 41: 2018 Key Figures at OMIE

Source: OMIE

3.1.9. OMI-Polo Português S.A. (OMIP)

OMIP is a Regulated Market Operator that provides, together with the OMIClear Clearing House, a trading platform for energy products to the market, as laid down in the International Agreement concluded between the Portuguese Republic and the Kingdom of Spain for the Iberian Electricity Market (MIBEL). As an institution, both OMIP and its activity are supervised by CMVM (the Portuguese Securities Market Commission), in accordance with the applicable national and European laws and regulations of the financial sector.

Under the Derivatives Market, products with electricity and natural gas as underlying assets are open to trading and with delivery in Portugal, Spain, France and Germany (futures, forwards, swaps, options, FTR), that are traded on a daily basis by agents based in Portugal, Spain, and in other European and non-European countries.

In addition to the Derivatives Market, OMIP offers other services, such as development, implementation, management and operation of market solutions in various areas, in particular energy and telecommunications. These services include auctions for allocating assets such as electricity, natural gas, wind energy production licenses, capacities in the Portugal-Spain electricity interconnection, capacities in the infrastructures of the National Natural Gas System, Special Regime Generation, and licenses to use radio spectrum, etc. In the energy retail market, it provides services in the switching of service provider. OMIP is part of the OMI Group, which also includes OMIClear, the Iberian Energy Clearing House, and OMIE, Iberian electricity spot market.

3.1.10. Romanian Power Exchange (OPCOM)

www.opcom.ro

The company Operatorul Pietei de Energie Electrica si Gaze Naturale "OPCOM" S.A. fulfills the role of the electricity market administrator, providing an organized, viable and efficient framework for the commercial trades' deployment on the wholesale electricity market and performs administration activities of the centralized markets in the natural gas sector.

The Romanian Power Market Operator-OPCOM S.A. was established in 2000, as a joint stock company subsidiary of the Romanian Transmission and System Operator - Transelectrica S.A. and is fully owned by it. The day-ahead electricity market, the intraday electricity market, the market for bilateral contracts awarded through public auction, the green certificates market and emission rights are the markets that operate in the energy exchange. At the same time, it operates an electronic auction platform for gas, which trades weekly, monthly, quarterly and annual contracts for the supply of natural gas.

Figure 42: 2018 Total Monthly Average Traded Volume and Price (Day-ahead Market) at OPCOM

Source: OPCOM

Figure 43: 2018 Total Monthly Average Traded Volume and Price (Intraday Market) at OPCOM

Source: OPCOM

3.1.11. EXAA - Austria

www.exaa.at

EXAA (Abwicklungsstelle für Energieprodukte AG) is Austria's energy and environmental exchange seated in Vienna. EXAA was founded on June 8, 2001 and opened for spot market trading in electric power on March 21, 2002. Since then, EXAA has developed into a major platform for efficiently exploiting the trading opportunities of the liberalized energy markets of Central Europe.

The significance of a trading venue is determined by its participants. On December 31, 2018, there were 73 companies from 14 countries trading on EXAA, with the share of foreign traders accounting for the majority today.

EXAA Energy Exchange Austria is a spot electricity market covering Austria and is active in the German market. It offers the ability to trade electricity for the next day (day-ahead), and from 2012 it began trading green electricity (Green Energy), i.e. the electricity that comes from certified renewable energy generators.

Starting out from the electricity spot market with physical fulfillment in the Austrian control areas, EXAA started enlarging trading in 2004 to include the German trading area. Since the end of 2009, EXAA has been offering physical delivery in all German control areas. In December 2012, EXAA was the first European power exchange to introduce a green electricity product with physical delivery under the brand name GreenPower@EXAA.at. In the autumn of 2014, EXAA enlarged its spot auction by a new product: trading in quarter-hours. In the past business years, EXAA successfully implemented the EU REMIT Regulation and in October 2015, it launched a reporting platform for sending national trade data to the national regulator, E-Control, and European trade data to the European regulatory authority ACER.

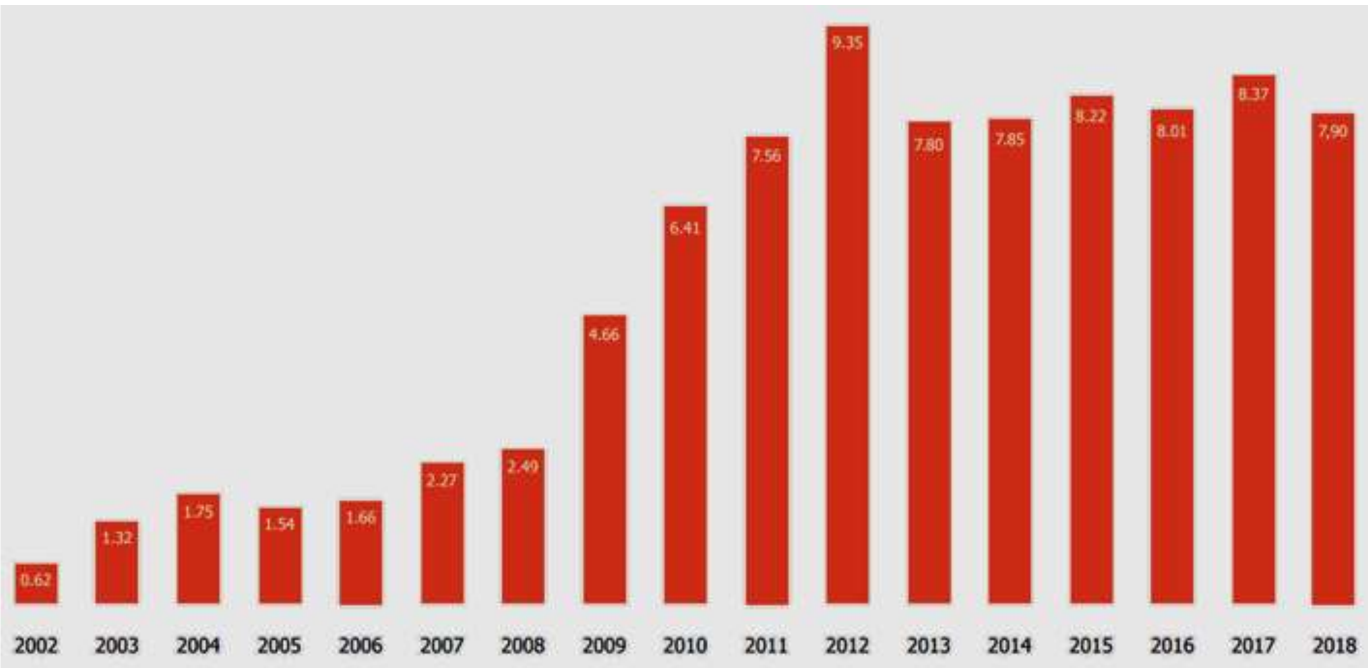
All 24 hours of the day are defined as individual trading products. This enables trading participants to cover their daily demand as best as possible through trading on the exchange. The minimum trading volume is 0,1 MWh. Furthermore, the volumes can be traded in intervals of 0,1 MWh. The order prices are entered in € with two decimal places. Since market launch, several block products (combination of several consecutive hours to one block) were introduced. Block products give exchange members higher security with respect to the uninterrupted buying and selling of electricity for several hours.

Figure 44: Different Block Products Traded in EXAA

Source: EXAA

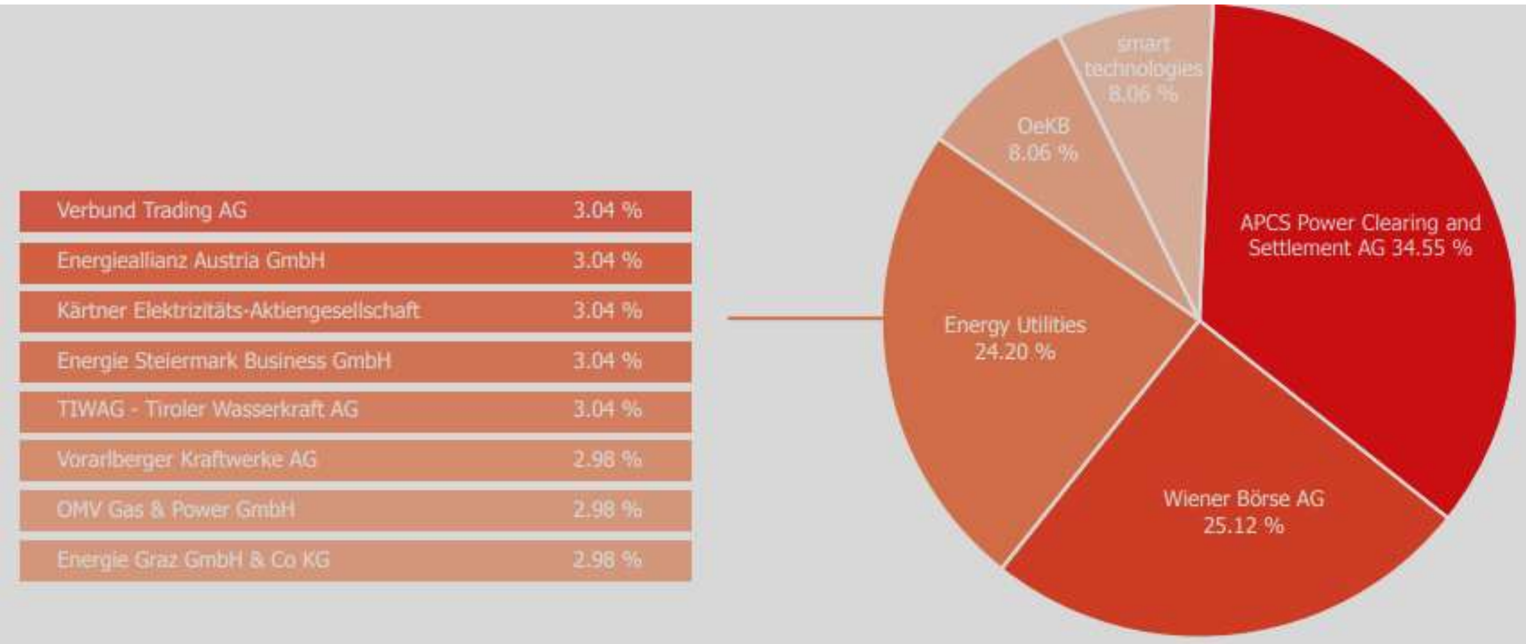
The product range of EXAA consists of 24 single hours and tradable standardized blocks, which are included in the hourly auction.

Figure 45: 2002 - 2018 Traded Volumes (TWh) in EXAA



Source: EXAA

Figure 46: EXAA's Shareholder Structure



Source: EXAA

3.1.12. CEGH Gas Exchange

cegh.at

Central European Gas Hub AG (CEGH), located in Vienna, Austria, is the leading hub for trading gas from the east to the west. As the operator of the Virtual Trading Point, CEGH offers international gas traders a gateway for trading in the entry/exit zone of the Austrian market. In 2018, CEGH achieved a total trading volume of 659 TWh of natural gas and ranks among the most important gas hubs in Continental Europe.

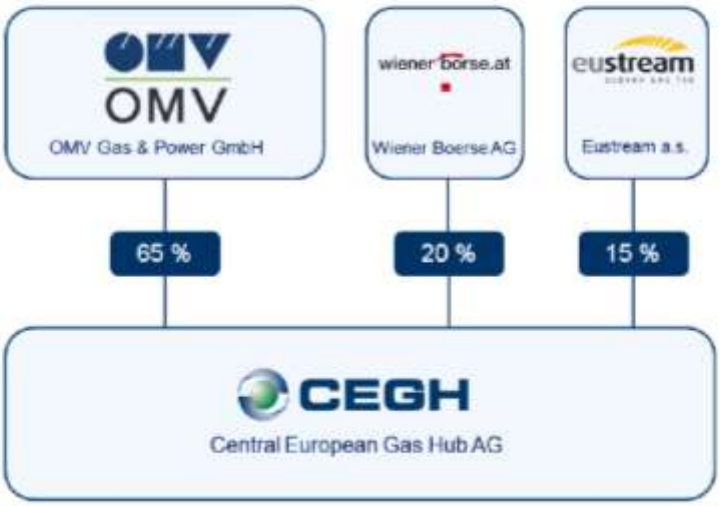
CEGH functions as a cross-regional balancing platform by offering trading activities and services for different markets, as shown in Figure 47.

Figure 47: OTC and Exchange Under One Umbrella at CEGH

Source: CEGH

Since 2016, the Austrian and the Czech CEGH Spot and Futures contracts have been listed on the pan-European PEGAS platform under the Powernext rulebook and exchange license. This gives international traders comfortable access to comprehensive trading, clearing and settlement services on multiple markets. Traded volumes in 2017 almost tripled – a clear indicator that the cooperation was more than just a step in the right direction. In 2018, volumes continued to grow and reached an all-time high of 133 TWh at the PEGAS CEGH Gas Market in Austria, an increase of 50% on an annual basis. It is worth noting that 218 companies were registered at CEGH by the end of 2018. This is a plus of 26 companies within one year. CEGH is based on a strong shareholder structure with OMV Gas & Power GmbH holding 65%, Wiener Börse AG holding 20% and Eustream a.s. holding 15% of shares (see Figure 48).

Figure 48: CEGH's Shareholder Structure



Source: CEGH

Through its connection to the important transit pipelines and storage systems, CEGH is the most attractive gas market in Central and Eastern Europe. The distribution station at Baumgarten is the most eastern distribution node in Europe. Plus, the direct connection of storage facilities to the CEGH VTP contributes to additional flexibility and makes gas trading in Austria even more attractive.

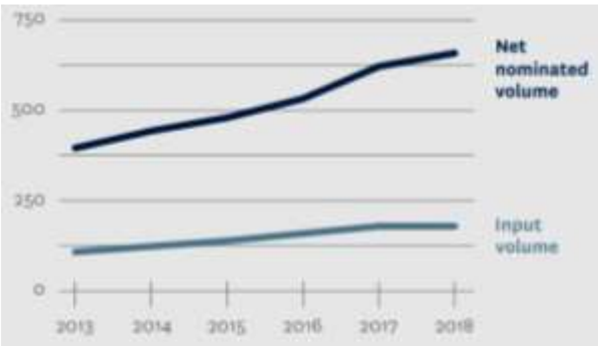
CEGH is the gas trading gateway between east and west and is the most attractive gas trading platform for SE European markets. Approximately one quarter of all Russian gas exports to Western Europe are handled via Baumgarten, Austria's most important gas turntable and Europe's most eastern distribution node. In the last years, more and more traders have also used CEGH as a trading place for transactions from west to east. This reflects the needs of Eastern European countries to import gas from the west. CEGH and its direct connection to important transit pipelines is a perfect intersection with connections in all directions towards Germany, Italy, Slovakia, Croatia, Slovenia, Hungary and further.

Table 13: Characteristics of CEGH Gas Exchange Products

	WITHIN-DAY MARKET (ONLY AT)	DAY AHEAD MARKET (AT AND CZ)	FUTURES MARKET (AT AND CZ)
Gas product	Base load	Base load	Base load
Delivery point	AT: CEGH VTP Austria	AT: CEGH VTP Austria CZ: Czech VTP	AT: CEGH VTP Austria CZ: Czech VTP
Settlement	Rest of day with a lead time of 3 hours based on the next full hour to 06:00 a.m. (d or d+1)	Physical delivery from 06:00 a.m. (d+1) to 06:00 a.m. (d+2)	Physical delivery from 06:00 a.m. (d+1) to 06:00 a.m. (d+2)
Trading hours	AT: 24/7	AT: 24/7 CZ: From 08:00 a.m. to 06:00 p.m.	AT/CZ: From 08:00 a.m. to 06:00 p.m.
Price units	€ per MWh, 3 decimal digits	€ per MWh, 3 decimal digits	€ per MWh, 3 decimal digits
Price change	€ 0.025 per MWh (min.)	€ 0.025 per MWh (min.)	€ 0.005 per MWh (min.) for orders in the order book
Trade size	1 MW (min.)	1 MW (min.)	1 MW (min.)
Single sided nomination	Done by ECC	Done by ECC	Done by ECC

Source: CEGH

Figure 49: CEGH VTP Austria: Volumes in TWh



Source: CEGH

Figure 50: PEGAS CEGH Austria and PEGAS CEGH Czech: Gas Market Volumes in TWh

Source: CEGH

3.1.13. Polish Power Exchange

https://www.tge.pl/en-home

Towarowa Giełda Energii SA (currently TGE) was established at the end of 1999. In the first six months, from registration of its business operations, it launched the Day Ahead Market (electricity spot market). In 2003, TGE was the first and so-far only entity to obtain a license to run a commodity exchange market from the Financial Supervision Commission (KNF).

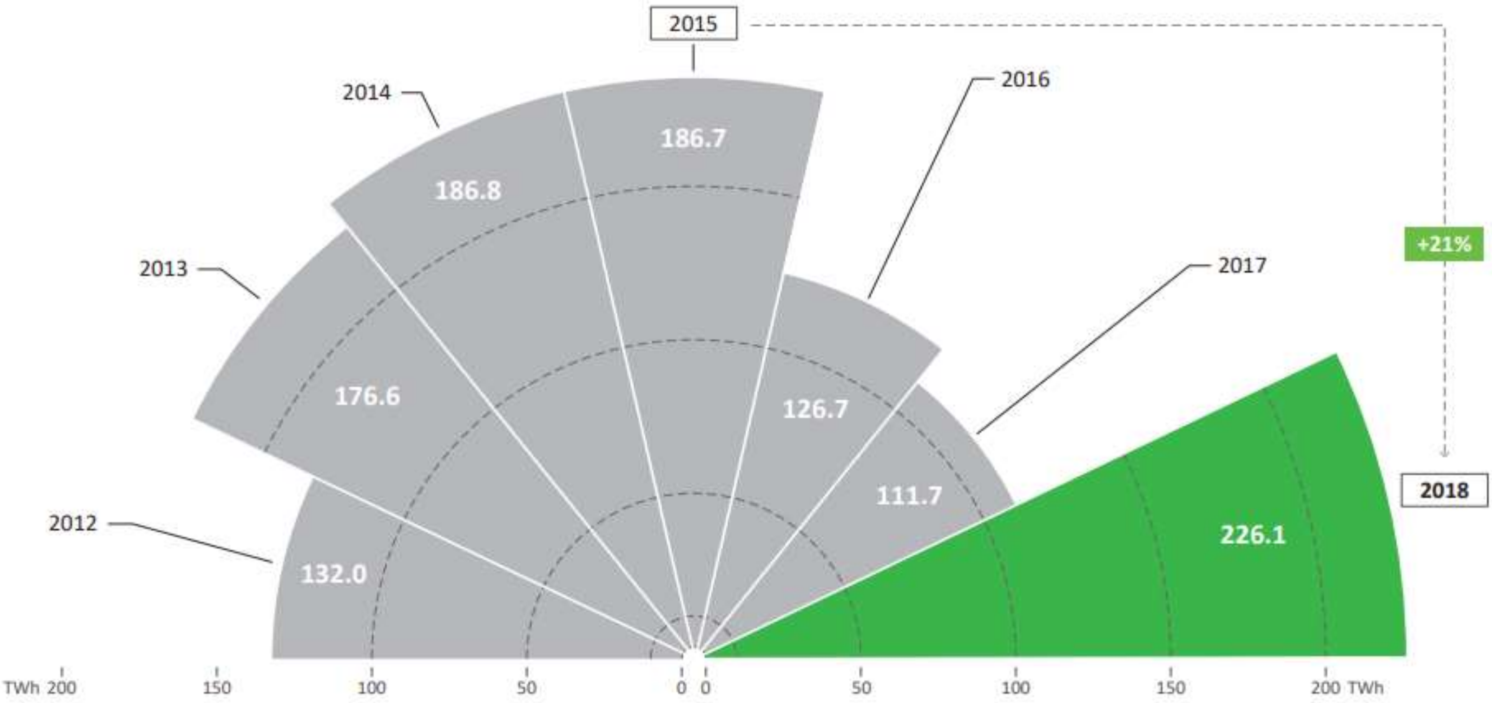
The key areas of TGE operations are:

- Day Ahead Market (DAM),
- Intraday Market (IDM),
- Day Ahead Market gas (DAMg),
- Commodity Forward Instruments Market with Physical Delivery (CFIM),
- Commodity Forward Instruments Market with Physical Delivery gas (CFIMg),
- Property Rights Market for Renewable Energy Sources and Co-generation, (PRM)
- CO_2 Emission Allowance Market (EAM).

In 2018, the trading volume on the exchange in Poland amounted to 145% of energy transmitted to the grid, which brings Poland closer to most developed EU countries and considerably exceeds the liquidity of markets in the region. The Polish Power Exchange has become a tried-and-tested partner on the European electricity market. Moreover, in the framework of their constant drive to create a fully competitive market, Polish legislators have decided that, in order to ensure equal conditions of access to its resources, the entire trading will take place on a regulated market in the coming years, which is presently represented in Poland only by TGE.

The Commodity Forward Instruments Market, on the other hand, had seen the volume of turnover compared to 2016 lowered by 12.7%, which in absolute numbers meant a decrease down to 86,410,400 MWh in 2017. The main reason for the decline was – as in the case of spot markets – the cut in the mandatory volume of electricity sold through the exchange, stipulated in Article 49a para. 2 of the Energy Law Act (i.e. concerning generators receiving support in connection with the termination of PPAs). Additional factor was the uncertainty of market participants related to the implementation of the MiFID II Directive into national law, which particularly affected business behaviour in the first half of the year and transformed into significant reductions of turnover on futures markets in other EU countries.

Figure 51: Total Electricity Volumes Traded on TGE in 2012-2018 (TWh)



Source: TGE

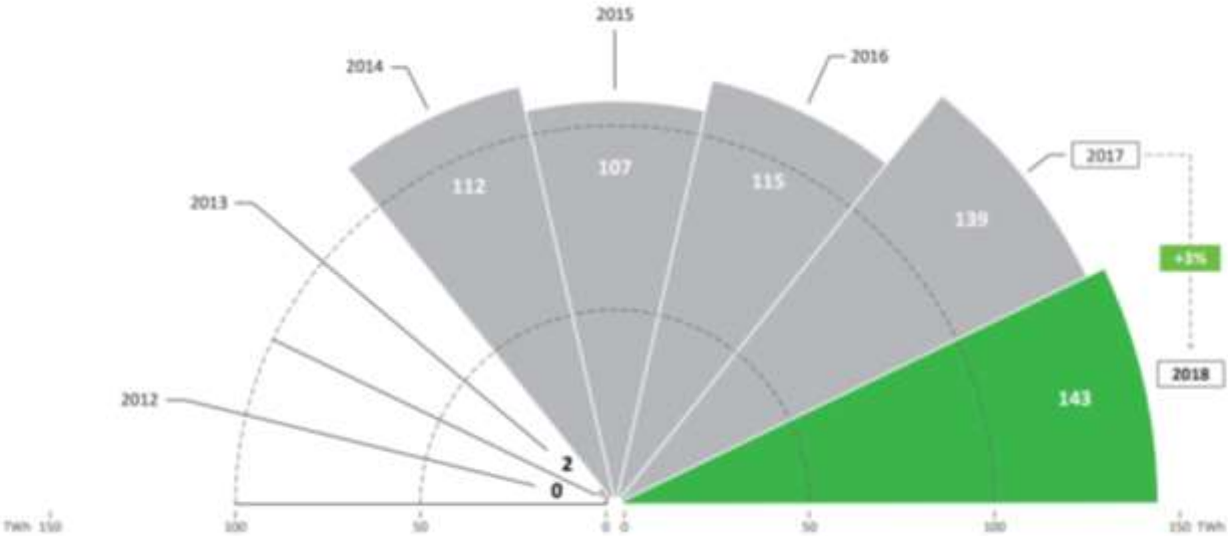
Figure 52: Average Monthly Electricity Prices on the Spot and Commodity Derivatives Market, including TGE, in 2018 (PLN/MWh)

Source: TGE

Natural Gas Market

The natural gas market on the Polish Power Exchange is young in comparison with the electricity market. TGE recorded minimum trading volumes in 2012-2013. Starting from 2014, the trading volume exceeded the domestic gas consumption volume by 50%. Similar to electricity, 2018 was a record year. The trading volume, amounting to 143 TWh, exceeded the so-far highest volume recorded in 2017 by 3%.

Figure 53: Total Volumes of Natural Gas Traded on TGE in 2012-2018 (TWh)



Source: TGE

In 2018, natural gas prices, similarly to electricity prices, increased; however, the pace of growth was less than half. In December 2018, the average monthly price of a contract with delivery in 2019 was 25% higher than in January.

Figure 54: Average Monthly Gas Prices on the Spot and Commodity Derivatives Market, including TGE, in 2018 (PLN/MWh)

Source: TGE

3.1.14. OTE (Czech Republic)

http://www.ote-cr.cz/

OTE, a.s., was founded on April 18, 2001 by the Czech Republic's government, which is the Company's sole shareholder. The Czech Ministry of Industry and Trade is authorized by the government to exercise the shareholders' rights. OTE's operations reaffirm the Company's irreplaceable position on the electricity and gas markets both in the Czech Republic and across Europe. OTE's core operations comprise:

- evaluation and financial settlement of imbalances between contracted and metered supply and consumption of electricity and gas;
- organization of the short-term electricity market and the short-term gas market and, in cooperation with the transmission system operator, organization of the balancing market with regulation energy;
- processing and exchange of data and information related to the electricity and gas markets through the Centre of Data Services, 24 hours a day, 7 days a week;
- administration of support for renewable energy sources;
- issuance of guarantees of origin of electricity from renewable energy sources and combined heat and power;
- performing the function of a national administrator of the Union registry for emission trading;
- provision of technical support for change of electricity and gas supplier in customer points of delivery;
- preparation of monthly and yearly reports on the electricity market and the gas market in the Czech Republic;
- preparation of reports on projected electricity and gas consumption and the method of ensuring balanced electricity and gas supply and demand;
- REMIT – Reporting of trade data.

In 2015, the services provided by the Market Operator were expanded to include reporting of trade data from OTE's short-term markets, set out in Regulation (EU) No. 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (REMIT). In connection with this obligation, the Market Operator has been registered by ACER as a Registered Reporting Mechanism (RRM). The certification is a necessary prerequisite for the provision of reporting services to market participants.

The organized block electricity market allows continual trading of fixed electricity blocks on specific trading days; this applies to standard blocks of the Base type (0:00–24:00), Peak type (8:00–20:00) and Off-peak type (0:00–8:00; 20:00–24:00). The volume of electricity traded on this market in 2018 totalled 17 GWh, as shown in Table 14. The organized day-ahead spot electricity market, operated since 2002, has been coupled through implicit auctions with the organized day-ahead electricity market in Slovakia since 2009, the day-ahead electricity market in Hungary since 2012, and the day-ahead electricity market in Romania since 2014. This type of trading is also known as Market Coupling. The volume of electricity traded on this market in 2018 totalled 22.89 TWh. In addition, the volume of electricity traded on the organized intraday market in 2018 totalled 550 GWh, while the volumes of positive and negative regulation energy traded on the balancing market totalled 25.2 GWh and 34.7 GWh in 2018, respectively.

Table 14: Volumes of Electricity and Gas Registered in the OTE System in 2018

electricity	sale	purchase
block market	17 GWh	17 GWh
day-ahead market	20,809 GWh	18,724 GWh
intraday market	550 GWh	550 GWh
bilateral transactions (internal nominations)	95,054 GWh	95,054 GWh
export/import	24,310 GWh	10,431 GWh

gas	sale	purchase
intraday market	3,059 GWh	3,059 GWh
bilateral transactions (internal nominations)	266.3 TWh	266.3 TWh
export/import	89.3 TWh	173.2 TWh
injection/withdrawal	32.3 TWh	32.6 TWh

Source: OTE

3.1.15. Power Exchange Central Europe (PXE)

www.pxe.cz

The POWER EXCHANGE CENTRAL EUROPE (PXE) is the Prague-based centre of competence for the Central and Eastern European power markets. As part of EEX Group, PXE is committed to further developing products and services for the Czech, Slovak, Polish, Hungarian and Romanian market. PXE was established on January 8, 2007 as Energetická burza Praha and, since then, offered services on the electricity markets, namely providing anonymous trading in and settlement of standardised power products.

PXE is part of the EEX group associating international energy and commodities markets with more than 550 trading participants from 36 countries worldwide. Energy products provided by PXE are traded on the platform of the EEX trading system, therefore, thanks to PXE, EEX trading participants have, apart from Western European markets, also access to trading in Czech, Slovak, Hungarian, Romanian and Polish power futures.

PXE also organises trading in gas in the form of derivative products delivered to a virtual trading point in the Czech market. The trading is realised in the PEGAS CEGH Czech Market of Powernext cooperated by PXE.

Trading in the above-mentioned derivative products is realised under the licence and within the trading system of EEX and Powernext; in fact, however, the relevant market segments in which these products are offered are administered and serviced by PXE. Thanks to this setting, all participants trading in the EEX and Powernext exchanges can trade PXE products without having to enter another exchange and unnecessarily incur related expenses. As compensation for using the licences of the above-mentioned exchanges, PXE distributes a portion of the revenues generated from trading in the products administered by PXE to these exchanges.

Since the migration of power futures to the EEX T7 platform on June 15, 2017, PXE witnessed a rapid increase in trading volumes primarily on the Hungarian, Slovak and Romanian markets. In 2018, a record volume of 53.41 TWh was traded on the Hungarian market, 14.85 TWh on the Romanian market, and 7.53 TWh on the Slovak market. Due to the lack of bilateral agreements between participants, the increase in volumes corresponds to an increase in the share of OTC registered trades.

On December 8, 2017, the migration of the CEGH Czech Gas Market to the PEGAS platform took place (the establishment of PEGAS CEGH Czech Market). In 2018, PXE saw the expected increase in liquidity, while a record volume of 3.48 TWh was traded in the spot market and 4.21 TWh in the futures market. All in all, 102.21 TWh of electricity and 7.69 TWh of gas were traded on PXE in 2018. In both cases, these are the best results achieved over the existence of PXE.

3.1.16. Hungarian Power Exchange (HUPX)

www.hupx.hu

As an important part of the energy market liberalization in Hungary, in 2010, MAVIR, the Hungarian TSO, has established its subsidiary, the Hungarian Power Exchange Company Limited by Shares. HUPX Ltd. is the operator of the organized Hungarian electricity market with leading position in Central and Eastern Europe. Through its regulation and adopted trading framework, it promotes the liquidity of the Hungarian energy market, and on regional level supports the flow of the working capital in the sector.

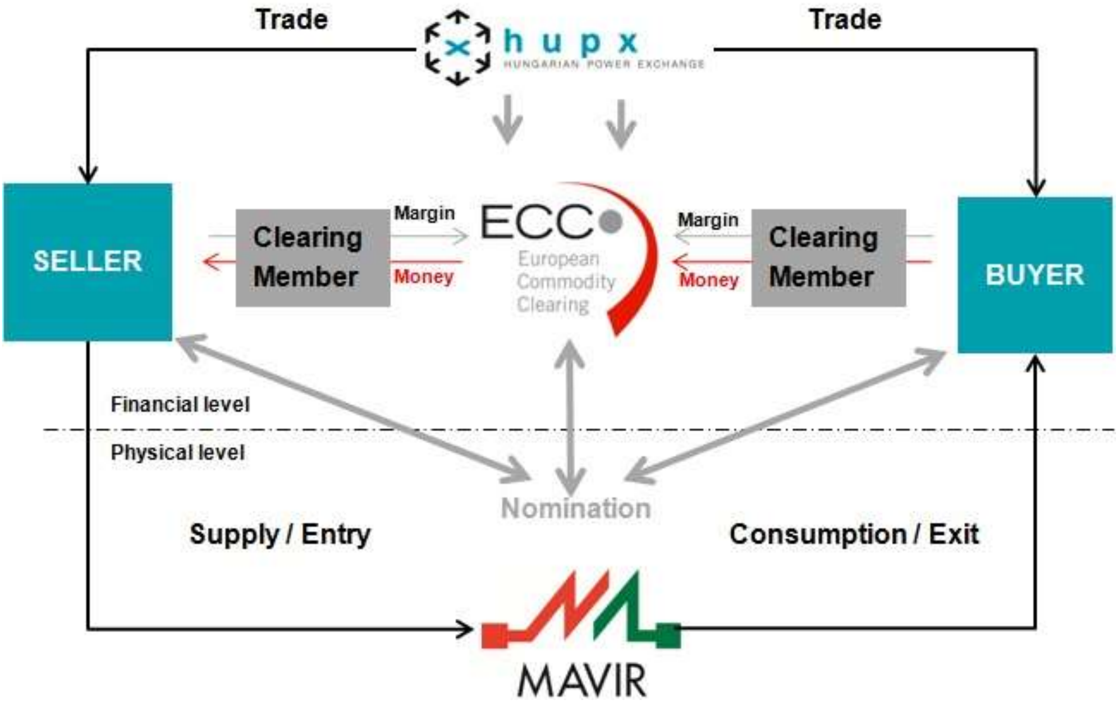
The core activity of HUPX – providing reference price and exchange trading platform - is effectively contributing to the development of the Hungarian electricity market. For the development of the market, it is important that the largest part of the electricity trading happens through the security system of the organized exchange. In order to do this, there is a need for adequate legal background, transparent conditions, unified access for all participants, and efficient use of resources, as well as value-for-money transaction costs and clear settlement prices as a reference price.

On HUPX DAM (day-ahead market), standard hourly and block day-ahead electricity products can be traded. The day-ahead market of HUPX is taking part in the 4-market coupling (4M MC[17]). Czech, Slovak, Hungarian and Romanian National Regulatory Authorities, Transmission System Operators and Organized Electricity Market Operators have established the PCR-based expansion of Czechoslovakian-Hungarian next-day

[17] 4M MC is a day-ahead implicit allocation method based on ATC (available transfer capacity) that seeks to maximize compatibility with the EU target model, while the 4M solution can be considered as an intermediate step in the Central-Eastern European and later "Core" regional solution.

electricity market with Romania on November 19, 2014. The total traded volume in 2018 reached 55.09 GWh, with total traded OTC volume at 14.41 GWh.

Figure 55: Trading and Clearing Procedure in HUPX



Source: HUPX

3.1.17. BSP Southpool

www.bsp-southpool.com

The company was founded in 2008 by Borzen, Power Market Operator, and Eurex Frankfurt, European Derivatives Exchange, AG. Since the change in ownership structure in 2010, shareholders of BSP have become Borzen, d.o.o and Elektro-Slovenija, d.o.o., both with the same 50% share. The company is entering the market under the trademark name BSP SouthPool.

The Slovenian **Day-ahead market** is conducted in a manner of auction trading in which market participants in the trading phase submit anonymous standardized hourly products on the EuroMarket trading platform. Products are limited by price range from 0 €/MWh to 3.000 €/MWh and with a quantitative interval of 1 MW.

The **Intraday market** is conducted in a manner of continuous trading in which market participants in the trading phase submit anonymous standardized and user-defined products in the ComTrader trading platform. Transactions are concluded on the basis of the price/time priority criterion.

3.1.18. Croatian Power Exchange (CROPEX)

https://www.cropex.hr/en/

Croatian Power Exchange Ltd. was established in May 2014 and is equally owned by the Croatian Energy Market Operator Ltd. and the Croatian Transmission System Operator Ltd.

CROPEX's mission is to provide a central place for electricity trading to market participants in a secure, reliable and transparent way. CROPEX operates the local Croatian day-ahead and intraday market and acts as a central counterparty for all day-ahead and intraday trades concluded on the trading platform.

Soon after going into operation in February 2016, CROPEX has been nominated as the Croatian NEMO. With the support of the local National Regulatory Authority, CROPEX, together with the Croatian TSO, entered into the Hungarian-Slovenian market coupling project with the final objective to be coupled with the wide EU MRC electricity market.

3.1.19. Independent Bulgarian Energy Exchange (IBEX)

http://www.ibex.bg/en

Independent Bulgarian Energy Exchange (IBEX) was established in January 2014, as a fully-owned subsidiary of the Bulgarian Energy Holding (BEH) EAD and holds a 10-year license from the Energy and Water Regulatory Commission to organise a Power Exchange in Bulgaria. IBEX works to establish and develop an organised electricity market in Bulgaria based on the principles of transparency and non-discrimination. The efforts of IBEX are aimed entirely at providing a reliable, transparent and competitive electricity trading platform to enable market participants to enter into transactions through a variety of organised market products:

- Day-ahead market (started 19 January 2016) as a serviced PX with trading platform provided by Nord Pool;
- Centralised market for long-term bilateral contracts (CMBC) (started 24 October 2016) - Auctions, continuous trading and hourly products, on a platform provided by Trayport;
- Intraday market (started 11 April 2018) as a serviced PX with trading platform provided by Nord Pool

In future, IBEX intends to expand its portfolio of products by adding to its market segments organised market for natural gas trading. IBEX is a full member of the MRC (Multi-Regional Coupling) project, as well as an associated member of the PCR (Price Coupling of Regions). IBEX EAD has been a member of Europex since January 2016.

As of 15 February 2018, the Bulgarian stock exchange AD is the sole owner of the shareholder's capital of Independent Bulgarian energy exchange (IBEX) EAD.

3.1.20. Short-term Electricity Market Operator (OKTE)

https://www.okte.sk/en

Short-term Electricity Market Operator (OKTE) in the Slovak Republic started its activities on January 1, 2011. OKTE was established as a subsidiary of the country's Transmission System Operator, which is the owner of 100% of shares. Within electricity market in the Slovak Republic, OKTE is classified by Energy Act as the entity that is subject to regulation by Regulatory Office for Network Industries (RONI), while it is authorized for activities as Short-term Electricity Market Operator.

OKTE shall treat all electricity market participants on the basis of open, transparent and non-discriminatory conditions when providing services. OKTE organizes and evaluates the organized short-term cross-border electricity market and provides clearing of imbalances in the Slovak Republic. Since November 22, 2011, OKTE is a member of EUROPEX.

3.1.21. SEEPEX a.d. Beograd (SEEPEX)

http://seepex-spot.rs/en/

The SEEPEX a.d. Beograd (SEEPEX) is a licensed Market Operator for an organized electricity market/power exchange established in the form of partnership between A.D. EMS and EPEX SPOT as a joint stock company. SEEPEX shall operate an organized electricity market, with the standardized electricity products and delivery within a time frame day-ahead and intra-day with the aim to offer these electricity products for trading in Serbia and in the SEE region, where appropriate.

SEEPEX organizes markets that are optional, anonymous and accessible to all companies satisfying admission requirements. The SEEPEX's objective is to ensure a transparent and reliable wholesale price formation mechanism on the power market by matching supply and demand at a fair and transparent price and ensure that all transactions concluded at SEEPEX are finally delivered and paid.

SEEPEX provides a marketplace where exchange members send their orders to buy or sell electricity in determined delivery areas. Its role consists in matching these orders in a transparent manner, according to the public market rules which among others describe the priorities and algorithms used for the matching of the orders.

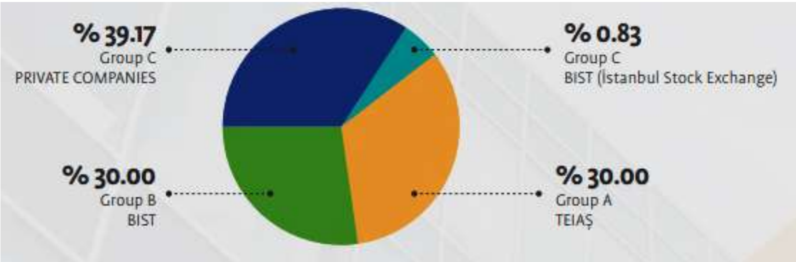
3.1.22. Turkish Energy Exchange (EXIST)

https://www.epias.com.tr/en/

Energy Exchange Istanbul (EXIST or EPIAS in Turkish) was officially established on March 12, 2015. Main objective and principal business activity is to plan, establish, develop and manage energy market within the market operation license in an effective, transparent, reliable manner that fulfills the requirements of energy market and to be an energy market management that procures reliable reference price without discriminating equivalent parties and maximizes the liquidity with increasing number of market participants, product range and trading volume as well as allowing to merchandise by means of market merger. EXIST became a member of the European Association of Energy Exchanges (EUROPEX) and World Association of Energy Exchanges (APEX) in 2016.

Currently, EXIST operates the spot electricity markets. By means of regulations established by Turkey's Ministry and Energy Market Regulatory Authority (EMRA) in 2017, all necessary operations have been completed with respect to the Natural Gas Permanent Trading Platform and the Natural Gas Organized Wholesale Market. There were totally 1,140 market participants registered with EXIST at the end of 2018. And, in 2018, while the cleared volume was 149,39 TWh in the Day-ahead Market and 2.93 TWh in the Intraday Market, the trading volume was TRY69.69 billion in the Day-ahead Market and TRY1.4 billion in the Intraday Market.

Figure 56: Shareholder Structure of EXIST



Source: EXIST

3.1.23. Hellenic Energy Exchange (HEnEx)

http://www.enexgroup.gr/en

HEnEx

Aiming to enhance competition, Greece has introduced numerous stages towards the liberalization and deregulation of wholesale electricity market. The formation of Hellenic Energy Exchange (HEnEx) is one basic reform that is in line with European regulation. Until the start of 2018, the electricity market in Greece operated through the public company LAGIE, which was responsible for undertaking the operation and monitoring he Day-Ahead market and Intra-day coupling. LAGIE's further responsibilities comprised clearing, settlement and reporting of transactions to both the Regulatory Authority for Energy (RAE) and the Agency for the Cooperation of Energy Regulators (ACER).

Aiming to modify this structure, Greek authorities in cooperation with the European Commission, have jointly formed a framework towards the implementation of Target Model guidelines. The Greek energy market framework was shaped radically in February 2017, when the Market Operator (LAGIE) and Athens Stock Exchange (ATHEX) signed a memorandum of cooperation, aiming to establish the Hellenic Energy Exchange that is designed to replace the current system of mandatory pool in June 2020.

The operation of the energy market is complemented by new provisions that will allow gas and environmental products to enter the platform. At the same time, the objective is to include renewables, which can facilitate to the forthcoming Power exchanges as suppliers.

Following the formation of HEnEx, a new entity was established as the Market Clearing House, in order to undertake the responsibilities of Clearing, Risk Management and Settlement of the transactions.

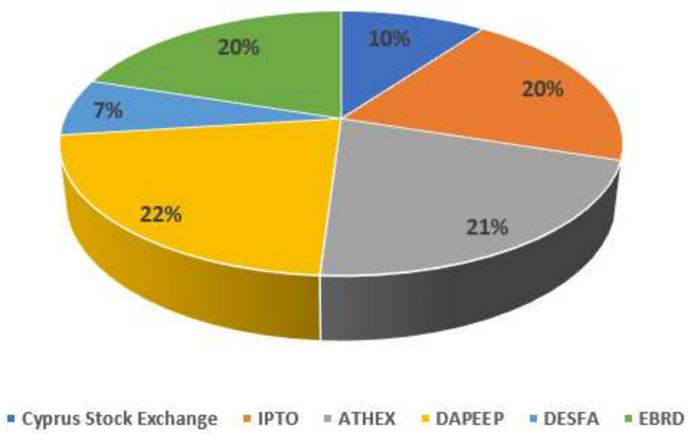
In line with the Third Energy Package, the transition to the new Target Model of the European wholesale energy market includes the formation of voluntary basis Power Exchanges, in parallel with the existence of Over-The-Counter (OTC) bilateral contracts. HEnEx operates in this exact way, by permitting participants to submit different orders for the supply of electricity for different production levels and time intervals and at the same time keeps a record of all OTC contracts.

Table 15: The Model for the HEnEx

	SPOT Markets			Derivative Markets	
Functions	Day Ahead	Intraday	Balancing	Physical Delivery	Cash Settlement
Trading	Energy Exchange	Energy Exchange	ADMIE	Energy Exchange	Energy Exchange
Clearing*	Energy Clear	Energy Clear	Energy Clear *	ATHEX Clear	ATHEX Clear
Settlement	Energy Clear	Energy Clear	Energy Clear *	ATHEX Clear	ATHEX Clear
Technical and Operational Support	ATHEX	ATHEX	ADMIE	ATHEX	ATHEX

Source: HEnEx

Figure 57: The Ownership Structure of the HEnEx



Source: HEnEx

3.2. The Role of Gas Exchanges in Promoting Gas Trade

There was a sharp increase in gas exchange trading post-financial crisis, especially in Anglo-Saxon countries from 2010 onwards, due to these markets being more financially secure than the OTC markets. Nevertheless, the gas exchanges are complementary to the OTC market and offer an alternative route to market for market participants, having very different modes of trading, different cash flow implications and of course, a different risk profile.

Being regulated markets, gas exchanges are obliged to make public the price and volume data which promotes price transparency and discovery and therefore, the ability to know the price of gas now for immediate delivery and in the future (up to six years ahead on ICE NBP and five years for ICE-Endex TTF). The data are publicly and easily accessible, either on the gas exchanges' own websites or disseminated through price reporting agency screens. Gas exchange trading allows for the ability to easily separate the price function from the physical supply function thereby providing a facility for managing price risk through a secure and regulated market, whilst keeping the physical flows separate.

As well as allowing for hedging and trading, the gas exchanges can also be a marketplace for the buying and selling of, usually, marginal quantities of physical gas and are in many countries the vehicle used for the balancing requirements of that hub. However, the main role and function of gas exchanges is that they are complementary to the OTC markets and assist in the development of gas trading hubs in a secure and regulated environment.

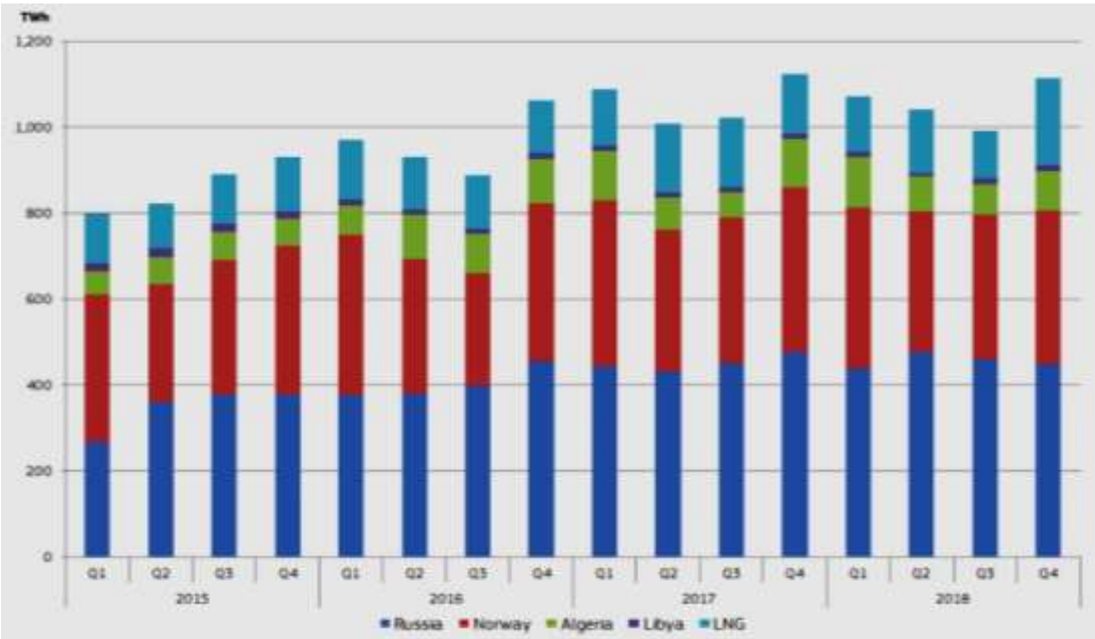
4. Potential Suppliers of European Gas Market and Their Role in Market Liquidity

According to the Quarterly Report on European Gas Markets, published by the European Commission, net imports of EU gas rose by 8% in the fourth quarter of 2018, compared to Q4 2017. Imports from Russia decreased by 6% y-y, while Norwegian imports also went down by 4%. Imports from Algeria decreased by 17%, while those from Libya rose by 10%. At the same time, LNG imports reached the highest over the last five years and ensured 18% of the total extra-EU gas imports. In Q4 2018, the total net EU gas import was 100 bcm, while in 2018, it amounted to 363 bcm, up by 3% (by 10 bcm), compared to 2017.

Russian pipeline supplies remained the main source of EU imports, covering 40% of extra-EU imports in Q4 2018, down by 2%, compared to the same period of 2017, and the lowest since Q1 2016. It was followed by Norwegian pipeline imports (32%), LNG imports (18%) and pipeline supplies from North Africa (10%). The EU's estimated gas import bill rose to around €28 billion in Q4 2018, 30% more than a year earlier. In 2018, the EU import gas bill is estimated to €90 billion, up from €75 billion in 2017, primarily owing to increasing import gas prices, compared to 2017, based on data provided by the European Commission.

EU LNG imports showed a huge increase in Q4 2018, up by 59% in y-y comparison. After a summer period with very low LNG send-outs, shrinking price premiums of the Asian LNG markets enabled more cargos to arrive in Europe in Q4 2018. Increasing LNG imports resulted in a shift of supply sources, as the share of Qatar and Nigeria in total extra-EU imports dropped from the previous quarter (to 22% and to 14%), while Russia became the second most important LNG source (17%) and the share of the US quadrupled, reaching 12% in Q4 2018.

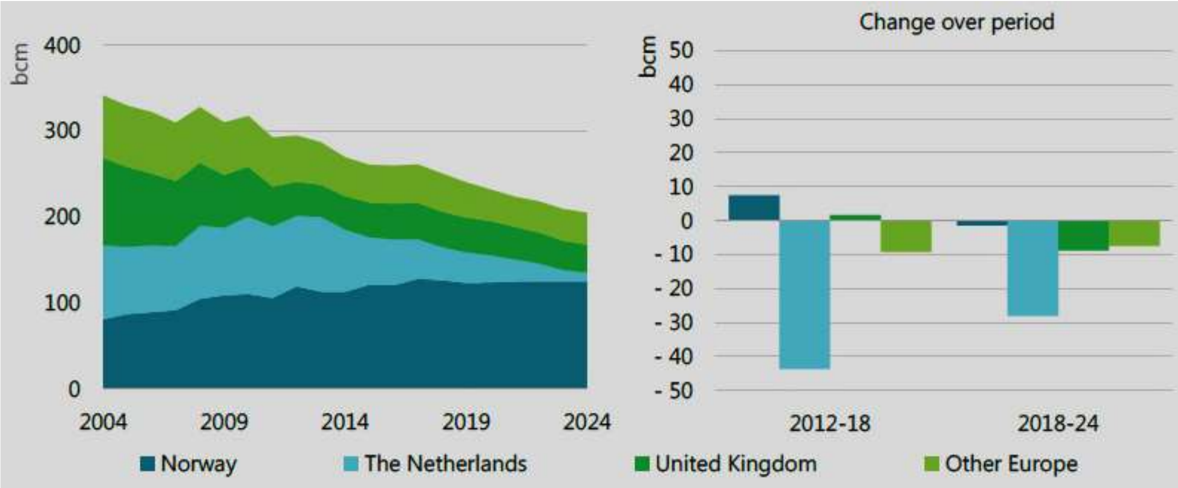
Figure 58: EU Natural Gas Imports by Country, 2015-2018



Source: European Commission, Quarterly Report on European Gas Markets (Vol. 11)

According to IEA's 2019 Gas Report **(15)**, gas production in Europe is expected to decrease at a rate of 3.5% per year by 2024, meaning that approximately 45 bcm of domestic gas supply will be lost. This is largely driven by the decision of the Dutch government to phase out the giant Groningen field by 2030 at the latest. As shown in Figure 59, the Netherlands accounts for over 60% of the decline in European gas supply by 2024.

Figure 59: Gas Production in Europe, 2004-2024



Source: IEA

Falling UK production is the second source of European production decline (18% of the region's decrease between 2018 and 2024). Production in other European countries, such as Denmark, Germany and Italy, is also expected to decline, and to be counterbalanced by production increases in Romania by 2024. Norwegian gas production, the largest contributor to European domestic supply, is expected to remain stable to 2024. Given that European gas demand is expected to remain stable over the next five years, declining domestic supply will further increase European gas import needs. Another consequence is the loss of some flexibility and timeliness associated with domestic production, which will foster the importance of other sources of supply flexibility such as gas storage, interconnectors and demand-side response.

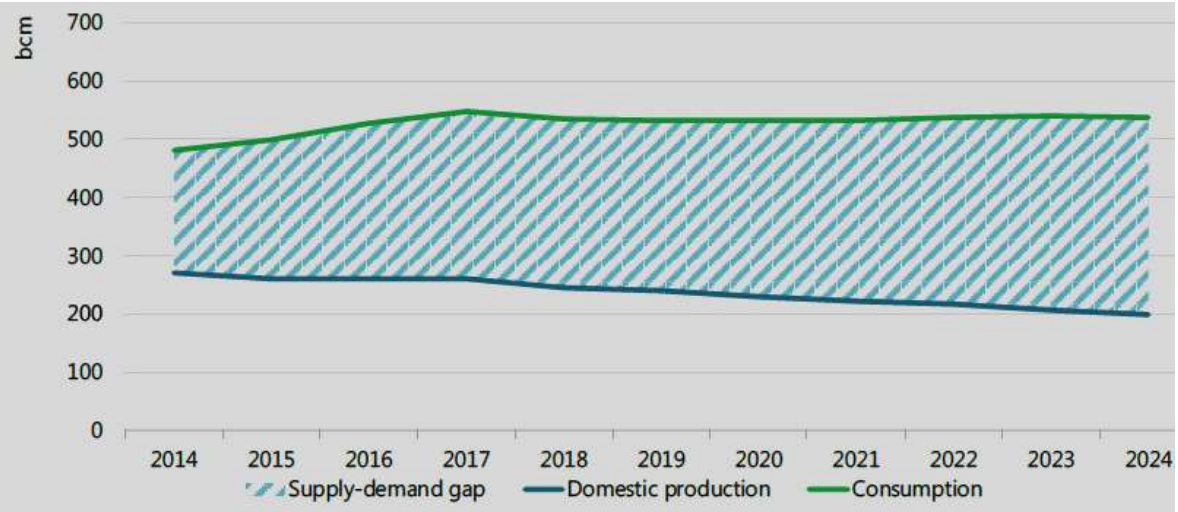
All in all, natural gas is a vital component of the EU energy mix and will undoubtedly continue to play an important role in EU's energy strategy. As already mentioned, energy security concerns have been expressed about possible curtailment in Russian gas supplies. The EU is currently looking to diversify supply and attract non-Russian gas in order to compensate for the EU production decline.

The internal European energy market is undergoing many changes, as the EU seeks to complete its integration and liberalization. The integration is expected to increase the energy market effectiveness, create a single European gas and electricity market, contribute in keeping prices at low levels, as well as increase security of supply. Trade between EU member states will become more flexible and thus, possible curtailments of Russian supplies will have less impact on the European gas market.

A Widening Supply-Demand Gap

As IEA points out, European gas import requirements are expected to increase by almost 50 bcm/y by 2024 to reach 336 bcm/y (see Figure 60). Whilst European gas consumption is set to remain almost flat, domestic production is set to fall at an average rate of 3.5% per year, primarily driven by the Groningen phase-out in the Netherlands and declining production in the North Sea.

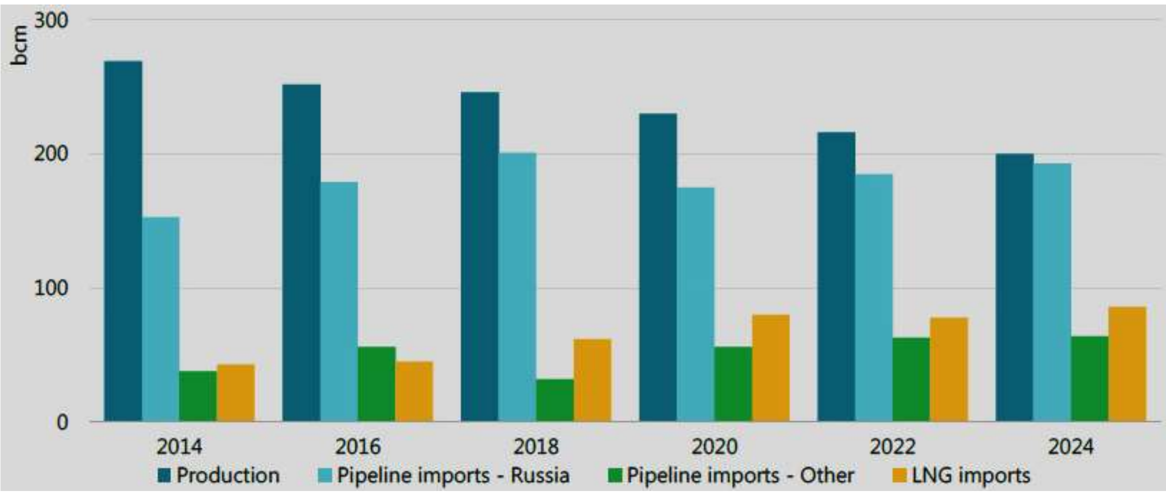
Figure 60: Gas Supply-Demand Gap in Europe, 2014-2024



Source: IEA

Incremental import requirements will be met by a variety of supply sources, including new pipeline gas imported through the Southern Gas Corridor, additional LNG volumes from an increasingly flexible global gas market and from traditional suppliers such as Russia (see Figure 61). Because of this diversification, the market share of Russian pipeline gas is expected to decline from its 2018 record high of 37% to a range of 33-36% by 2024.

Figure 61: Gas Balance in Europe, 2014-2024

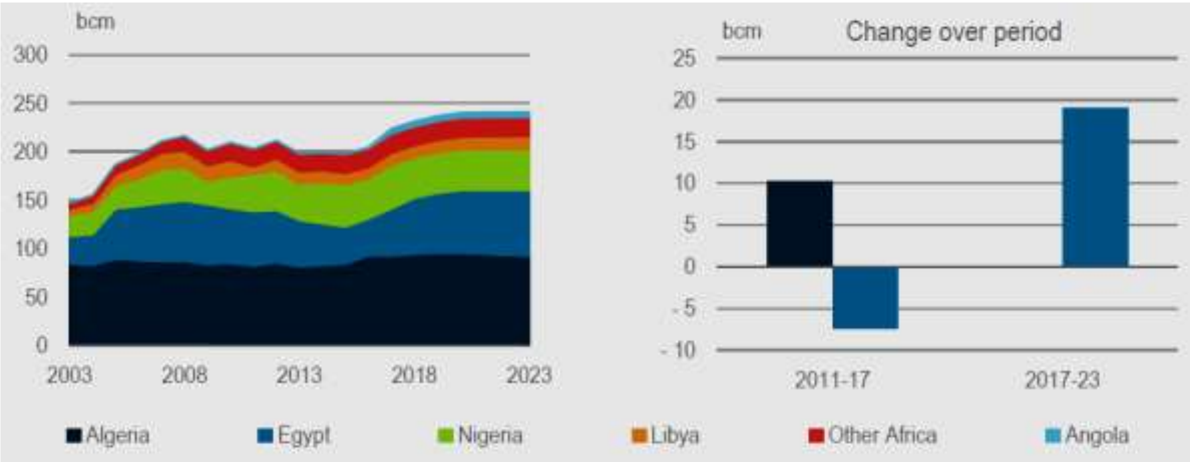


Source: IEA

4.1. North Africa

The Middle East and North Africa (MENA) are the two regions which together account for more than 40% of the world's proven gas reserves. North Africa remains the continent's leading region for natural gas production and it has been a traditional gas supplier to Europe. Proved gas reserves in the African continent are concentrated in four countries: Nigeria, Algeria, Egypt and Libya. These four countries account for roughly 92% of the continent's total. While Algeria has dominated gas exports for decades, Libya and Egypt's gas export sectors have developed rapidly, although both have faced serious obstacles in recent years. However, the current economic and political uncertainties in North African countries, such as Egypt, Libya, Algeria and Tunisia, are likely to affect investments in upstream and downstream markets.

Figure 62: African Gas Supply by Country, 2003-2023



Source: IEA (16)

Table 16: Key North African Natural Gas Data in 2018 (bcm)

	Reserves	Production
Algeria	4.300	92,3
Egypt	2.100	58,6
Libya	1.400	9,8
Nigeria	5.300	49,2
Other Africa	1.200	26,7
Total	**14.300**	**236,6**

Source: BP Statistical Review of World Energy 2019 (17)

4.1.1. Algeria

Algeria is the third-largest supplier of natural gas to the European Union, after Russia and Norway. According to the 2019 BP Statistical Review, Algeria's proven natural gas reserves corresponded to 4,3 tcm in 2018. At current production levels, this would provide output approximately for another 60 years.

According to IEA's 2019 Gas Report, Algerian gas production is expected to stagnate and even slightly decrease by 2024 in spite of new production start-ups in 2019, due to the continuous decline of historical production. The country's marketed gas output remained stable over the recent past and even increased in 2016, but this was achieved thanks to a drastic reduction in gas reinjection – which accounted for most gross gas use until 2011. This shift was driven by the imperative of meeting the structural rise in domestic needs without impacting gas exports, which are a key source of revenues for Algeria's economy.

This drop-in reinjection is understood to have caused some damage to reservoir integrity and led to lower pressure and recovery in the Hassi R'Mel complex, the main historical contributor to Algeria's gas production. It accounted for up to 75% of the country's total gas production in the early 2000s. State-owned operator Sonatrach announced investment to prevent further decline, which is due to be completed in 2020.

New production assets have recently started production as part of the 9 bcm/y Southwest Gas project to counterbalance this decline: the Reggane and Timimoun fields both delivered their first gas in 2018, and the project's third and largest element, the 4.5 bcm/y Touat field, was expected to start deliveries by mid-2019.

However, the outlook remains uncertain in the absence of further announced developments to limit production decline over the medium term. This lack of production growth, combined with the expected continuous increase in domestic demand, has led to some concerns over Algeria's export capacity, as voiced in December 2018 by the then-Energy Minister Mustapha Guitouni, who highlighted the risk of seeing gas exports ending by 2032. Algeria has been preparing changes to its hydrocarbon law to attract greater foreign investment. These were expected during the first half of 2019, having been announced by the CEO of Sonatrach in late 2018. However, his dismissal in late April 2019 adds further uncertainty to the timing of oil and gas reform, IEA adds.

Map 13: Algeria's Gas Exporting Pipelines

Sources: Sonatrach, OIES

4.1.2. Egypt

According to IEA's 2019 Gas Report, Egypt's gas production rose to around 58 bcm in 2018, based on early estimates. According to Petroleum Minister Tarek El-Molla, the country achieved self-sufficiency by the end of September 2018, owing to the completion of new stages to increase gas production from four major fields in the Mediterranean Sea: Zohr, Nooros, Atoll and the first and second phases of the West Nile Delta complex.

The Zohr field became in 2018 the main asset in Egypt's gas production rebound, with production of about 10 bcm/y after commissioning in December 2017, on a par with the Nooros field which started operation in 2016 and reached its expected plateau level in 2018. According to Eni, which jointly operates Zohr with the state-owned Egyptian General Petroleum Corporation (EGPC), the field is set to reach production of around 28 bcm/y.

Several other fields were recently developed under BP-led operations: Atoll (close to Zohr's Shorouk offshore block), which delivered its first gas in February 2018, and the Giza and Fayoum fields in the second phase of the West Nile Delta (WND) complex in February 2019. With the expected start-up of the Raven field in late 2019, the three phases of WND are expected to deliver up to almost 15 bcm/y, equivalent to about one-quarter of Egypt's current gas production. All the gas produced will be fed into the national gas grid.

According to the Ministry of Petroleum, Egyptian gas production should reach the equivalent of almost 80 bcm/y in fiscal year 2019/2020. Based on current projects under development, this forecast does not share the ministry's optimistic outlook. It nevertheless expects strong growth until 2023 with a plateau of 77 bcm/y – or an average annual growth rate of 4.8% by 2024. However, Eni's discovery at Nour in March 2019 (under evaluation at the time of writing) may lead to further developments in the offshore Egyptian Mediterranean. In parallel, the government launched a bid round in March 2019 for ten blocks in the less-explored offshore Red Sea, according to IEA.

4.1.3. Libya

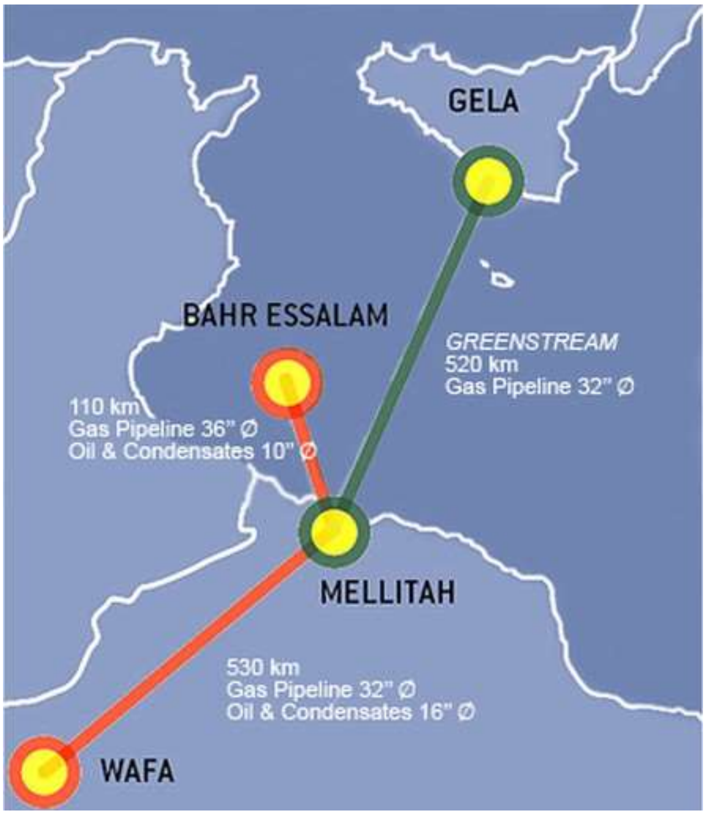
Libya's natural gas industry recovered in 2012, but production still remains below the pre-war level. Libya's rank as a producer and reserve holder is less significant for natural gas than it is for oil. About half of its natural gas production is exported to Italy via the Greenstream pipeline **(18)**, as shown in Map 14. BP estimates that Libya's proved gas reserves were 1.4 tcm in 2018, making it the fourth largest natural gas reserve holder in Africa (see Table 16). Before the transformative events of 2011 civil war, new discoveries and investments in natural gas exploration had been expected to raise Libya's proved reserves in the near term.

Libya's natural gas sector is mostly state-run by the National Oil Corporation (NOC) and its Sirte Oil Company subsidiary. IOCs in Libya are less involved in natural gas production than they are in oil production, although Italian oil and gas company Eni is a notable exception because of its stake in the large Western Libya Gas Project (WLGP). Italy is currently the sole recipient of Libya's natural gas exports. The WLGP, which is operated by Eni and the NOC through the Mellitah Oil & Gas joint venture, accounted for most of Libya's natural gas production growth after 2003. The WLGP includes the onshore Wafa field and offshore Bahr

Essalam field. Typically, most of the natural gas produced from WLGP is exported via the Greenstream pipeline, and the remainder is consumed domestically.

In 1971, Libya became the third country in the world (after Algeria in 1964 and the United States in 1969) to export LNG. Libya's sole LNG plant, built in the late 1960s at Marsa al-Brega, is owned by the NOC and operated by Sirte Oil Company. However, the plant went offline in February 2011 as a result of damage sustained during the civil war and has not exported LNG since early 2011. A joint venture between Libya's NOC and Italy’s Eni announced in July 2018 that natural gas production started at the second phase of the Bahr Essalam project off the coast of Libya.

Map 14: Greenstream Pipeline



Source: NOC

4.2. Russia

According to IEA’s 2019 Gas Report, Russian gas production has risen strongly over the last three years, at an average annual growth rate of 4.4% (totalling almost 90 bcm/y of additional supply) from 638 bcm in 2015 to 725 bcm in 2018 – its highest level in 18 years. This has been driven by growing domestic consumption (up 5.3% in 2018) and by increasing exports (up 8.5% in 2018), both via pipelines and via LNG. The three trains of Yamal LNG, each 7.48 bcm/y, were commissioned during 2017 and 2018. A fourth, smaller train (1.22 bcm/y) is expected to be commissioned by the end of this year, bringing total Russian liquefaction capacity up to 37 bcm/y.

Table 17: Selection of Russian Gas Production Projects

Plant	Project Leader	Status	Plateau	Plateau Capacity
Bovanenskoye	Gazprom	Producing	2020	115 bcm/y
Rospan	Rosneft	Producing	2019	19 bcm/y
Kharampur	Rosneft	Under development	2020 - commissioning	11 bcm/y
Sibnetfegaz fields	Rosneft	Under development	2022	16 bcm/y
North-Russkoye	Novatek	Site preparation	2022/2023	14 bcm/y
Kharasaveyskoye field	Gazprom	Under development	2023	32 bcm/y
Chayandinskoye	Gazprom	Under Development	2024	25 bcm/y
Kovyktinskoye	Gazprom	Under development	2025	25 bcm/y

Sources: Compilation based on information from companies' reports and investors' presentations

4.3. LNG Imports

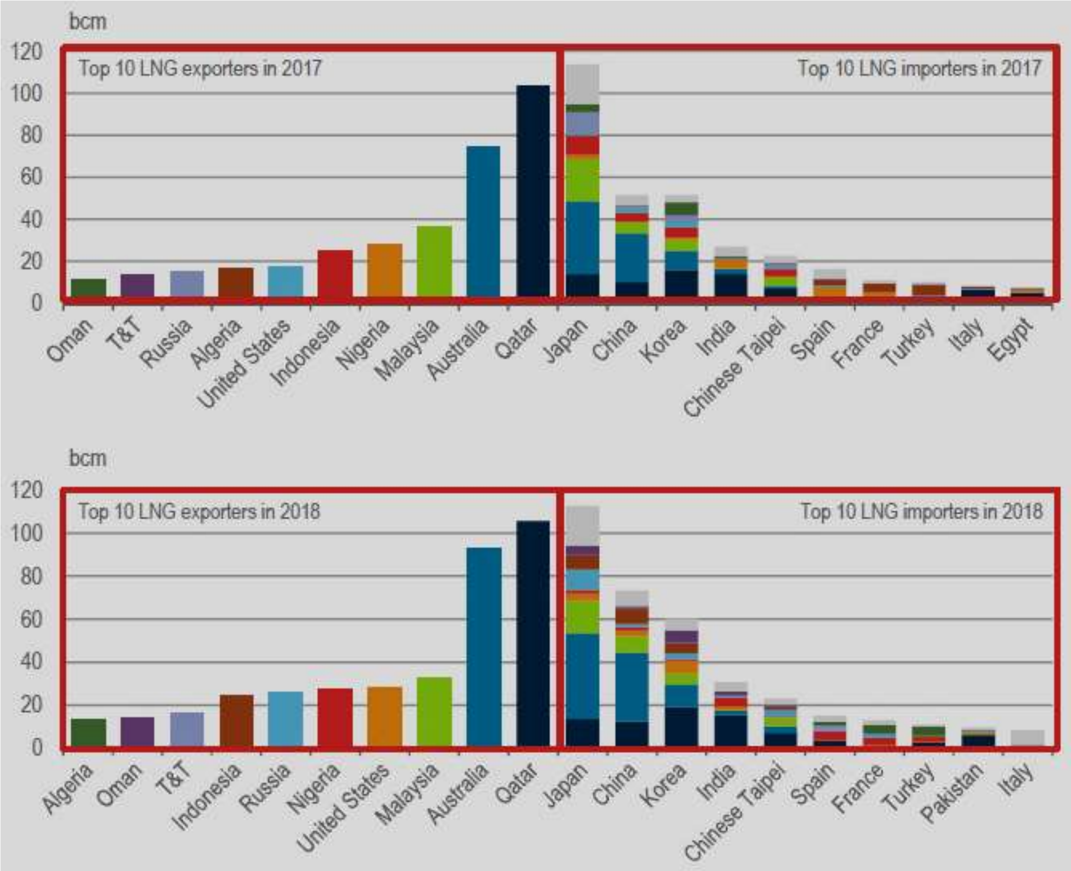
Natural gas markets are transitioning from local to regional and global markets, with increasing competition and diversity among suppliers and customers. LNG is the driving force to further enhance competition and market integration in international natural gas markets. Its development is favoured by the state of the well-supplied market that is assumed to continue over the coming five years. The expansion in supply capacity (nearly 200 bcm) will exceed expected LNG demand growth (forecast to be closer to 100 bcm by 2022), according to IEA's "Gas Market Liberalisation Reform" Report. **(19)**

The global LNG market is expanding, supported by investment decisions taken during the previous decade. The United States and China are influencing LNG market dynamics due to their size and impressive growth potential. Both 2017 and 2018 were remarkable in this respect as China is now the second-largest LNG importer, after Japan. The United States is increasing in importance on the supply side and is becoming a major source of LNG, Becoming the fourth largest LNG exporter in 2018 after Qatar, Australia and Malaysia (see Figure 63).

China's rise as a major LNG importer will strengthen Asia's dominance on the demand side. But increasing LNG exports from the United States will diversify the supply landscape, increasing global gas supply security through a greater variety of LNG exporters.

Asian LNG demand has been particularly driven by Japan and Korea, which have a lack of alternative gas import options. The shutdown of nuclear power plants supported gas-fired power generation, increasing gas consumption well above business-as-usual levels with significant rippling effects on LNG spot prices, trade flows and contractual long-term obligations to purchase LNG have affected both countries. China's rise in natural gas importation is backed by policies to improve air quality in large cities. Natural gas will therefore play a role in enabling China to reduce its share of coal in heat and power generation, mainly for the industrial and residential sectors, the IEA adds.

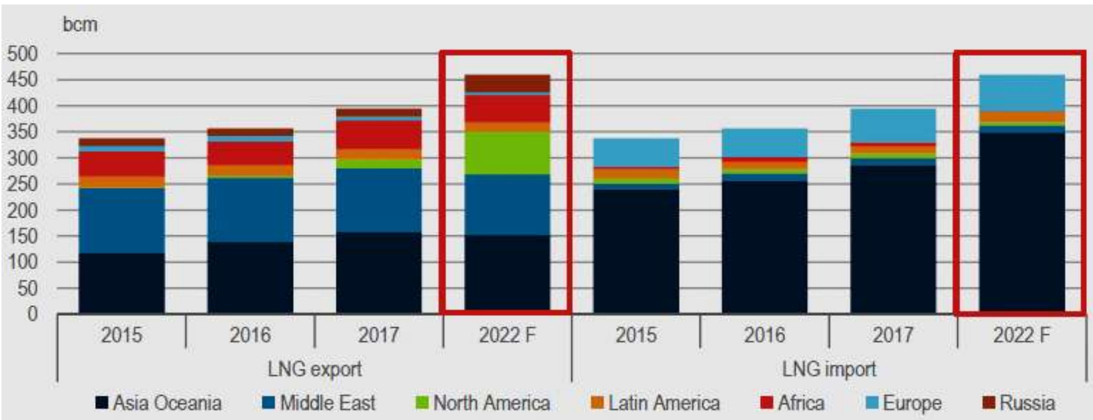
Figure 63: Selected LNG Exporters and Importers in 2017 and 2018



Source: IEA

Signs of diversification on the supply side are already visible. The top five exporters will be from four different regions (Middle East, Asia and Pacific, Africa and North America) by 2022 because of the rapid increase of liquefaction capacity in the United States. Liquefaction projects under construction along the US Gulf Coast and US East Coast will connect the global LNG market to US shale gas and influence global market dynamics. US LNG exports are expected to reach levels just above 80 bcm by 2022, supported by competitive production costs and impressive growth (see Figure 64).

Figure 64: LNG Supply and Demand, 2015-17 and 2022 (forecast)

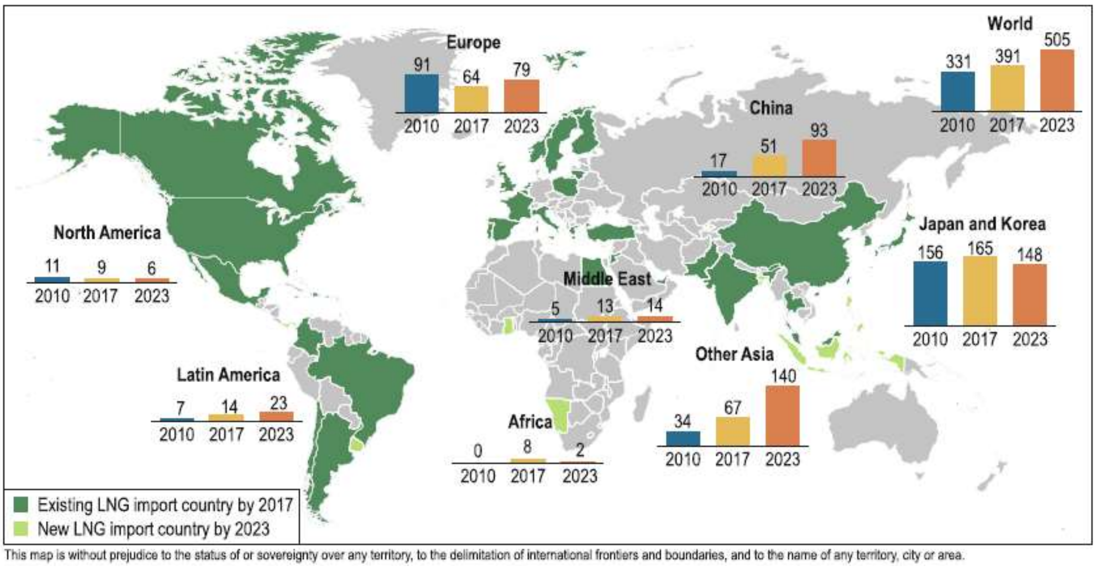


Source: IEA

In Europe, there are multiple supply options, making the estimation of European LNG supply and demand more difficult. The major suppliers of LNG in Europe are Qatar, Norway, Algeria, Nigeria and Egypt. Pipeline - imported natural gas from Russia, Norway and North Africa, as well as natural gas imported from planned pipelines, could weaken LNG demand in Europe. LNG demand growth can also be weakened by gas-on-gas competition, which is constantly gaining ground, and the global and regional economic uncertainties. Unconventional natural gas supply sources, such as shale gas, coalbed methane and tight gas, could provide an alternative source of natural gas supply for Europe.

Europe's gas imports are dominated by pipeline infrastructure, despite Finland, Lithuania, Malta, Poland and Sweden recently becoming LNG importers in Europe. Europe's current LNG import contracts are expiring: if most of these contracts are not renewed, LNG import volumes to Europe will decrease by around 17 bcm by 2022, compared to 2010.

Map 15: LNG Import Countries and Volumes (in bcm), 2010-2023



Source: IEA

Total net imports to EU-28 countries remained similar to levels we saw in 2017. In 2018, EU-28 countries imported 401 bcm of natural gas, just 0.6% more than in 2017. LNG became an integral part of the natural gas source mix, growing by nearly 19% over the last two years. In 2018, almost 50 bcm of gas was withdrawn from LNG storage and entered the European pipeline system, compared to 47.4 bcm and 41.9 bcm in 2017 and 2016, respectively. This has been driven by an attractive LNG price spread between Europe compared to Asia, which encouraged global LNG suppliers to divert cargoes to Europe, according to IEA.

Russia and Norway remained the key natural gas suppliers to the European Union, with a 39% (+1% y-y) and 27% (-1% y-y) share of supply, respectively. Combined, they provided almost 2/3 of natural gas supplied to EU countries. Germany (78.9 bcm or 19.7%), Italy (63.8 bcm or 15.9%), and France (47.8 bcm or 11.9%) were the main importers of natural gas. Combined, these three countries made up almost half of total gas imports to Europe.

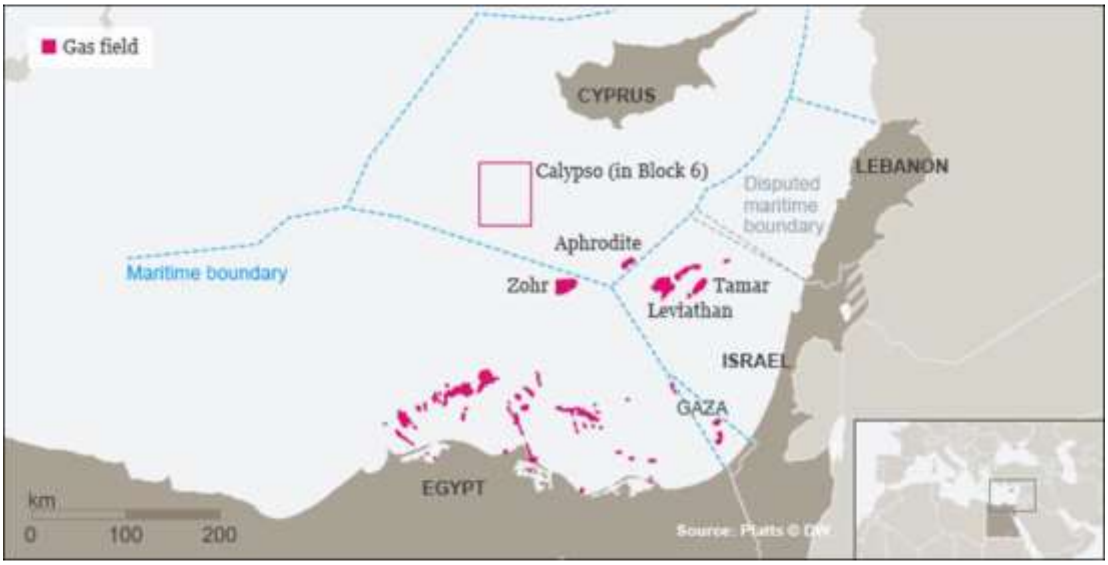
4.4. Eastern Mediterranean Region

The past few months have been busy for the Eastern Mediterranean gas sector. After nearly a decade of speculation about the potential of the region's resources, recent developments seem finally to have set it in the right direction.

In January 2019, energy ministers from Cyprus, Egypt, Greece, Jordan and Israel, with representatives from Italy and the Palestinian Authority, met in Cairo to discuss regional co-operation in offshore gas. The result was the Eastern Mediterranean Gas Forum (EMGF), a platform aimed at developing a regional natural gas market and taking advantage of existing LNG infrastructure in Egypt. It followed an agreement in December 2018 between Egypt and Cyprus, who committed to creating and maintaining conditions for the construction of a pipeline connecting the Aphrodite gas field in offshore Cyprus to Egypt's LNG facilities.

There was another development on February 28, 2019, when ExxonMobil announced a new gas discovery in offshore Cyprus, more than doubling the country's estimated offshore resources. Those involved should now put aside any differences among them and grasp the opportunity at hand. The region's gas saga started in 2009-2011, with the discovery of the Tamar and Leviathan fields off the shore of Israel, and the Aphrodite field off the shore of Cyprus. Various export options were progressively put on the table, from pipelines (to Turkey or Greece) to LNG plants (in Cyprus, Israel and Egypt). Expectations were great and the discoveries were promoted as a means to foster a new era of economic and political stability in the region.

Map 16: The Major Gas Fields in the Eastern Mediterranean Region



Sources: Platts and DW

However, initial expectations have since been damped. In Israel, a long debate on the management of gas resources caused uncertainty and delays in investment decisions. In Cyprus — where gas was welcomed as a godsend to relieve the country's financial troubles — enthusiasm was cooled by successive downward revisions in the size of the discoveries. These developments raised scepticism over the whole idea that the region might become an exporter of natural gas.

However, hopes were revived in 2015 when the Italian energy company Eni discovered the Zohr gas field off the shore of Egypt, the largest gas discovery ever made in the Mediterranean. In an unprecedented fast-track development, production at Zohr began in December 2017, helping Egypt recover its self-sufficiency in gas after turbulent years in which the country turned from a net exporter to a net importer. Zohr also marked a new phase of exploration in Egypt's offshore waters, leading to further discoveries. The significance of Zohr goes well beyond Egypt. Its proximity with other fields off Israel and Cyprus could allow for coordinated development and, thus, provide the economies of scale required to create competitive regional gas-export infrastructure.

Egypt already has LNG export infrastructure in Idku and Damietta with a capacity of 19 bcm a year — but it currently sits idle. This could enable prompt export of gas from Egyptian, Israeli and Cypriot fields. Both plants could be expanded if need be. For Israel and Cyprus, cooperating with Egypt is crucial. Building export infrastructure and developing fields is a circular problem. If there are political or commercial risks that no export infrastructure will be in place when production starts, a lot of money will be lost. If the field underperforms compared with expectations, expensive infrastructure will sit idle. (For example, the proposed Cypriot LNG Vasilikos project has an estimated cost of €5 billion; similarly, the East Med pipeline project connecting Israel, Cyprus, Greece and Italy is estimated to cost more than €6 billion). Bringing together underused and scalable export infrastructure with several promising fields could be the key to unlocking untapped regional potential.

The most logical course is to create an Eastern Mediterranean gas market based on the existing LNG infrastructure in Egypt, with benefits for all the regional players involved. This would also present an opportunity for Europe, where gas-import requirements are likely to grow in the coming years as domestic production declines, and where a large capacity to receive LNG already exists.

Such an approach would also offer Eastern Mediterranean suppliers flexibility in terms of destination markets in the future, allowing them to serve Asian markets, for example, through Egypt's LNG terminals. Finally, a joint regional export scheme, through the Egyptian LNG facilities, could also provide a first opportunity to test commercial gas cooperation between Egypt, Israel and Cyprus. If successful, this cooperation could eventually scale up in the 2020s, should new discoveries be made in the region and should gas demand in Europe justify the construction of pipeline infrastructure.

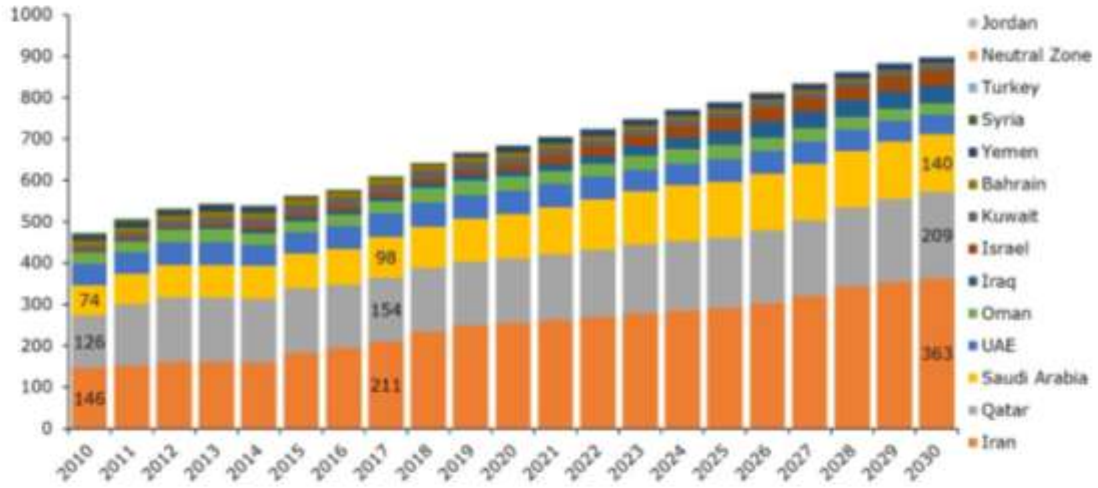
4.5. Middle East

According to the BP Statistical Review 2019 **(20)**, Middle East gas production increased by 5.7% over 2017-2018; from 650.4 bcm to 687.3 bcm. The region, however, is not homogenous. Iran and Qatar have the largest reserves in the region whereas other countries in the Middle East have insignificant gas reserves.

With the exception of Qatar, exports via pipeline and LNG are minimal, and the rapid growth in indigenous gas demand means that any increase in production is easily absorbed within the region. Discovered resources total 35.8 tcm or 28% of the world's total, but to what extent the region will be able to take advantage of this going forward is far from certain.

While Middle Eastern gas output has thus far failed to reach the potential offered by its massive reserves, production figures from the region have in fact shown steady growth in recent years – in spite of multiple hurdles in the form of sanctions, wars and general turbulence. Back in 2010, the marketed natural gas output in the region amounted to 472 bcm, but by 2017 it had crept up to 609 bcm. Based on several forecasts, Middle East gas production will increase to 898 bcm by 2030, which will predominantly be driven by the three largest gas producers – Iran, Qatar and Saudi Arabia. **(21)**

Figure 65: Middle East Gas Production (bcm), 2010-2030



***Source: Rystad*[18]**

Although sanctions were imposed on Iran up until 2016, the country has been the main driver of regional gas growth. Between 2010 and 2017, Iran added 65 bcm to its annual production, which comprised nearly half of the region's total increase during this period. And, unlike the country's oil production, the steady growth in gas production is not expected to be hampered by US President Trump's decision to withdraw from the Joint Comprehensive Plan of Action (JCPOA). Given that nearly all gas fields in Iran are owned and operated by national companies and the gas is mostly consumed domestically, the reinstated sanctions will have a limited effect on total gas production. However, one exception is Total's South Pars (Phase 11) project. Total has delayed the development of the field pending a sanctions waiver. If the company is not granted an exemption from the sanctions, it has stated that it will pull out of the project and sell its share to the co-owner, China National Petroleum Corporation (CNPC). The startup of the field is therefore expected to be delayed until 2024. Overall, Iranian gas production is forecasted to reach 363 bcm in 2030, Rystad adds.

In addition, Qatar and Saudi Arabia are expected to grow their collective gas production from 200 bcm in 2010 to 349 bcm in 2030, with 60% of this coming from Qatar. While the combined increase in gas production from these two countries is far below the forecasted Iranian growth, it is still a significant contribution to the overall tally for the Middle East.

[18] Rystad (2018), "Can The Middle East Realize Its Enormous Gas Market Potential?", https://www.rystadenergy.com/newsevents/news/press-releases/Can-the-Middle-East-realize-its-enormous-gas-market-potential/

Most of the initial growth will come from Saudi Arabia, with the startup of the Hasbah and the Haradh-Hawiyah fields, but in the longer term we see growth ramping up in Qatar as well. This is mainly owing to the removal of the moratorium on the North Field in 2017, which allows for expansions of both the Barzan and Qatargas projects among others.

Gas output in the UAE and Oman is forecasted to remain relatively stable at around 55 bcm and 30 bcm per year, respectively, between 2010 and 2025. However, from the mid-2020s both countries face decreasing gas production as new discoveries and developments are unable to offset the countries' mature field decline.

Iran is the fourth largest consumer of natural gas in the world after the US, Russia and China. From 2010 to 2017, demand in the country grew at an average annual rate of 4.6%, reaching a total of beyond 200 bcm in 2017. The strong growth was fueled by a rapid expansion of the domestic natural gas distribution network, and growth in the power, residential, industrial and petrochemical sectors. Despite a slowdown due to lower economic performance at the start of the decade, the increase in demand accelerated again after 2014, driven by gas-for-power consumption that reached an all-time high of 66 bcm in 2017.

The Iranian economy was forecasted to grow at a rate of 4% for the next couple of years, but this could now be closer to 2% due to the reinstatement of economic sanctions (the economy grew at an average yearly rate of 2% between 2005 and 2015 when the previous set of sanctions was in place). Despite an anticipated slowdown in the economy, gas demand is expected to continue growing in line with production and reach a level of 340 bcm by 2030. The country has invested heavily in the petrochemical sector and has widely promoted the use of compressed natural gas vehicles that will contribute to further growth in gas demand. The government is also trying to increase the share of gas in the power mix to reduce its dependency on more expensive liquid fuels.

Saudi Arabia will see a similar situation to Iran, whereby demand will be driven by the increase in domestic production. Gas demand in the kingdom has grown at the same rate as production, leaving no spare volumes for exports. And the lack of import infrastructure (both pipeline and regasification terminals) means that Saudi Arabia cannot increase its gas consumption further even if there is a need. Demand grew 32% between 2010 and 2017, driven by consumption from the petrochemical and power sectors. Total consumption in 2017 was 91 bcm (excluding losses and the industry's own use), in line with production. Nevertheless, the use of crude oil to generate power to cover peak demand during summer months, which is more expensive and generates more emissions, is evidence that gas supplies have not been able to keep up with demand, according to Rystad.

There are no concrete plans to build gas import infrastructure in Saudi Arabia, meaning that demand will be capped by domestic production going forward, reaching a level of 130 bcm by 2030 (an increase of 43% from 2017). However, earlier in 2018, Russian gas producer Novatek expressed an interest in building a regasification terminal in Saudi Arabia that could help boost supplies. Although the government has not communicated a clear development strategy for natural gas, it is expected that the growth in demand will be driven by the power sector, with estimates that 25 GW of gas-fired power generation could be added in the near term. Gas-fired power generation will play a crucial role in backing up the planned deployment of renewable energy, with an aim to generate 9.5 GW from renewable sources by 2030.

The United Arab Emirates (UAE) is another country that has not been able to realize gas production to its full potential. The country has the second largest gas consumption per capita in the world and needs to import around one third of its supply in order to meet the demand of 75 bcm per year. However, demand is forecasted to drop to around 70 bcm towards 2030 as the country looks to diversify its energy consumption away from gas.

Despite the region's vast efforts to deploy more renewable power capacity, led by Saudi Arabia, it is unlikely that this will have a major effect on gas demand between now and 2030. Given the region's continued high consumption of liquid fuels, any additions in solar, wind or even nuclear power capacity should be directed towards reducing liquid fuel rather than gas consumption.

In contrast to its neighbors, Qatar has the potential to increase production further and regain the crown as the largest LNG exporter in the world, which Australia is set to take later this year. The emirate, with a population of less than 3 million people, has the world's third largest discovered gas reserves, with an estimated 12.7 tcm, and produces more than 140 bcm per year. As a result, even with a forecasted increase in demand of around 3% per year during the next few years, the country has sufficient resources to meet its own demand and continue being one of the main suppliers of LNG in the world, Rystad notes.

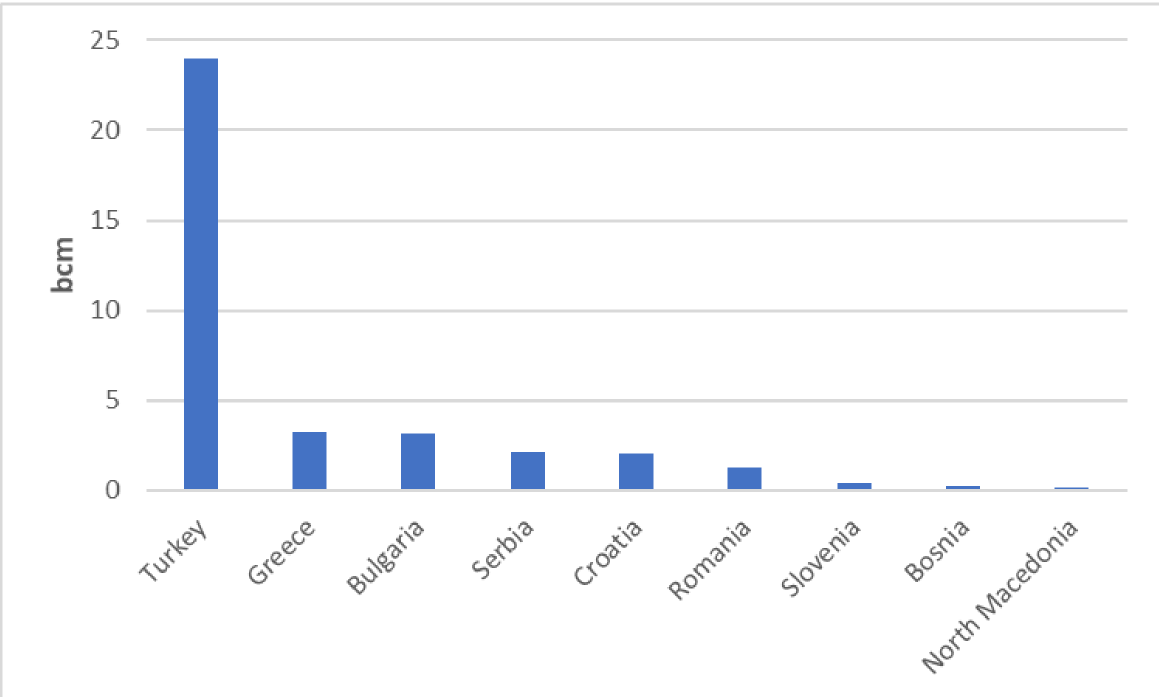
5. SE Europe as a Gas Transit Region

5.1. The Rising SE European Gas Market

Europe sees an important opportunity to meet its energy needs by developing the Southern Gas Corridor, at the core of which are gas supplies from the Caspian area (including Azerbaijan and most likely in the far future from Turkmenistan, Kazakhstan and Iran) and possibly from the Middle East (i.e. Iraq). According to the current state of play in SE Europe, forecasts predict that the demand will grow up to 2025 at a rate of 1% each year.

Six of the SE European countries (i.e. Greece, Croatia, Bulgaria, Romania, Turkey and Serbia) already use natural gas, having well established markets, with supplies coming primarily through imports from Russia (see Figure 66) and, in the case of Turkey, from Iran and Azerbaijan also. Greece and Turkey, which have well developed LNG import and storage terminals, also import from Algeria, Nigeria, Qatar and other LNG spot markets. Two countries have a significant proportion of their demand met from domestic supplies (i.e. Croatia, Romania) and three others cover small percentage shares from domestic gas (i.e. Bulgaria, Serbia, Turkey). In projecting future demand for gas in the region, one of the main issues is the extent to which availability of gas would make possible the displacement of other fuels in various categories of demand, such as power generation and residential, commercial and industrial applications. Relative prices and competing fuels lie at the heart of analysis, although potential growth in demand for gas will also be driven by other factors, including environmental aspects and national policies.

Figure 66: Russia's Gas Supplies to Selected SEE Countries (bcm), 2018



Source: Gazprom Export (22)

It is generally assumed that the natural gas sector will grow faster in the SE European region mainly because the main driver for gas consumption growth is power generation which is emerging as one of the faster developing sectors of the broader SE European energy market. While each single SEE gas market is relatively small, a regional approach provides a sound basis for development. Romania is the biggest gas producer of the region with 9.5 bcm annual production (2018), while the consumption of the SE region (excluding Turkey) is around 22.7 bcm (2018). The three most gas dependent countries of the SE European region are Turkey, Bulgaria and Greece. Indigenous gas production in SE Europe (excluding Turkey), at 12.9 bcm/year, is sufficient to cover around half of current gas demand. However, not all countries in the region are gas consumers. This is especially true in Western Balkans which in the vast majority of their geographical expanse do not have any gas infrastructure.

5.2. Gas Flows in SE Europe

Currently, gas is mainly delivered under long-term contracts at prices linked to oil prices, while minimal gas volumes are traded at market prices. Minimal gas-to-gas competition and infrastructure adjustments emerged in the SE European region during and after the January 2009 gas supply crisis. Several new gas pipeline options have been proposed for the region over a period of more than 30 years. These include projects of massive volume and scale (e.g. South Stream and Turkish Stream), extraordinary scope and financing requirements (e.g. NABUCCO, Cyprus-Greece, White Stream, LNG Croatia, etc.) or moderate dimensions (e.g. TANAP, TAP, ITGI, etc.) as well as an almost indefinite number of gas interconnections some of which have been harmonized as the Western Balkans Gas Ring. Almost all such proposals intend to supply gas demand outside of this region – mostly in the rest of Europe. However, only a small fraction of these projects is being realized as is shown in Map 18, which depicts the Expanded South Corridor concept.

Gas Demand and Supply

According to a study **(23)** prepared by the Oxford Institute for Energy Studies as well as IENE's "SE Europe Energy Outlook 2016/2017" study **(24)**, SE Europe is not a homogenous region in terms of gas market maturity, infrastructures and gas interconnections. Greece, Croatia, Bulgaria, Romania, Serbia and Turkey have well-established gas markets, with supplies coming primarily through imports from Russia and, in the case of Turkey, from Iran and Azerbaijan. Greece and Turkey, which have well developed LNG import and storage terminals, also import from Algeria, Nigeria, Qatar and other LNG spot markets. Greece also imports gas from Turkey gas system, in the form of "Turkish gas basket". Two countries have a significant proportion of their demand met from domestic supplies (Croatia, Romania) and three others cover small percentage shares from domestic gas (Bulgaria, Serbia, Turkey). On the other hand, some other countries of the region completely lack gas infrastructure such as Albania, Kosovo, Montenegro and Cyprus.

(a) Greece

Gas Demand and Supply

Gas was originally introduced into the country's fuel mix in the fourth quarter of 1996 and has to compete against lignite and fuel oil in its primary applications. Greece's natural gas production was 0.1 bcm in 2018, which is negligibly small compared to the total consumption of 4.9 bcm, based on data provided by BBSPA Statistical Review 2019 **(25)**. The country is thus dependent on gas imports, mainly from Russia, Algeria (supplying LNG imports) and Turkey.

Natural gas consumption increased rapidly from insignificant levels in 1997 to a peak of 4.9 bcm in 2018. Power generation is the largest gas-consuming sector, accounting for half of the total gas consumption in 2018. This share has fallen from levels of around 70% a decade earlier. The decline in natural gas consumption is mainly due to reduced gas power generation, which fell by over half from a peak at 13.9 TWh in 2011 to 6.8 TWh in 2014, but increased to 9.1 TWh in 2015, representing 18% of the total power generation. The fall in total electricity generation (12% from 2011 to 2015) and the growth in renewable energy sources (81% from 2011 to 2015), which have replaced natural gas in the power mix, have resulted in a reduction in gas power generation.

Table 18: Natural Gas Demand and Supply in Greece, 2018

bcm	Gas
Production	0.1
Net Imports	4.8
Consumption	4.9

Sources: IEA and IENE

Greece's Gas Outlook

Table 19 summarizes the gas consumption projections in Greece for the period 2019-2028, based on DESFA's basic scenario.

Table 19: Gas Consumption Projections (in mil. Nm^3/yr) for the Period 2019-2028 (Basic Scenario)

	Electricity generation	Gas consumers connected to the grid	Gas distribution networks	CNG volumes	Reverse flow and North Macedonia	Small-scale gas	Total
2018	2.814	569	891	0	10	0	4.284
2019	2.551	675	940	0	10	0	4.176
2020	2.703	677	968	1	50	2	4.401
2021	2.448	658	989	1	100	6	4.201
2022	2.531	675	1.013	2	500	25	4.745
2023	2.754	675	1.029	3	550	55	5.066
2024	2.903	659	1.050	5	600	86	5.303
2025	3.229	675	1.061	7	620	106	5.698
2026	3.427	675	1.077	9	650	126	5.963
2027	3.555	657	1.092	10	650	146	6.110
2028	3.548	677	1.112	12	650	166	6.166

Sources: IENE and DESFA[19]

[19] DESFA (2018), "Development Study 2019-2028", http://www.desfa.gr/userfiles/5fd9503d-e7c5-4ed8-9993-a84700d05071/Development%20Study%202019-2028_ENG.pdf

(b) Bulgaria

Gas Demand and Supply

In Bulgaria, natural gas consumption stood at 3.04 bcm in 2018, decreased by 5%, compared to the previous year. Since 2010 and up to 2015, final energy consumption in Bulgaria increased due to higher industrial and transport needs. Only 4% of the natural gas is consumed by households.

Bulgaria has been producing natural gas from its continental shelf in the Black Sea since 2001. The increase of local production in 2011 and 2012 follows the development of new fields in Kaliakra and Kavarna. A small part (8%) of the inland consumption of natural gas is covered from local sources. The country relies mostly on natural gas imports to meet its domestic demand. Bulgaria's gas production stood at 0.01 bcm in 2018, recording a fall of 98.2%, compared to 2011 level.

Russia is the sole gas exporter to the country. Bulgaria also acts as a transit route for Russian gas destined for Turkey, Greece and North Macedonia. Bulgaria's gas imports decreased slightly during 2017-2018; from 3.13 bcm in 2017 to 3.028 bcm in 2018. The gas imports are based on long term "take-or-pay" contracts between Bulgargaz (Bulgaria) and RAO Gazprom (Russia).

Table 20: Natural Gas Demand and Supply in Bulgaria, 2018

bcm	Gas
Production	0.01
Imports	3.03
Consumption	3.04

Sources: Eurostat and BBSPA

Bulgaria's Gas Outlook

Bulgaria's gas consumption was 3.04 bcm in 2018 and is expected to rise rapidly over the next 10 years. Bulgartransgaz EAD, Bulgaria's TSO, estimates that natural gas demand in the country in 2019 will be 3.5 bcm and will gradually increase to 4.6 bcm/year by 2028, on the basis of sustainable economic growth of GDP - between 2 and 3% annually[20]. Natural gas imports in the country, exclusively from Russia, currently cover 97% of the domestic demand but Bulgartransgaz, in its Ten-Year Network Development Plan, anticipates that the significant increase in natural gas demand over the following years, will be met by alternative routes and sources of supply.

(c) Croatia

Gas Demand and Supply

In Croatia, gas production stood at 1.28 bcm in 2018, recording a constant fall from 2015 onwards (2015: 1.83 bcm). Natural gas is produced from 16 onshore and 9 offshore gas

[20] Bulgartransgaz (2019), "2019-2028 Ten-Year Network Development Plan of Bulgartransgaz EAD", https://www.bulgartransgaz.bg/files/useruploads/files/amd/tyndp%202017/TYNDP%202019-2028%20EN.pdf

fields. In 2018, gas consumption reached 2.84 bcm, while Croatia's gas imports stood at 1.56 bcm, coming from various countries. Until very recently, Croatia elected to buy on open spot market and did not renew its long-term contract from Gazprom when it expired in 2011. However, in 2017, a new ten-year contract was signed with Gazprom for 1 bcm/y. Gas demand in Croatia is dominated by the residential sector (1.4 bcm), followed by the industrial, fertiliser and petrochemical industry (close to 1.1 bcm) with the remaining covered by the power sector (0.4 bcm).

Table 21: Natural Gas Demand and Supply in Croatia, 2018

bcm	Gas
Production	1.28
Imports	1.56
Consumption	2.84

Sources: Eurostat and BBSPA

Croatia's Gas Outlook

In Croatia, gas consumption is expected to increase by about 5.6% over 2018-2027; from 2.84 bcm in 2018 to about 3.0 bcm in 2027, according to the Ten-Year Development Plan of Croatia's gas TSO Plinacro. This will lead to an increasing gas import requirement over the decade. The power sector has increased its reliance on natural gas as a fuel for generation, with this trend expected to continue over the coming decade. There has also been a steady increase in the use of liquefied petroleum gas as a fuel for the transport sector.

(d) Romania

Gas Demand and Supply

In Romania, gas consumption is almost equally divided between the domestic and industrial sectors; in the latter, gas is used primarily in the production of electricity and as raw material in petrochemicals. In 2018, Romania's gas consumption stood at 11.9 bcm, while its gas production reached 10.3 bcm. Almost all of the gas quantities imported in Romania (i.e. 1.6 bcm in 2018) are delivered via pipeline, as there are no LNG import facilities. The vast majority of the gas pipeline imports originate from Russia and its imports recently increased; from 1.19 bcm in 2017 to 1.32 bcm in 2018.

Table 22: Natural Gas Demand and Supply in Romania, 2018

bcm	Gas
Production	10.3
Imports	1.6
Consumption	11.9

Sources: Eurostat and BBSPA

Romania's Gas Outlook

In 2018, Romania's gas consumption was 11.9 bcm, of which 96.4% was accounted for domestic production and 2.8% for imports (0.6 bcm)[21]. In line with ENTSO-G estimates, demand is estimated to remain relatively stable over the following years and could reach 12.2 bcm by 2020[22].

(e) Serbia

Gas Demand and Supply

Natural gas consumption in Serbia is largely based on imports from Russia and partially from domestic gas fields, located in the province of Vojvodina (Petroleum Industry of Serbia - NIS). Gas consumption stood at 2.93 bcm in 2018, recording a 2% decline, compared to 2017 level. Natural gas exploration and production in Serbia is performed solely by NIS, with its gas production reaching 0.45 bcm in 2018, a 13% increase, compared with 2017 level.

Table 23: Natural Gas Demand and Supply in Serbia, 2018

bcm	Gas
Production	0.45
Imports	2.48
Consumption	2.93

Sources: IENE and BBSPA

Serbia's Gas Outlook

Currently, natural gas demand in Serbia is approx. 3.0 bcm/year and is estimated to reach 2.6 bcm/year by 2030, based on the Reference Scenario used by Serbia's 2016 Energy Sector Development Strategy Report[23].

(f) Turkey

Gas Demand and Supply

In Turkey, gas consumption amounted to 49.64 bcm in 2018, recording a 7% fall, compared to 2017 level. Gas production reached 0.51 bcm in 2018, almost doubled in comparison with 2017 level.

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[21] Romania's Regulatory Authority for Energy (ANRE) (2018), "National Report 2017", https://www.anre.ro/en/about-anre/annual-reports-archive

[22] ENTSO-G (2018), "Ten-Year Development Plan (TYNDP), 2018-2027", https://www.entsog.eu/tyndp

[23] Serbia's Ministry of Mining and Energy (2016), "Energy Sector Development Strategy of the Republic of Serbia for the period by 2025 with projections by 2030", http://www.mre.gov.rs/doc/efikasnost-izvori/23.06.02016%20ENERGY%20SECTOR%20DEVELOPMENT%20STRATEGY%20OF%20THE%20REPUBLIC%20OF%20SERBIA.pdf

Table 24: Natural Gas Demand and Supply in Turkey, 2018

bcm	Gas
Production	0.51
Imports	49.13
Consumption	49.64

Sources: IENE and BBSPA

Turkey's Gas Outlook

Projections concerning natural gas demand growth in Turkey vary significantly, with estimates for 2030 ranging from 60 to 70 bcm/year[24].

(f) North Macedonia

Gas Demand and Supply

In 2018, North Macedonia's gas consumption was 0.18 bcm, very close to 2016 levels, and natural gas is fully imported from Russia through the only entry point at the Bulgarian border, as there are no gas production or gas exploration activities in the country. The distribution network in the city of Strumica, in the South of the country, is not connected with the transmission network and supply is ensured by truck transport of compressed natural gas (CNG) from Bulgaria. North Macedonia does not have any gas storage facilities.

Table 25: Natural Gas Demand and Supply in North Macedonia, 2018

bcm	Gas
Production	0.00
Imports	0.18
Consumption	0.18

Sources: IENE and BBSPA

North Macedonia's Gas Outlook

In line with North Macedonian Energy Resources (NMER)'s estimations, the gas consumption in North Macedonia is estimated to elevate to 0.6 by 2025 and up to 1 bcm until 2040.

(g) Ukraine

Gas Demand and Supply

Ukraine has enough gas reserves (i.e. the second largest in Europe after Norway) to materially substitute import and aims to increase domestic production from 20 to 28 bcm by 2020. This ambitious target requires a set of regulatory and fiscal enablers to be in place at the national level. Over the last years, Ukraine completely switched to natural gas imports from European direction; moreover, it has reduced imports by 50% between 2013-

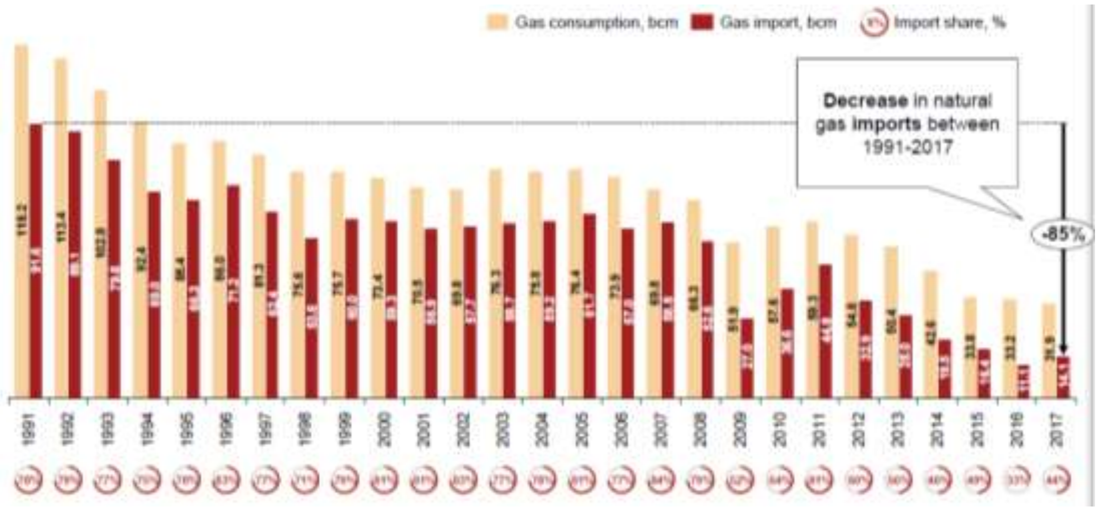
[24] Rzayeva, G. (2017), "Turkey's gas demand decline: reasons and consequences", *Oxford Institute for Energy Studies,* https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/04/Turkeys-gas-demand-decline-reasons-and-consequences-OIES-Energy-Insight.pdf

2017 – from 28 to 14 bcm. The segment has been opened for competition (67 importers at EU borders in 2017) and leading European companies have already launched their operations in Ukraine.

Ukraine's gas consumption stood at 32.28 bcm in 2018, recording a 3% increase, compared to 2017 levels. The country's gas production reached 20 bcm in 2018, a fall of 2% in comparison to 2017.

Since 2005 up to 2015, Ukraine's net gas imports fell sharply; from 48,263 ktoe or 57.45 bcm in 2005 to 13,292 ktoe or 15.82 bcm in 2015. The share of gas imports from Russia displayed the highest decrease in the period between 2011 and 2015, mainly due to the lower gas demand and Ukraine's import diversification policy. At the same time, gas imports from EU (Hungary, Slovakia and Poland) increased from 0 bcm in 2011 to 11.3 bcm in 2015. The diversification of the gas imports was mainly driven by political issues and supported by EBRD and World Bank loans for gas consumption from prequalified EU-based suppliers. Figure 67 depicts Ukraine's gas balance from 2002 to 2016.

Figure 67: Gas Consumption and Imports in Ukraine, 1991-2017



Source: PwC

Table 26: Natural Gas Demand and Supply in Ukraine, 2018

bcm	Gas
Production	20.0
Imports	12.28
Consumption	32.28

Sources: IENE and BBSPA

Ukraine's Gas Outlook

Gas consumption in Ukraine is estimated to remain relatively stable by 2035 at 34 bcm, with a gas production of about 18 bcm, zero gas imports from Russia and net imports of about 16 bcm from the EU[25].

(h) Albania

Gas Demand and Supply

In 2018, Albania's gas consumption was 0.09 bcm, remaining stable compared to 2016 and 2017 levels, while its gas production stood at 0.1 bcm in 2018. Albania has an existing onshore gas field at Delvina close to Durres with the domestic gas sold to its petrochemical industry. The precise production numbers are uncertain but public reports suggests that production is less than 10 mmcm of associated gas per year, which is minimal. Prospects for new gas finds exists; however, no significant drilling has taken place so far and volume of production is uncertain.

The TAP pipeline, which is expected to be completed in 2020, will provide first gas supplies. It is also not clear at this stage which entities would provide the necessary anchor load for any gas supply contract to materialise from TAP. However, the main anchor consumers will be inevitably located close to TAP with offtake from TAP.

Albania's government has shown strong interest in the country's gasification; however, no significant projects (other than TAP) are currently ongoing. One immediate project that could be developed is the connection of TAP's offtake point at Fier with the dual fuel power plant at Vlore. However, funding for this pipeline is still uncertain.

The country's government and its regulatory authority are now in the process of drafting the necessary regulatory and market framework documentation to enable the gas market to develop. So far, no details about a transmission tariff methodology, market design and market rules are available. The most comprehensive and up-to-date document setting Albania's gas sector development ambitions is the Gas Masterplan. The Masterplan contains details on supply/demand assessments and importantly a detailed gas transmission plan.

Albania's Gas Outlook

According to the Masterplan[26], the gas demand potential in Albania is close to 1.5 bcm in 2020 rising to nearly 3 bcm in 2040. This can be characterized as a very sizeable market. The Masterplan, however, notes that the aforementioned gas demand potential is unlikely to materialise. The actual demand forecast for 2020 is 1.2 bcm and for 2040 is 2.2 bcm.

[25] KPMG (2017), "Situation of the Ukrainian natural gas market and transit system", https://www.nord-stream2.com/media/documents/pdf/en/2017/04/kpmg-situation-of-the-ukrainian-natural-gas-market-and-transit-system-2017-04-10.pdf

[26] https://www.infrastruktura.gov.al/wp-content/uploads/2017/12/WB11-ALB-ENE-01_final_GMP_2016_11_24.pdf

(i) Bosnia and Herzegovina

Gas Demand and Supply

In 2018, Bosnia's gas consumption was 0.24 bcm, remaining stable compared to 2017 levels. Bosnia and Herzegovina lacks any domestic sources of natural gas; therefore, there is no gas production industry and gas is fully supplied to Bosnia by Russia via Serbia. The gas market in Bosnia and Herzegovina is small and fragmented. Gas demand only exists in Sarajevo (and to a lesser extent) in Zenica. The gas system consists of one pipeline that feeds into Sarajevo and is connected with Serbia with an approximate technical capacity of 0.75 bcm/year. This pipeline accounts for all Bosnia's gas demand. There is no gas storage infrastructure and no LNG opportunities. Currently, no gas is used in power generation.

Bosnia's Gas Outlook

According to the ENTSO-G[27], the gas demand potential in Bosnia and Herzegovina will range from 0.12 bcm to 0.30 bcm in 2030, based on four scenarios.

5.3. Planned Major Gas Infrastructure Projects in SE Europe

Natural gas pipelines have been a hot topic lately in the European energy agenda, a region heavily dependent on Russian gas supply. For instance, Bulgaria and Greece launched the construction of the €220 million Interconnector Greece-Bulgaria, while Serbia's energy minister said his country plans to build a natural gas pipeline connecting Belgrade to Banja Luka in Bosnia. The present study will attempt to chart progress made so far in all different gas infrastructure projects in SE Europe, but also discuss the serious challenges which lie ahead.

Based on data of October 2019, 90.5% of the **Trans Adriatic Pipeline (TAP)** project has been completed **(26)**, while 10% of the respective offshore part of the pipeline under the Adriatic Sea has also been constructed. The overall construction phase of the project is expected to be completed in the second half of 2019, as Italian Prime Minister Giuseppe Conte has given the green light for the completion of the TAP pipeline, expressing his support after many months of negotiations and constant concern over the objections of the Italian side. TAP is a project worth a total of €4.5 billion. The TAP pipeline will transport Caspian natural gas to Europe, connecting with the Trans Anatolian Pipeline (TANAP) at the Greek-Turkish border crossing Northern Greece, Albania and the Adriatic Sea before coming ashore in Southern Italy to connect to the Italian natural gas network.

Once built, TAP will provide important new energy supplies to SE Europe very much needed to power its homes and industries as the region transitions to a low-carbon future. Natural gas is the cleanest fossil fuel and will continue to play an important role in Europe's future energy mix helping to replace more carbon intensive sources of energy. It will also increase energy security by diversifying EU's energy supplies. For instance, on completion, TAP will

[27] https://www.entsog.eu/sites/default/files/files-old-website/publications/TYNDP/2017/entsog_tyndp_2017_main_170428_web_xs.pdf

provide an estimated 33% of Bulgaria's gas needs, 20% of Greece and approximately 10.5% of Italy. **(27)**

It is worth noting that the TAP AG, a company established to plan, develop and build the TAP pipeline, and the Greek National Gas System Operator (DESFA) signed an agreement on the maintenance of Greek section of the TAP pipeline, which was ratified by the competent Regulatory Authority for Energy (RAE) on December 12, 2018, while the TAP and the TANAP successfully completed their connection in early November 2018 with the final "golden weld", which physically connected the two pipelines. It is worth noting that the TANAP is already in operation since June 12, 2018.

The **Turkish Stream**, with its onshore leg still under construction, will supply Russian gas to Turkey via the Black Sea and is expected to be operational by the end of this year upon completion of the construction of its onshore part on Turkish territory. The Turkish Stream project consists of two lines across the Black Sea, the first of which will serve Turkey with a capacity of 15.75 bcm, while the second line, of the same capacity, is planned to serve Europe. Each pipeline is 930 kilometers in length, laid at depths reaching 2,200 meters. The project is the biggest-diameter offshore gas pipeline in the world laid at such depths. The deep-sea pipe-laying was carried out by Pioneering Spirit, the world's biggest gas pipeline laying vessel.

On November 19, 2018, Istanbul hosted the ceremony of completion of the construction of the offshore section of the Turkish Stream. The seabed section is 910 km long and the land section will run 180 km into Turkey. The project is estimated at a total of €11.4 billion. **(28)**

On December 21, 2018, Bulgartransgaz, Bulgaria's gas transmission and storage system operator, launched a public procurement procedure for the construction of the so-called Bulgarian section of Turkish Stream. During the following day, the country's Energy Regulator gave permission for the state-owned company to start pre-selling the pipeline capacity, the funds from which will be used to finance the project. The Bulgarian part of the Turkish Stream envisages over 480 km of gas pipeline and two new compressor stations at Provadia and Rasovo. **(29)**

In May 2019, Russian Gazprom confirmed that the first quantities of gas – estimated at 15.75 bcm per year – will be fed through the Turkish Stream pipeline to Turkey by December 31. More specifically, the pipeline will be ready for testing in November, while the goal is to launch commercial operations in the last ten days of December, according to Mr. Vitaly Markelov, the vice-president of Gazprom. It is planned that the second leg of the Turkish Stream pipeline will feed the SE European market after 2021, with an additional quantity of 15.75 bcm. This quantity will more than offset the quantities delivered to Bulgaria, Greece, Turkey and North Macedonia via the Trans Balkan pipeline, the future of which remains uncertain. **(30)**

One more project under construction is the **Interconnector Greece-Bulgaria (IGB)** which consists of a cross-border and bi-directional gas pipeline, connecting the Greek gas network with the Bulgarian gas network. The annual capacity of the gas pipeline is foreseen to be up to 5 bcm, with an initial capacity of 3 bcm. The IGB inauguration ceremony took place in Bulgaria’s Kirkovo on May 22, 2019. On October 10, 2019, an inter-governmental agreement was signed in Sofia by the two countries' energy ministers. Earlier in May, ICGB AD, the company that will construct, own and operate the IGB, has chosen following a tender Greece’s J&P AVAX as EPC contractor **(31).** As Mrs. Corina Creţu, European Commissioner for Regional Policy, recently announced, about €33 million of EU funds are expected to be used in order to finance part of the construction of the IGB project.

At first glance, the biggest obstacles to the construction of the **East Med pipeline**, which consists of an offshore and onshore pipeline that will connect the East Mediterranean gas resources to the European system, are related to the pricing issues, the ability to ensure adequate gas volumes for exports as well as technical challenges. In November 2018, Israel’s Energy Minister Mr. Yuval Steinitz attempted to ease fears about construction issues and suggested that East Med can be completed by 2025 **(32)**. Also, Greece’s Energy Minister Mr. George Stathakis said in December 2018 that the East Med pipeline is "technically and economically viable”, enjoys the support of all the other countries involved as well as the European Commission and would allow Israel and Cyprus to transport their proven hydrocarbon reserves as well as Greece’s potential reserves to the European market. Studies conducted so far indicate that the project’s construction cost could reach €8 billion, while it is currently classified as a Project of Common Interest (PCI) by the EU. **(33)**

The East Med pipeline will be able to carry roughly 8 bcm/y. It is worth noting that the leaders of Greece, Cyprus and Israel met in Jerusalem on March 21, 2019 during the 6th Trilateral Greece-Cyprus-Israel Summit, which was also attended by the US Secretary of State Mr. Mike Pompeo, and agreed upon the significance of the pipeline. The presence of Mr. Pompeo signaled the full support of the US to the cooperation between Greece, Cyprus and Israel, as the US administration is committed in promoting energy security in SE Europe.

In addition, the **Vertical Corridor** emerges as a broad gas interconnectivity concept of all countries concerned, including Greece, Turkey, Bulgaria, North Macedonia, Serbia, Romania and Hungary. The Vertical Corridor concept does not concern a single pipeline project, but involves rather a gas system that will connect the existing national gas grids and other gas infrastructure in order to enhance energy security and ensure liquidity. Initially, the Vertical Corridor will be used to transport some 3-5 bcm per year but later could transfer some 8 bcm.

In May 2015, IENE completed an initial study on “The Vertical Corridor - From the Aegean to the Baltic”, which attempted an all-round investigation of the existing and prospective gas infrastructure of the SEE region and its relevance to the development of the Vertical Corridor system of gas pipelines, as agreed at political level in November 2014 by Greece, Bulgaria and Romania. This IENE study provides a detailed analysis at both technical and economic level of the main parameters involved for the implementation of what appears to be a very challenging project. As it became clear from the study, the construction of new components for this system will require minimal work, whether pipelines, compressor stations, branches or metering stations since at the same time serve the needs of local gas networks **(34)**. The broad concept of the Vertical Corridor being to facilitate the movement of gas from north to south and vice-versa by enhancing the use of existing infrastructure in all countries concerned and by constructing layovers where necessary.

On September 28, 2017, Bulgaria, Romania, Hungary and Austria signed a memorandum of understanding to proceed with implementation of BRUA gas link project that seems to replace the afrorementioned Vertical Corridor. Under the memorandum, all countries have agreed on a reverse-flow gas interconnection. Romania has issued a building permit for the BRUA project on its territory and has conducted procedures for assigning the construction works **(35)**. The pipeline will have a total length of 528 km and its Romanian section is expected to be completed by the end of 2020.

In addition, Romania's gas TSO Transgaz secured a €50 million loan from the European Investment Bank (EIB) in order to finance the first stage of the BRUA project, which is expected to link the Black Sea gas fields with Austria. The amount refers to the disbursement of the first tranche, as the total amount will be in the region of €150 million.

On June 5, 2019, Romania's President Mr. Klaus Iohannis emphasized the importance of the actual implementation of the projects launched at the Three Seas Initiative Summit that took place in 2018 in Bucharest and indicated that the BRUA gas pipeline could be one of the steps through which Romania can become the main security provider in the region. **(36)**

Map 17: BRUA Corridor

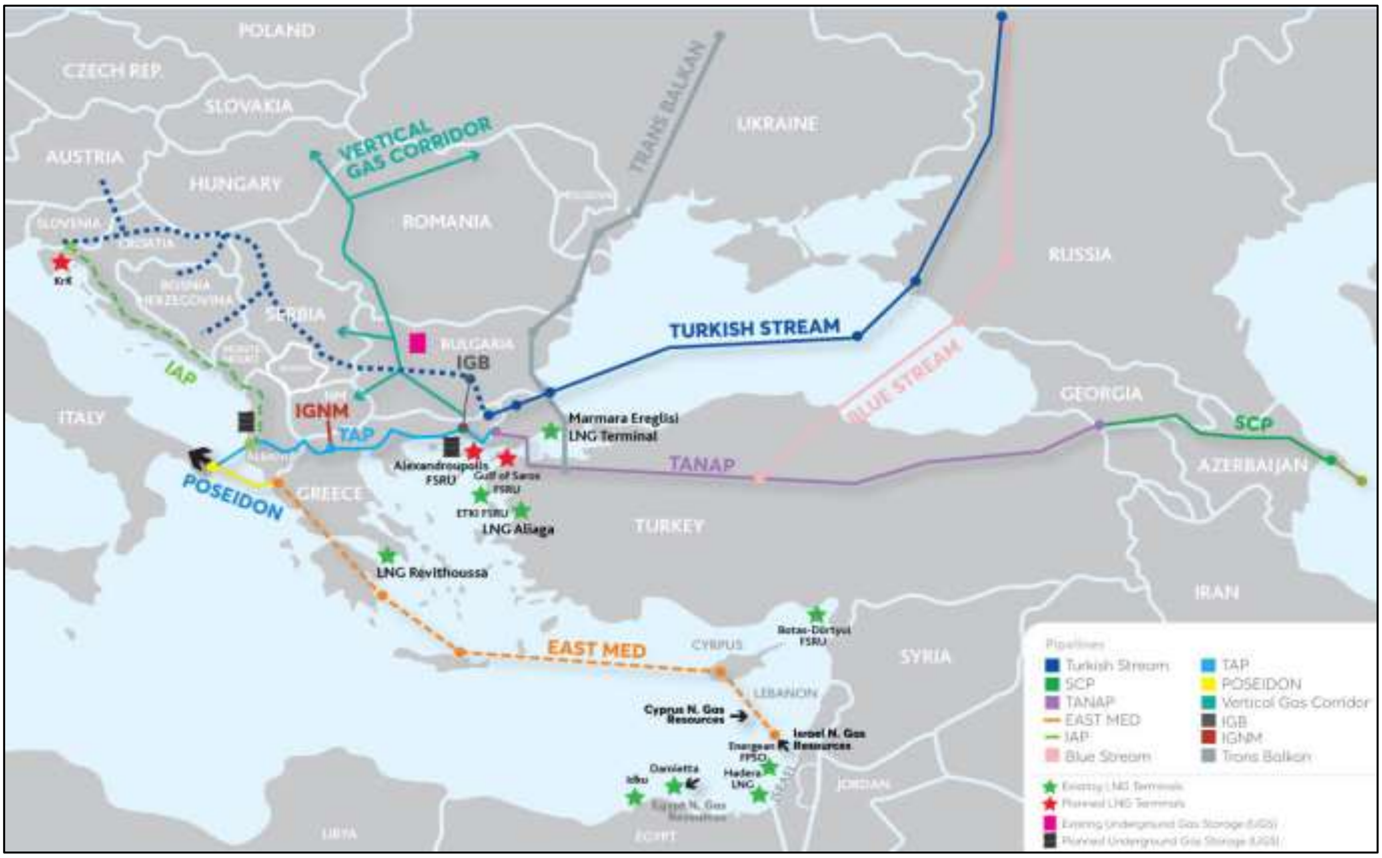
Source: European Commission

In addition, there are some very important planned gas infrastructure projects in SE Europe, including the **Interconnector Greece-North Macedonia**, which will enhance the diversification of North Macedonia's gas supplies as the country is solely dependent on the Trans Balkan Pipeline as well as Greece's **underground gas storage project in the depleted gas field in South Kavala**, which is expected to "collaborate" with both the planned FSRU in Alexandroupolis and the existing LNG terminal at Revithoussa, Greece's sole LNG terminal that completed its expansion in November 2018.

In parallel and in view of several new projects under development in the region, it is time to **redefine the South Corridor**, as this has already been suggested by IENE, by including these planned and new potential gas supply sources and routes. Therefore, an **Expanded South**

Corridor, as shown in Map 18, may be considered and defined as such, to include all major gas trunk pipelines and LNG terminals.

Map 18: The Expanded South Corridor



NB.: The TANAP has been completed, while TAP, Turkish Stream, BRUA and IGB are under construction. The IAP, the IGI Poseidon in connection with East Med pipeline and the Vertical Corridor and the IGF are still in the study phase. Blue Stream and Trans Balkan are existing pipelines.

Source: IENE

The Role of LNG in SE Europe

It appears that LNG prospects in SE Europe and the East Mediterranean in particular, are far better placed than they were five years ago with new projects getting ready to progress and LNG clearly emerging as a fuel of choice for several industrial consumer groups helped by lower prices and increased availability.

In SE Europe, LNG seems to be a realistic alternative fuel as it increases security of supply through multiple and independent supply sources, provides the opportunity for new LNG suppliers (e.g. Australia, US, etc.) to export gas to the region, enhances pricing flexibility and safer gas transportation and can also support underperforming gas pipeline projects. It is worth noting that on December 30, 2018, Greece's Revithoussa LNG terminal, following an agreement between Cheniere and DEPA, welcomed the first US LNG cargo at its newly build 3rd tank of 95.000-m^3 storage capacity. Thus, the Revithoussa LNG terminal opens up the way for new prospects in gas supply by differentiating energy sources and enhancing security of supply in SE Europe, enabling Greece to become a gas hub for the wider region.

On May 30, 2019, Greece’s Public Power Corporation (PPC) held a tender for the purchase of 130,000 cubic meters of LNG with five providers submitting bids and with the best offer tabled by Shell. The LNG will be stored at the Revithoussa terminal. The quantity is expected to be consumed within July 2019 by the power utility's units. According to a PPC press release, the net benefit for the utility amounts to €11 million, when compared to the average contract price for similar LNG portfolios. **(37)**

It is thus anticipated that the SE European region will play a significant role in expanding LNG trade in Europe by 2020 through the construction and operation of several new LNG regasification projects such as the FSRU unit that is planned to be located offshore in Alexandroupolis, in Northern Greece, with the prospect of feeding gas quantities into the Greek, Bulgarian, Serbian and Turkish gas systems, among others.

Regarding the Alexandroupolis FSRU, Gastrade, the promoter of the project, is close to launching a binding second-round market test for annual capacity reservations, seen taking place within the next few weeks **(38)**. The company has requested the approval of market-test guidelines and regulations from Greece’s Regulatory Authority for Energy (RAE). Once this stage has been completed, participants will receive a series of related documents covering issues such as capacity reservation and guarantees. Pricing policy is among the matters that have been discussed between Gastrade and RAE in the lead-up. Gastrade has opted for a flexible pricing policy, promising users a range of choices on aspects such as LNG quantities, products and commitment durations. Binding second-round market test participants will be given approximately two months to make their capacity reservations for the LNG terminal, sources have estimated. The market test’s first round, a non-binding stage, was completed on December 31, 2018. Twenty firms based in various parts of the wider region, as well as major international gas traders, expressed interest for annual capacity reservations totaling 12.2 bcm, which exceeded the project’s planned regasification capacity of 5.5 bcm.

One further FSRU project in Greece is now in the planning stage and it is promoted by Motor Oil Hellas, a major refining and oil marketing group. This latest FSRU project, which received its approval by RAE on March 5, 2019, is to be located offshore in the Agioi Theodoroi area, near Motor Oil’s refinery **(39)**. The capacity of the FSRU tank will be 135,000-170,000 m^3, while its regasification capacity peak is expected to be 470,000 Nm^3/h.

Cyprus provides an interesting LNG paradox. In August 2019, the country selected contractors (led by consortium of JV China Petroleum Pipeline Engineering Co Ltd, AKTOR S.A. and METRON S.A., with Hudong-Zhonghua Shipbuilding Co. Ltd and Wilhelmsen Ship Management Limited) as preferred bidders to develop a 2.5 bcm/y FSRU to be located offshore in Vasilikos Bay, near Limassol, along with jetty mooring and pipeline infrastructure. The c. €300 million investment costs are being met by the EU with grants of €105.8 million (from CEF) and €10 million (from the European Energy Programme for Recovery or EEPR) with the remainder from the participants in the import terminal. A separate Expression of Interest process has been launched for LNG supply to the project, the results of which are expected by the end of 2019. Concurrently, Cyprus has revived discussions around plans to develop an LNG export project (either onshore or floating) to monetise recent gas discoveries in Cyprus' EEZ – notably the 2011 discovery of the Aphrodite gas field, as well as more recent discoveries named Calypso and Glaucos-1. **(40)**

Turkey's first FRSU terminal in Aliağa (i.e. ETKI FSRU), north of the port city of Izmir on the country's Aegean coast, launched operations in December 2016. The 145,000 m^3 LNG storage capacity vessel is operated by the Turkish construction companies Kolin and Kalyon with a 20 mcm of send-out capacity per day. In addition, the Botas-Dörtyol FSRU, the world's largest FSRU in operation in the Turkish port of Dörtyol, a district in the southern province of Hatay, started its operation in February 2018 as the country's second FSRU terminal. The FSRU has an LNG storage capacity of 263,000 cubic meters and has re-shipment and gas transfer capabilities, with a regas discharge capacity of 540 mcm per day. Turkey has also two land-based LNG terminals (i.e. Aliaga and Marmara Ereglisi). Thus, Greece and Turkey are the only countries in the broader Black Sea-SE European region which at present possess LNG gasification terminals which are well linked and integrated into their national gas systems (see Map 19).

Map 19: LNG Terminals in SE Europe

Source: IENE

There is also a very important LNG bunkering project in SE Europe, known as Poseidon II LNG Bunkering Project, which is a continuation of Poseidon Med and the Archipelago LNG projects, which all together are part of the Global Project aiming to take all the necessary steps towards adoption of LNG as marine fuel in East Mediterranean Sea, while making Greece an international marine bunkering and distribution LNG hub in SE Europe. The Action will build on the achievements of the aforementioned projects as well as on the results of Poseidon Med I, which delivered the Master Plan for LNG as a marine fuel in the Mediterranean region. The major objective of the project is to contribute in reducing negative impacts of heavy fuel oil used for power generation and to facilitate the implementation of the requirements of a number of EU Directives regarding alternative fuels for a sustainable future in the shipping industry as well as the distribution of LNG in six main ports (i.e. Piraeus, Patra, Heraklion, Igoumenitsa, Limassol and Venice), as Map 20 illustrates.

Poseidon Med II, with Greece's Public Gas Corporation (DEPA) being its coordinator, is financed by the Connecting Europe Facility (CEF), a key EU funding instrument that supports trans-European networks and infrastructures in the sectors of energy, transport and telecommunications. This project will last for 5 years with the participation of 26 companies from three EU member states (i.e. Greece, Cyprus and Italy). The start date of this Action was June 2015 and the end date is December 2020. Its estimated total cost is roughly €53 million and the percentage of EU support is 50% (i.e. €26.6 million) **(41)**. In this context, Greece's DEPA received government approval on July 30, 2019 to build a small-scale LNG terminal at the port of Patras in western Greece. The development is part of a plan by Athens and the European Commission to make Greece into an LNG bunkering hub for southeastern Europe. The Patras facility, scheduled to come online at the end of 2020, will have a storage capacity of 3 mcm.

Map 20: Poseidon Med II LNG Bunkering Project

Source: DEPA

Table 27 shows the gas production and consumption in SE Europe in 2008, 2018 and 2025 (estimated), highlighting the low gas production and the need for the SEE countries to import increased natural gas volumes. What is evident is the substantial contribution of Turkey in total gas consumption in SE Europe, which is expected to increase further by 2025, corresponding to more than 63% of the total, based on IENE's estimates. Turkey is the region's major gas consumer and importer by far and its interest in natural gas is strong both as a potential producer but also as a transit country to European markets. On the transit side, virtually all of the various gas pipeline projects, which plan to transport Caspian gas to the European markets, involve Turkey as a transit country (e.g. TANAP and Turkish Stream).

Table 27: Natural Gas Production and Consumption in SE Europe (2008, 2018 and 2025e)

Country	2008		2018		2025e	
	Gas production (bcm/y)	Gas consumption (bcm/y)	Gas production (bcm/y)	Gas consumption (bcm/y)	Gas production (bcm/y)	Gas consumption (bcm/y)
Albania	0.02	0.02	0.1	0.09	0.01	0.22
Bosnia and Herzegovina	0.0	0.31	0.0	0.24	0.0	0.45
Bulgaria	0.31	3.5	0.01	3.04	0.21	4.3
Croatia	2.03	3.1	1.28	2.48	1.52	3.3
North Macedonia	0.0	0.05	0.0	0.18	0.0	0.6
Greece	0.0	4.25	0.1	4.87	0.0	6.0
Kosovo	0.0	0.0	0.0	0.0	0.0	0.0
Montenegro	0.0	0.0	0.0	0.0	0.0	0.0
Romania	11.2	16.9	10.26	11.97	10.02	14.1
Serbia	0.25	1.92	0.45	2.93	0.51	2.8
Slovenia	0.0	0.51	0.0	0.8	0.0	1.07
Turkey	1.03	36.9	0.51	49.64	0.73	56.0
Total	**14.84**	**67.46**	**12.71**	**76.60**	**13.00**	**88.84**

Sources: IENE, IEA, 10-year Development Plans of gas TSOs

What's Next

Attention is now focused on three major gas pipeline projects in SE Europe; two of them currently under construction (i.e. TAP and Turkish Stream) and one at an advanced design stage (i.e. East Med).

Even though several intergovernmental agreements were recently reached between the countries that are now interested in the **East Med pipeline project** (i.e. Greece, Israel, Italy and the Republic of Cyprus), there is no guarantee that the project will be on track soon. This, of course, does not mean that the East Med pipeline project should be re-examined or abandoned, since its existence on paper only helps strengthen a wider strategic alliance among the countries of the East Mediterranean region (including Egypt), which comes against Turkey's growing unease and expansioning aspirations in the region. In this context, the East Med pipeline project will remain for a long time a purely "political" project, with the prospect of being implemented if and only if there is a strong interest from one or more investors in order to create a well-funded consortium as well as the necessary conditions for the gas supply and distribution from the under-development gas fields of the East Mediterranean region can be met.

Regarding **Turkish Stream**, Bulgaria and Serbia have already proceeded to build the infrastructure for receiving gas since Russian Energy Minister Alexander Novak announced on July 26, 2019 that the second leg of the Turkish Stream pipeline will go through Bulgaria, Serbia and Hungary and not through Greece. More specifically, Bulgaria plans to complete the construction of the Balkan Stream, an offshoot of the Turkish Stream through Bulgaria to Serbia, by early 2020, Russia's Industry and Trade Minister Denis Manturov recently announced. Serbia has taken delivery of the pipes that will be used to construct its section of the Turkish Stream to carry Russian gas to Europe, the country's energy minister announced on May 21, 2019. Roughly 7,000 tonnes of pipes arrived on May 20 with some 50,000 tonnes more are expected to be delivered by December when the project is scheduled to be completed. **(42)**

Furthermore, Serbia plans to build a gas pipeline connecting Belgrade to Banja Luka, the main city of neighbouring Bosnia's Serb Republic entity, Serbia's energy minister added. The Belgrade-Banja Luka link will branch out from the gas transmission pipeline that Serbia is building from the border with Bulgaria to its border with Hungary as part of the Turkish Stream project of Russia's Gazprom.

In Serbia, the project for building a pipeline from the border with Bulgaria to the border with Hungary is carried out by Novi Sad-based Gastrans, a wholly-owned subsidiary of Swiss-based South Stream Serbia, according to data from Serbia's commercial register. Gazprom owns a 51% stake in South Stream Serbia, while state-owned Srbijagas holds the remaining 49%, according to Gazprom data. **(43)**

On June 14, 2019, Hungarian Minister of Foreign Affairs and Trade Mr. Péter Szijjártó and Serbia's Minister of Mining and Energy Mr. Aleksandar Antic signed an agreement on building a gas pipeline as a part of the Turkish Stream. Mr. Antic said that the construction works in Serbia are going on in three phases, and the pipeline from the border with Bulgaria to the boundary with Hungary will be finished by mid-December this year, while the Hungarian Minister said his country's part would be completed by the end of 2021. **(44)**

According to Mr. Stambolis **(45)**, plans for the expansion of Turkish Stream to Europe via the hub at the Greek-Turkish border seems to be in limbo. After 2019, Greece will be forced to increase its gas imports from Turkey via the Interconnector Greece-Turkey, which has been in operation since 2007 and has a sufficient capacity of 5.0 bcm, but no more than 1.5 bcm is expected to be used per annum over the next years. As of January 1, 2020, Greece may have to buy gas quantities of Turkish basket at significantly higher prices, if Gazprom stops gas flows through Trans Balkan pipeline, as it is anticipated. Alternatively, Greece will end up importing Russian gas from Bulgaria’s system.

Both Romania’s Transgaz and Bulgaria’s Bulgartransgaz derive significant revenues from transit of Russian gas through the Trans Balkan pipeline. For Transgaz, over the last 6 years, between 18%-20% of its total operating revenues came from transit operations. However, for Bulgartransgaz the revenue is very substantial, around 60% for the last 4 years. The reason for the disparity seems to be that Transgaz operates a much larger system handling larger domestic volumes and transit distance is much shorter. The Romanian market is almost four times the size of the Bulgarian one (11 bcm vs 3 bcm), and transit is only 200 km across Romania. **(46)**

With total proven reserves of 1.3 tcm, Azerbaijan is not considered as the country that will solve the problem of European energy supply (with the Eastern Mediterranean region possessing three times more reserves). However, Azerbaijan's export capacity, through the **SCP-TANAP-TAP system** and its gas treatment plants, will very soon become a reference point for the entire Caspian region, as part of a wider attempt to exploit export capacities of the neighbouring countries.

Table 28: Major Gas Pipeline Projects Under Construction in SE Europe

Project	Shareholders	Length	Cost	Capacity
TAP	BP (20%), SOCAR (20%), Snam S.p.A (20%), Fluxys (19%), Enagás (16%) and Axpo (5%)	878 km	€4.5 billion	10.0-20.0 bcm/y
IGB	BEH (50%), IGI Poseidon (50%)	182 km	€220 million	3.0-5.0 bcm/y
Turkish Stream	Gazprom, BOTAS	1,100 km	€11.4 billion	31.5 bcm/y*
Bulgaria-Romania-Hungary-Austria (BRUA)	Bulgartransgaz, Transgaz, FGSZ, Eustream, GCA	500 km	€500 million	6 bcm/y

This amount corresponds to the first two strings of the pipeline with an additional 31.5 bcm foreseen when strings 3 and 4 will be constructed and become operational.

Sources: IENE and involved energy companies

Following the landmark energy agreement signed between the Caspian Sea countries of Russia, Azerbaijan, Iran, Kazakhstan and Turkmenistan in August 2018 **(47)**, Turkmenistan and Iran are already in negotiations with Baku for the exploitation of Azerbaijan's gas network in order to export large quantities of gas through Turkey to European markets. With Azerbaijan and Turkmenistan currently discussing the transportation of limited gas quantities (i.e. 3-5 bcm) through the existing underwater pipeline network and through the construction of the planned Trans Caspian Pipeline (see Map 21). Thus, Azerbaijan is anticipated to play an important role as a major hub for the transportation and promotion of natural gas from the wider Caspian region to the West **(48)**. On July 1, 2019, TAP launched a market test to allow natural gas shippers to express interest and potentially secure access to new, long-term capacity in TAP. The market test includes two phases: (a) non-binding phase, as of July 1, 2019 and (b) binding phase, which is expected to start in Q2 2020 at the earliest. The results of the non-binding first-round market test, concerning a possible capacity boost of the TAP pipeline, justify an increase from 10 bcm to 20 bcm. Procedures for the second-round market test, whose result will determine whether a pipeline capacity increase will be carried out, and if so, its extent, are already underway.

Map 21: Trans-Caspian Gas Pipeline and the Caspian Sea Region

Source: Financial Times

Over the last 10-12 years, we have seen the emergence of a number of projects involving the construction of major, and smaller, gas pipelines across SE Europe. Most of these projects have evolved around the so-called South Corridor. Some of these projects, grand in formulation and ambitious in terms of deliverable gas volumes, have collapsed (e.g. the Nabucco pipeline), while others have been mothballed (e.g. the ITGI). Other grandiose schemes, such as the South Stream, although strictly speaking outside the remit of the South Corridor, but of relative importance, have been cancelled and pushed aside mostly due to political considerations, part of the never-ending East-West (read USA/EU-Russia) wrangle.

At the same time, entirely new projects have come about, of smaller scale but of great strategic value, such as the BRUA pipeline, and the various interconnection projects in the East Balkans (e.g. Interconnector Greece-Bulgaria and Interconnector Greece-North Macedonia[28]). There are also relatively new highly challenging projects such as the East Med pipeline or the FSRU in Alexandroupolis which add a totally new dimension to the region's energy capabilities and help enhance its role as a vital energy bridge between East and Southeast and the Western European markets. The latest developments on gas infrastructure projects in SE Europe bring closer to reality the concept of an integrated Expanded South Corridor.

5.4. Available and Planned Storage Capacity

(a) Greece's Gas Storage Projects

South Kavala Underground Gas Storage

Further benefits will occur through the potential development of an underground gas storage facility in the South Kavala gas field, which is currently being planned, and is in very close proximity to the under-construction TAP pipeline. Three major firms, each specializing in its own respective field, have formed a consortium to seek a contract to develop and operate the depleted gas field as an underground gas storage facility.

More specifically, Storengy, belonging to France's Engie group, Energean Oil & Gas, holder of a license for the South Kavala field, and technical firm Gek Terna are the three players joining forces for this contract, to be offered through a tender being prepared by the privatization fund HRADF. Underground gas storage facilities play a key role in subduing carbon emissions as a result of the flexibility they offer to renewable energy sources. Consortium member Storengy is Europe's biggest developer and operator of underground gas storage facilities. It currently operates 21 such facilities of all types on the continent.

[28] Greece's DESFA is preparing to launch a market test for the development of a Greek-North Macedonian gas pipeline interconnection running from Nea Mesimvria, on Thessaloniki's western outskirts, to Gevgelija, in the neighboring country's southeast. Windows International Hellas, an enterprise controlled by Russian entrepreneur Leonid Lebedev, which, in the past, has expressed interest for a rival project, has yet to emerge with any new action. An alternative project from Windows International Hellas would be developed as an independent gas system, whereas DESFA's proposal is planned to be incorporated into the national gas grid. RAE approved both project plans at the beginning of this year following two years of processing and consideration. However, DESFA was asked to conduct a market test as the cost of the project, if developed by the operator, would, as a national grid project, be passed on to users. The project, budgeted at €48.7 million and planned to stretch 120 km for a 3 bcm capacity, is seen as a source-diversifying initiative.

Offering a capacity of between 360 and 1,000 million cubic meters, or 10% of annual gas consumption in Greece, the South Kavala underground gas storage facility will require an investment of between €300 and €400 million to develop. The project has been granted PCI status by the European Commission, enabling EU funding support.

The underground gas storage facility in South Kavala together with Revithoussa LNG storage will fulfil the obligation on Member States to cover the maximum daily consumption in the event of disruption of the single largest gas import infrastructure with possible occurrence once in 20 years. The South Kavala underground gas storage facility is ideally positioned to support major gas pipelines and interconnectors (e.g. TAP and IGB) or act as an entry point for new offshore gas projects in the East Mediterranean region.

A tender for the utilization of the depleted gas field in the offshore South Kavala region as an underground gas storage facility appears headed for a slight delay and could be launched in early 2020, instead of late 2019, as a result of a deadline extension, from August 28 to September 9, granted to participants of a preceding tender looking to appoint a technical consultant for the project.

In November 2019, Greece's Environment and Energy Ministry signed a long-awaited ministerial decision for the development of the South Kavala UGS. The ministerial decision essentially outlines the legal terms concerning the facility's operation, including licensing requirements for development and exploitation.

The technical consultant will be tasked with preparing the tender's details and offering HRADF advice on the level of appropriateness of the plan to convert the depleted natural gas field into a gas storage facility, its equipment and interconnection needs, and other matters.

Expansion of Revithoussa LNG Terminal

The Revithoussa LNG Terminal is the only LNG terminal in Greece. It is located on the island of Revithoussa, in the Gulf of Megara, west of Athens. It was completed in 1999 and is operated by DESFA.

In November 2018, Greece's gas grid operator DESFA-run Revithoussa LNG terminal inaugurated its third storage tank significantly bumping the facility's storage capacity. The project was built in two stages, with the construction of a combined heat and power plant followed by the extension of the storage capacity of the facility. The second stage included the construction of a third LNG storage tank, the upgrade of marine facilities and the installation of additional technology equipment to increase gasification, a statement by the European Commission notes. The European Commission supported the project with €40 million from its Cohesion Policy funds. The third tank boosted the facility's storage capacity to 225,000 cubic meters in total with the regasification capacity jumping some 40%. Facilities to provide large- and small-scale reloading services are under construction at Revithoussa, and the terminal also plans to offer truck loading services by 2022.

(b) Bulgarian Gas Storage Projects

Chiren Underground Storage Facility

Currently, Bulgaria operates only one underground gas storage facility (i.e. Chiren), with a capacity of 0.5 bcm, owned by the gas TSO Bulgartransgaz. It is located in northwestern Bulgaria, about 400 km away from the Black Sea. Its storage capacity has been in decline, having been in use since 1974. Most of the volume of this facility is booked for mandatory reserves by state-owned Bulgargaz (sole supplier of natural gas in Bulgaria) and by Bulgartransgaz itself, and it is used to the cover seasonal fluctuation of natural gas consumption. Although there are plans to expand the Chiren facility using the EU Project of Common Interest funds, nothing has yet been done. **(49)**

Galata offshore Gas Storage

There is another site that has recently become a good candidate for conversion into a storage facility: the Bulgarian section of the Black Sea known as the Galata Exploration Block. The block comprises four offshore fields (Galata, Kaliakra, Kavarna and Kavarna East), with current remaining reserves standing at cca. 1 bcm. According to Petroceltic Bulgaria, the company holding the oil and gas exploration permit for the block, the Galata field has already been transformed into a gas storage facility, save for some changes that need to be made. After its full conversion, its full storage potential capacity would range between 1.3-2.2 bcm. The Galata block is located 22 km offshore, near Varna. It is close to the Bulgarian natural gas transmission system and Russian gas transit pipelines. It has the potential to be a steppingstone for the Bulgarian 'Balkan' gas hub, as it could store gas from a variety of sources: Romanian Black Sea offshore gas, Azeri gas from IGB or even Russian gas.

(c) Romanian Gas Storage Projects

Romania has eight storage facilities with a combined capacity close to 3.2 bcm of natural gas, mainly used to cover for increased consumption in the winter months. Six of Romania's facilities (with a total capacity of 2.76 bcm) are operated by Romgaz, through its special unit Depogaz, one by Depomures and one by Amgaz. Two of the six facilities are located in Central Romania, in Transylvania (Sarmasel and Cetatea de Balta) while the rest are in the South of the country (Bilciulesti, Balaceanca, Urziceni, Gherghesti), therefore most of them close to Bucharest, the capital of the city.

The current storage capacity in Romania is, however, not enough, if we assume a significant increase in domestic production in the next decade. Romania's Depogaz is planning to invest €720 million by 2022 to significantly expand capacity, especially along the BRUA pipeline. Considering the role that the BRUA pipeline would be serving, a network of gas storages would need to be distributed in the region to help better serve local needs and mitigate potential supply problems.

(d) Albanian Gas Storage Projects

The need for more storage in SE Europe goes hand in hand with advances in the gasification process. It is evident that the need for new storage will be greatest where new gasification occurs. Within this framework, the Albanian government is planning the development of an underground gas storage in the wider area of Dumrea. The UGS Dumrea project is to support and increase the flexibility of the existing and planned gas transmission system of Albania (including TAP project) with the existing and future projected gas transmission system of the neighboring countries. The project has a regional impact, as construction of the UGS Dumrea would facilitate not only gasification of Albania, but also the potential gasification of Montenegro and Kosovo and provide a diversified and reliable natural gas supply. This UGS project, of about 1 bcm capacity, would improve the preconditions for the further development of the natural gas markets in Albania. **(50)**

(e) Serbian Gas Storage Projects

In 2017, Serbia also announced its intention to expand the 0.45 bcm Banatski Dvor storage facility to 0.75-1 bcm. Gazprom is the majority owner of Banatski Dvor underground gas storage with 51% stake, while the state-owned Srbijagas controls the remaining 49%. In July 2017, Srbijagas and Gazprom signed a Memorandum of Understanding on the expansion of the storage facility. However, there are no further reports, confirming that works to this aim have started.

(f) Croatian Gas Storage Projects

Currently, Croatia has only one underground gas storage facility in Okoli, 50 km southeast of Zagreb, and it is managed by the national storage system operator - Plinacro's daughter company Podzemno skladište plina d.o.o. (PSP d.o.o.). Underground Gas Storage Okoli was put into trial run at the end of 1987, while in April 1988 the first cycle of gas injection began. After more than 20 years of doing business within INA, the Underground Gas Storage Okoli was organized as PSP d.o.o. at the start in early December 2008. On January 30, 2009, after signing the Agreement for the sale and purchase of business shares in PSP d.o.o. with INA, Plinacro acquired a 100% share in the company, the main activity of which is natural gas storage. **(51)**

Apart from its core business of gas storage, PSP d.o.o. is responsible for management, maintenance and development of a safe, reliable and efficient gas storage system, as well as for further development of storage capacities and storage operations. Croatia will improve the safety of the gas system of our country by carrying out development plans and new investment cycles of PSP, that is, by modernization and expansion of the compressor of the existing storage facility in Okoli and the construction of a peak gas storage facility in Grubišno Polje, as well as a future strategic underground gas storage facility.

(g) Turkish Gas Storage Projects

Turkey has two underground gas storage facilities; one at Marmara Silivri close to Istanbul, operated by TPAO, with 2.84 bcm storage capacity in two depleted gas fields (i.e. Kuzey Marmara and Değirmenköy) and one (i.e. Tuz Gölü underground gas storage) that is located 150 km south-east of Ankara, operated by BOTAŞ.

Turkey will increase its gas storage capacity at the Tuz Gölü underground gas storage facility from the current levels of 600 mcm to 5.4 bcm by 2023, according to Energy and Natural Resources Minister Fatih Dönmez. **(52)**

Table 29: Overview of Underground Gas Storage Facilities in SE Europe, 2018

	Number of UGS Facilities	Working gas capacity (bcm)	Max. withdrawal rate (mcm/d)
In Operation			
Bulgaria	1	0.6	4
Croatia	1	0.6	7
Romania	8	3.1	32
Serbia	1	0.5	5
Turkey	2	3.4	45
Total	**13**	**8.2**	**93**
Under Construction			
Serbia	1	0.3	5
Turkey	3	6.5	110
Total	**4**	**6.8**	**115**
Planned			
Bulgaria	1	0.5	4.6
Croatia	1	-	2.4
Greece	1	0.4	4.0
Romania	4	1.2	9.3
Turkey	3	5.5	57.6
Total	**10**	**7.6**	**77.9**
Potential			
Albania	2	1.3	6.5
Bosnia and Herzegovina	1	0.1	1.9
Turkey	1	1.0	16.1
Total	**4**	**2.4**	**24.5**

Source: CEDIGAZ (53)

6. Key Regional Players and Their Role in Gas Trading Hubs

As already discussed, several gas infrastructure projects in SE Europe are moving ahead and slowly but steadily building up the regional market and paving the way for the establishment of a natural gas hub in the region; thus, enhancing energy security and market competition.

Greece already operates the recently upgraded Revithoussa LNG terminal, close to Athens, which mainly imports from Algerian Sonatrach. At the same time, Turkey operates two land-based terminals and two FSRUs. The construction of the planned Alexandroupolis FSRU in North Greece will facilitate the access of SE Europe to more LNG quantities in addition to Greece's sole LNG terminal in Revithoussa.

Overall, these plans can work in conjunction with the IGB, which should be operational by late 2020, and will complement other regional interconnectors, such as those between Bulgaria-Romania, Bulgaria-Serbia, Turkey-Bulgaria, Romania-Serbia and Hungary-Romania.

Market integration will be facilitated in the first phase from the operation of the existing Interconnector Greece-Turkey, which already brings Azeri gas to Greece via Turkey and which is planned to have a reverse flow in order to facilitate deliveries to Turkey, which is by far the largest consumer of gas in the region, with estimates that it will need more than 80 bcm per year by 2025. Additionally, the East Mediterranean gas resources, mainly from Israel and Cyprus, over the course of the next 10 years, could provide much needed new gas inputs into the European energy grid in comparable, if not greater, quantities from those originating from Azerbaijan.

Consequently, sizable gas volumes will be entering SE Europe's system by 2023 and the case for gas price competition will become much stronger. On the other hand, for the gas hub vision to be realized, there needs to be sufficient spot gas traded in the region to form a reliable price index and not only gas volumes traded under oil-indexed long-term contracts. Any plans made to establish a gas trading hub in the region should take these developments into account, since most gas flow and trade will eventually end up in the Turkish, Greek and Bulgarian transmission systems. Some countries are likely to play a particularly important role in the formation of a regional trading hub and have the potential to make a real contribution to the market's integration and development.

6.1. Traditional and New Gas Suppliers and Their Role in Gas Trading Hubs

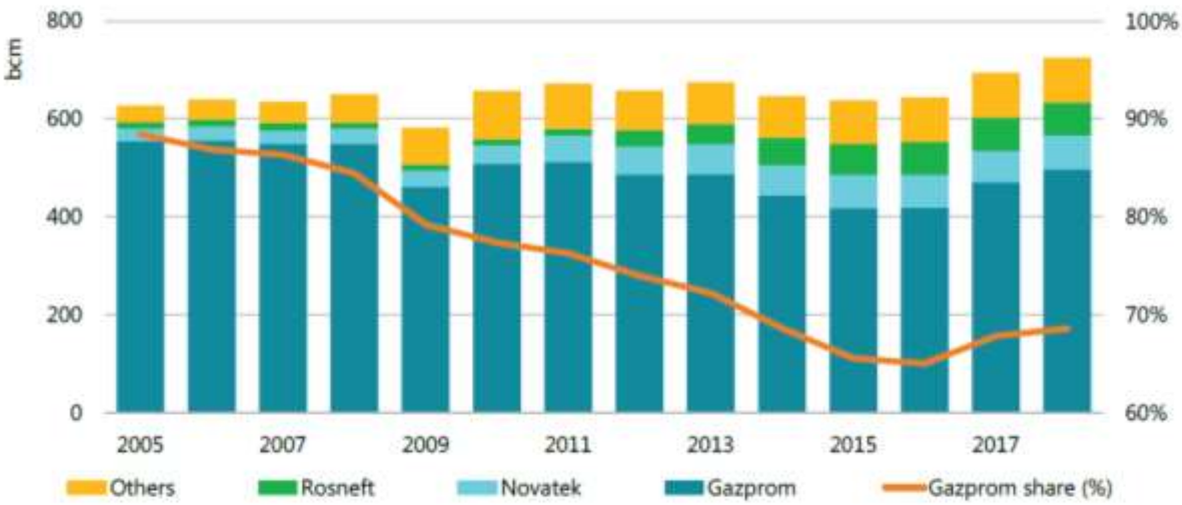
Russia

Russia accounts for more than one third of EU gas imports, making it the lead supplier of natural gas to the EU and particularly to SE Europe. While European demand growth will most likely remain weak, import dependence is slated to increase due to the decline in European gas production, meaning that the EU will have to rely ever more heavily on exporters such as Russia.

Russia's gas exports to Europe reached a record high in 2018 despite diplomatic tensions and the will of the European Union to reduce its dependence on Russia. Gazprom, which has a monopoly on exports through gas pipelines, sold 201 bcm of gas to Europe and Turkey in 2018, 3.5% more than in 2017. These exports represent the lion's share of Russia's sales to Europe. A smaller share, open to competition, was exported in the form of LNG.

As shown in Figure 68, Gazprom's share has declined from almost 90% in 2005 to 65% in 2016 as Novatek, Rosneft and other producers have been increasing their output. This trend has been reversed in the last two years and Gazprom's share is again on the rise. This can be explained with the increasing export volumes via pipeline – over which Gazprom holds a monopoly.

Figure 68: Russian Gas Production by Company, 2005–2018



Source: IEA

In the first quarter of 2019, Russian gas production increased by 3.3% to 197 bcm. Most of this was driven by Novatek, presumably amidst higher LNG exports from its Yamal LNG plant. Russian gas production is expected to grow at an average annual rate of 1% by 2024, driven by demand from export markets.

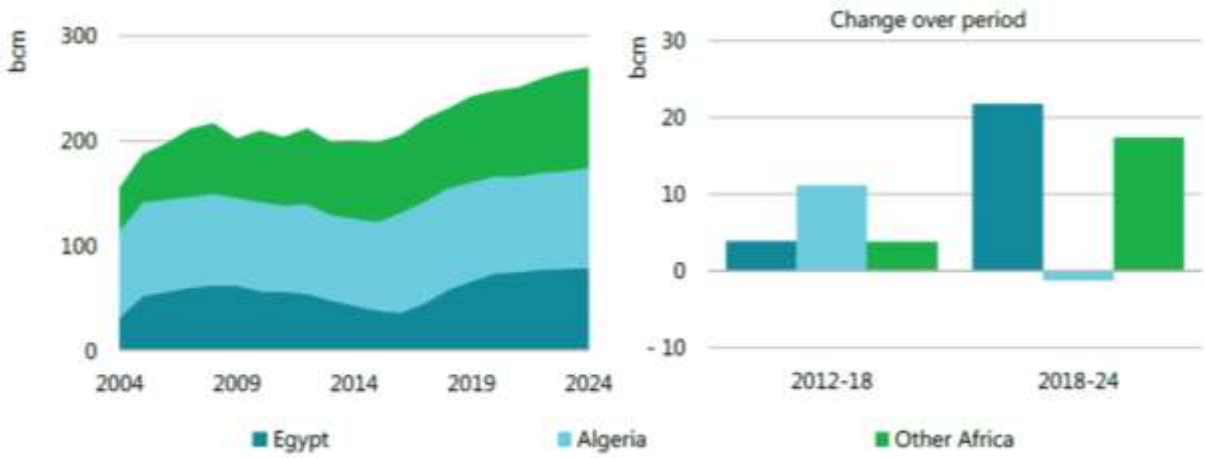
An important change in Russian gas production is the gradual shift away from the Nadym-Pur-Taz (NPT) region, which traditionally accounted for the majority of Russian gas output. According to Gazprom, the cumulative depletion level of fields located in NPT will reduce their share of the company's production portfolio from 70% in 2018 to about 60% by 2024/25. Hence, most of the incremental gas supply is expected to come from new areas of production. Amongst them, Gazprom's giant Bovanenkovskoye field in the district of Yamalo-Nenets has been the largest source of production growth in recent years; commissioned in 2012, the field delivered 84 bcm in 2017 and an estimated 90 bcm in 2018.

In spite of the strong production capacity development plans of Russian gas producers, IEA forecasts an additional net need of 45 bcm of annual production from Russia (primarily driven by exports as domestic demand declines), equivalent to an average 1% annual growth rate for the next five years.

Africa

According to IEA's 2019 Gas Report, gas production in Africa is expected to grow at an average rate of 2.7% per year over the next five years to reach over 270 bcm by 2024 (see Figure 69). Egypt will take the lead on production expansion, with several fields currently under development or in early phases of production. In Algeria, the absence of confirmed new developments to counterbalance the decline of historical fields' output leads to a slight reduction in production by 2024. Other developments are mainly driven by LNG export projects.

Figure 69: Gas Production in Africa, 2004–2024



Source: IEA

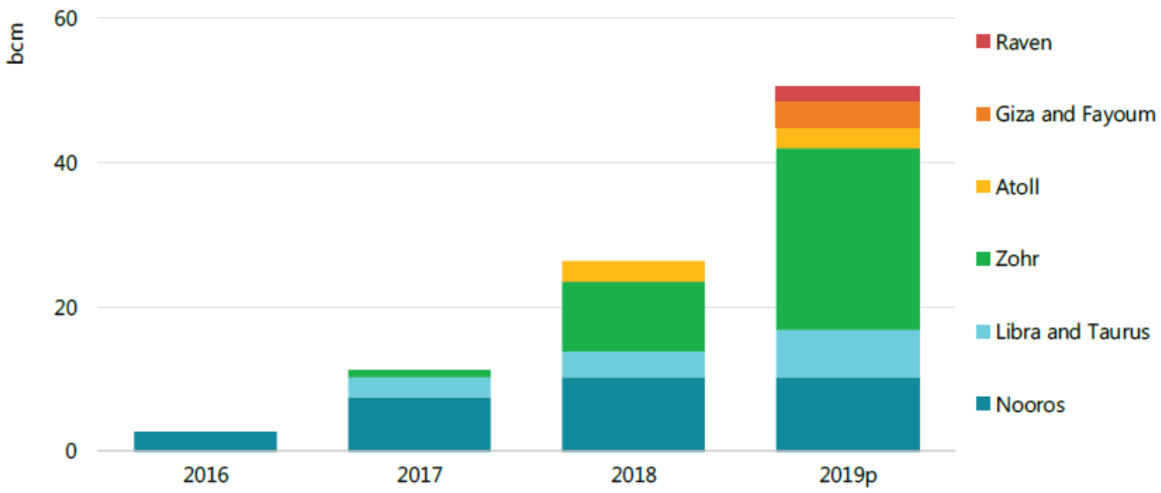
According to IEA's 2019 Gas Report, **Egypt**'s gas production rose to around 58 bcm in 2018, based on early estimates. According to Petroleum Minister Tarek El-Molla, the country achieved self-sufficiency by the end of September 2018, owing to the completion of new stages to increase gas production from four major fields in the Mediterranean Sea: Zohr, Nooros, Atoll and the first and second phases of the West Nile Delta complex.

The Zohr field became in 2018 the main asset in Egypt's gas production rebound, with production of about 10 bcm/y after commissioning in December 2017, on a par with the Nooros field which started operation in 2016 and reached its expected plateau level in 2018. According to Eni, which jointly operates Zohr with the state-owned Egyptian General Petroleum Corporation (EGPC), the field is set to reach production of around 28 bcm/y.

Several other fields were recently developed under BP-led operations: Atoll (close to Zohr's Shorouk offshore block), which delivered its first gas in February 2018, and the Giza and Fayoum fields in the second phase of the West Nile Delta (WND) complex in February 2019. With the expected start-up of the Raven field in late 2019, the three phases of WND are expected to deliver up to almost 15 bcm/y, equivalent to about one-quarter of Egypt's current gas production. All the gas produced will be fed into the national gas grid.

According to the Ministry of Petroleum, Egyptian gas production should reach the equivalent of almost 80 bcm/y in fiscal year 2019/2020. Based on current projects under development, this forecast does not share the ministry's optimistic outlook. It nevertheless expects strong growth until 2023 with a plateau of 77 bcm/y – or an average annual growth rate of 4.8% by 2024. However, Eni's discovery at Nour in March 2019 (under evaluation at the time of writing) may lead to further developments in the offshore Egyptian Mediterranean. In parallel, the government launched a bid round in March 2019 for ten blocks in the less-explored offshore Red Sea, according to IEA.

Figure 70: Gas Production from New Fields in Egypt, 2016–2019



Note: 2019 data are prospective.

Source: IEA

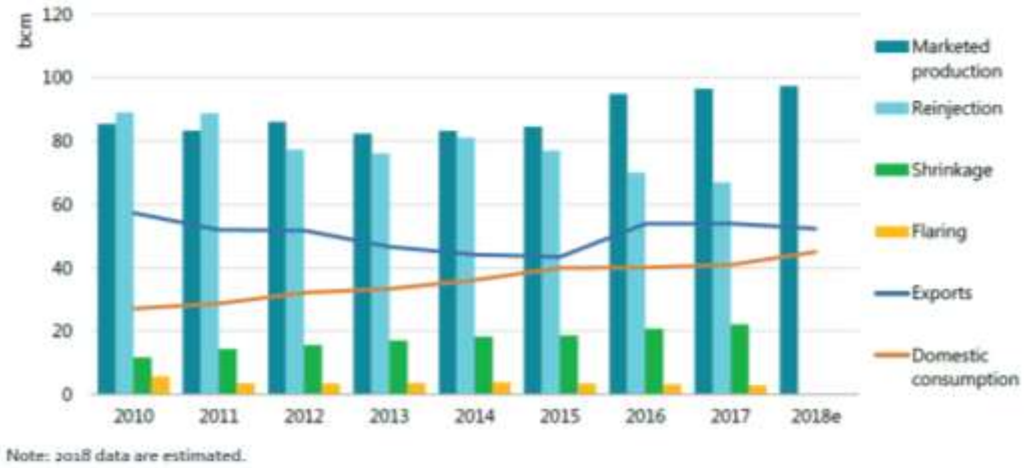
According to IEA's 2019 Gas Report, Algerian gas production is expected to stagnate and even slightly decrease by 2024 in spite of new production start-ups in 2019, due to the continuous decline of historical production. The country's marketed gas output remained stable over the recent past and even increased in 2016, but this was achieved thanks to a drastic reduction in gas reinjection – which accounted for most gross gas use until 2011. This shift was driven by the imperative of meeting the structural rise in domestic needs without impacting gas exports, which are a key source of revenues for Algeria's economy.

This drop-in reinjection is understood to have caused some damage to reservoir integrity and led to lower pressure and recovery in the Hassi R'Mel complex, the main historical contributor to Algeria's gas production. It accounted for up to 75% of the country's total gas production in the early 2000s. State-owned operator Sonatrach announced investment to prevent further decline, which is due to be completed in 2020.

New production assets have recently started production as part of the 9 bcm/y Southwest Gas project to counterbalance this decline: the Reggane and Timimoun fields both delivered their first gas in 2018, and the project's third and largest element, the 4.5 bcm/y Touat field, was expected to start deliveries by mid-2019.

However, the outlook remains uncertain in the absence of further announced developments to limit production decline over the medium term. This lack of production growth, combined with the expected continuous increase in domestic demand, has led to some concerns over Algeria's export capacity, as voiced in December 2018 by the then-Energy Minister Mustapha Guitouni, who highlighted the risk of seeing gas exports ending by 2032. Algeria has been preparing changes to its hydrocarbon law to attract greater foreign investment. These were expected during the first half of 2019, having been announced by the CEO of Sonatrach in late 2018. However, his dismissal in late April 2019 adds further uncertainty to the timing of oil and gas reform, IEA adds.

Figure 71: Gas Production and Uses in Algeria, 2010–2018



Source: IEA

Iran

Based on IEA's data, Iranian gas production is expected to grow at an annual average rate of 1.8% by 2024. Most of the additional volumes are anticipated to meet domestic demand requirements, as Iran's gas consumption is growing, primarily driven by industry and power generation. Preliminary data suggest that Iranian gas production rose by approximately 3% in 2018 with the development of the South Pars field. According to the Ministry of Energy, the supergiant field accounted for over 70% of total gas volumes produced in the first 10 months of the fiscal year 2018/19 (March 2018–January 2019), up from an estimated 40% in 2012.

The country aims to boost its oil and gas industry with $200 billion of investment, of which $130 billion is destined for the upstream sector by 2021. Foreign investment contracts were awarded to Total and CNPC ($5 billion divided into Total 50.1%, CNPC 30% and Petropars 19.9%) and Russian state-owned Zarubezhneft ($0.7 billion) under the terms of Iran's new generation of upstream contract, the Iran Petroleum Contract. However, with the re-introduction of US sanctions against Iran in 2018, Total left the project in August and CNPC has allegedly halted its investment in November 2018.

Iran nevertheless continued the development of South Pars in 2018, with the installation of a second offshore platform at the field's Phase 14, increasing its production capacity by an additional 14 mcm/d (or 5 bcm/y). In March 2019, four new phases of South Pars (13, 22, 23 and 24) were inaugurated. Total investment made in these megaprojects is estimated at about $11 billion and will add production capacity of 110 mcm/d (or 40 bcm/y). In the medium term, South Pars is expected to remain the backbone of Iranian gas supply, with the Ministry of Energy foreseeing additional growth of 25% in its output by the end of 2020/21 financial year.

Azerbaijan

Azerbaijan's commercial gas production increased by 5.5% to 19 bcm in 2018 from 18 bcm in 2017, primarily driven by exports, which rose by around 10%, based on data provided by IEA's 2019 Gas Report. IEA's preliminary data indicate that commercial gas output rose by 25.9% y-o-y in January/February 2019, anticipating Azeri gas production to increase at an average annual rate of 7.3% by 2024, primarily driven by higher exports to Europe.

One of the main gas-producing assets is the Shah Deniz field, whose current Phase I was commissioned in 2006 and which has a capacity of 10 bcm/y. Shah Deniz's Phase II expansion started operations in July 2018, with first commercial deliveries to Turkey resulting in a 15% (or 1 bcm) y-o-y increase in Azeri gas delivered to Turkey in 2018. Shah Deniz Phase II will ramp up to its production capacity of 16 bcm/y by 2021/22, with approximately 6 bcm/y earmarked for Turkey via the Trans-Anatolian Pipeline (TANAP) (commissioned in June 2018) and further west to Europe via the Trans-Adriatic Pipeline (TAP) export system. Most of the additional Azeri gas supply is expected to come from the ramp-up of Shah Deniz Phase II, according to IEA.

Future gas production prospects include the Umid field, discovered in 2010 with estimated reserves of 200 bcm of gas and 30 million tonnes of condensate. According to SOCAR, Azerbaijan's national oil company, Umid could produce between 2 bcm/y and 3 bcm/y once developed. Absheron, another discovery made in 2011, has reserves estimated at 320 bcm. Total, which has a stake of 50% in the field, said in September 2018 that production could start in the third quarter of 2020 with a volume of 1.5 bcm/y, to be ramped up to 4 bcm/y in the second stage. Another promising area is the Shafag-Asiman field, which contains an estimated 1.2 tcm of gas and 240 million tonnes of condensate. BP and SOCAR could start first exploratory drillings in 2019; however, first gas production is not expected before 2030, IEA adds.

Other Caspian

Turkmenistan is set to remain the largest gas producer in the Caspian region, with an annual output of almost 70 bcm. IEA's preliminary data suggest that domestic gas production rose by 0.5% in 2018. Turkmen gas production is expected to grow at an average annual rate of 4.9% by 2024, driven both by rising domestic consumption and by increasing exports. The Galkynish supergiant field remains the largest source of additional supply. In 2016, the Turkmen Oil and Gas Ministry stated that total output from the field could reach 95 bcm/y once all the three stages are developed.

Uzbekistan's gas production rose by 6% to 60 bcm in 2018. Production in January and February 2019 amounted to 10.05 bcm – an increase of 4.2% y-o-y. In the medium term, IEA expects Uzbek gas output to remain stable as declining production from existing fields (e.g. the Shurtan field, which is 75% depleted) is compensated by the current ramping up of the Gissar and Kandym fields. In Kazakhstan, total gas production grew by 3.6% to a level of 54.8 bcm in 2018; however, about 40% of this gas is reinjected to increase oil output. Moreover, gas production is intimately linked to oil production in the form of associated petroleum gas. The ramp-up of the Kashagan giant field will continue to provide some support for additional gas production until the plateau is reached by 2020/21, after which Kazakh gas output is expected to stagnate.

6.2. Transit Countries and Their Role in Gas Trading Hubs

Turkey

Turkey holds a strategic role in natural gas transit through its position between the world's second-largest natural gas market, continental Europe, and the substantial natural gas reserves of the Caspian Basin and the Middle East. With the launch of the Baku-Tbilisi-Erzurum pipeline in 2007 and the subsequent launch of re-exports of natural gas to Greece, Turkey has begun to stake out its position as an energy bridge for gas supplies from the Caspian region to Europe. Nonetheless, in the long run, Turkey's need to satisfy rapidly growing domestic consumption could affect the country's position as a gas transit state.

The majority of Russian gas arrives in Turkey via the Blue Stream pipeline, although sizeable volumes also reach the large population centres in and around Istanbul via the Bulgaria-Turkey pipeline. In total, Turkey imported approximately 24 bcm of natural gas from Russia in 2018, according to Gazprom. The Turkish central pipeline network, controlled by BOTAŞ, distributed almost all of this natural gas to various consumers within the country.

For Turkey to function as a gas transit state, it must be able to import enough gas to satisfy firstly its domestic demand and any re-export commitments, as well as provide enough pipeline capacity to transport Caspian natural gas across its territory to Europe. While Turkey enjoyed considerable excess import capacity a few years ago, this excess pipeline capacity has eroded, as Turkey now uses most of its pipeline capacity to meet domestic demand. According to state pipeline company BOTAŞ, Turkish gas demand is forecast to grow to 81 bcm/year by 2030 from the current 50 bcm/year. It could potentially trade up to 100 bcm/year when large-scale investments in gas infrastructure have taken place, such as new LNG and storage facilities. Turkey could play a crucial role in the establishment of a gas trading hub in the region using its import and export pipelines and interconnectors.

Greece

The Interconnection Turkey-Greece (ITG), which was inaugurated in November 2007, the Trans Adriatic Pipeline (TAP) and the Interconnector Greece-Bulgaria (IGB) will help shape a gas corridor that will connect the Caspian and Middle East gas resources to the European markets. The selection by the Shah Deniz consortium of TAP as its preferred route into Europe, consolidates Greece’s position as an important part of the chain for the export of Caspian gas and could boost the development of further infrastructure, as well as of the market itself.

Furthermore, the recent upgrade of Revithoussa LNG terminal, in addition to the future implementation of the Alexandroupolis FSRU in Northern Greece and Motor Oil’s FSRU in the Corinth area, west of Athens, are very significant projects which could also help market development. The spare capacity, which is likely to result, could be exploited to supply gas to SE Europe or even more widely across the EU, through backhaul flows and swaps through the transit pipelines. However, this is possible only if there is free access in gas infrastructure and a fully open market is established.

If Greece succeeds in building the necessary infrastructure, such as the Alexandroupolis FSRU and the underground gas storage in the South Kavala basin, it could then emerge as an important gas player in SE Europe and, indeed, see its aspirations for becoming a regional gas hub for physical quantities come true.

Bulgaria

Bulgaria is well-positioned to become an energy hub for the Balkans and the region has a promising potential for gas infrastructure projects. In addition to the existing pipelines that already allow Bulgaria to import gas from Russia, the Trans Adriatic Pipeline (TAP) project may turn into a key source of gas supplies for Bulgaria through a connection with Greece's gas grid via IGB. The implementation of the reverse-flow gas link with Greece will achieve diversification of gas supply sources for Bulgaria. This will also provide the opportunity for receiving gas supplies through the Southern Gas Corridor, in parallel with the implementation of reverse-flow gas grid interconnections with Turkey, Romania and Serbia. The TAP-IGB system, together with potential gas supplies from the Alexandroupolis FSRU stationed in North Greece, are extremely important for achieving a diversification of gas supplies for the countries in SE Europe, with Bulgaria playing a crucial role in the formation of an inter-regional trading hub. In addition, the second leg of the Turkish Stream pipeline will go through Bulgaria, Serbia and Hungary and not through Greece, which emerges the important role of Bulgaria as a transit country.

It is worth noting that the Bulgarian gas grid operator Bulgartransgaz initiated in 2018 the expansion of the Trans Balkan Pipeline to allow for reverse flows from Turkey into Bulgaria, once the line is offline. As part of this project, it completed a 20-km extension of the Trans Balkan Pipeline in the southeast of the country at the beginning of August 2018, increasing its capacity by 1.7 bcm/y, to around 16 bcm/y. Bulgartransgaz has also launched a tender for the design, construction and commissioning of an 11-km spur that will link the Trans Balkan Pipeline's Strandja compressor station to the Turkish gas grid.

In early 2019, Bulgartransgaz organised a tender for the construction of a 480-km pipeline linking the northeastern point of Varna/Provadia to the Kirovo-Zajecar interconnection point with Serbia. At the beginning of April 2019, Bulgartransgaz announced that a consortium led by Saudi Arabia's Arkad Engineering won a tender to build the pipeline across Bulgaria. The group, which also includes a Milan-based joint venture between Arkad and Swiss-based ABB, offered to complete the project by the end of 2020 for €1.1 billion or within eight months for €1.29 billion.

Romania

Romania can play a dual role in ensuring new volumes of gas in the region. Upon the completion of gas interconnectors with Hungary and Bulgaria through BRUA, Romania will gain access to additional gas quantities from Austria (through Hungary) and from Greece (through Bulgaria) in addition to the volumes already imported from Russia. In addition, Romania can feed the region with its domestically produced gas, which may correspond to relatively small quantities, but may prove to be particularly important in the event of a gas crisis. Consequently, Romania could become a bridge between SE Europe and Central Europe and a viable transit country.

Serbia

The gas pipeline construction in Serbia will add considerable momentum to the development of the whole gas transmission system, turning the country into an important gas transit and storage centre for the region. Srbijagas and Gazprom have also agreed to build large gas storage facilities in Serbia with total capacities of up to 7 bcm that would serve as distribution centres. This will make Serbia an important energy player, able to distribute gas quantities to Bosnia and Herzegovina, Croatia, North Macedonia, Romania and Bulgaria.

The interconnection Bulgaria-Serbia, through which Serbia will be able to receive Azerbaijani gas, should be put into operation in 2022 and the construction of the missing infrastructure is a key condition for achieving energy security and competition in gas supplies for the SE European region. This 170 km interconnection will for the first time link the gas systems of Bulgaria and Serbia and will allow the transfer of between 1 and 1.8 bcm of gas annually from Bulgaria to Serbia and 0.15 bcm from Serbia to Bulgaria.

In addition, Serbia started the construction of its section of the Turkish Stream pipeline for transit of Russian natural gas to Europe. Gastrans, the company in charge of the project, secured the first part of the financing (i.e. €300 million) from its shareholders. Gazprom plans to build a branch of Turkish Stream for transit of gas to Europe from Turkey via Bulgaria, Serbia and Hungary. The project is part of the Kremlin's plans to bypass Ukraine, currently the main transit route for Russian gas to Europe and strengthen its position in the European market.

The planned 400-km stretch through Serbia will link the Serbian natural gas transmission system with those of Bulgaria and Hungary. The project on Serbian territory should be completed by December 15, 2019, while the projected technical capacity of the new pipeline is 13.88 bcm a year.

Hungary

Hungary is one of the largest gas markets in central eastern Europe and it is heavily gas import dependent. Russia has historically been the largest importer of gas into Hungary and today accounts for the majority of Hungarian imports. In June 2019, Hungary signed a new gas import deal with Russia, enough to heat homes and run the country's industry in 2020. The two countries also signed an agreement under which Russia will send in 2020 an additional gas amount of 2 bcm to Hungary via Austria. It is worth noting that from January 1, 2018 to November 28, 2018, Gazprom delivered 7.1 bcm of gas to Hungary, topping the total for 2017 (7 bcm of gas). Hungary has in recent years imported 5.5-7 bcm/year of Russian gas and has recently expanded its storage capacity to 6.3 bcm. Land-locked Hungary is eyeing new supplies from other sources, including regasified LNG from Italy, which would require a pipeline to be built from Slovenia. Romanian gas is a possibility, but Exxon Mobil and OMV have postponed a final investment decision on their giant Black Sea Neptun project amid uncertainties over terms, especially the gas price. Like the import terminals in

Lithuania and Poland, that would give Hungary more leverage in future contract negotiations with Russia.

In addition, Hungary's foreign affairs and trade minister reached an agreement with his Azeri counterpart in March 2019 to set up a working group tasked with laying the groundwork for the delivery of natural gas from Azerbaijan to Hungary from 2021. In June 2019, the governments of Hungary and Serbia signed an agreement on the construction of an interconnector between the gas networks of the two countries. The construction of the interconnector could start in the summer of 2020 and be completed by the end of 2021. The aforementioned projects will make Hungary an important regional gas transit country.

Ukraine

Ukraine is a major transit country for both oil and natural gas from Russia to the European Union, and it has significant indigenous energy potential, on both the gas and renewables fronts. However, it is also facing significant challenges when it comes to completing domestic reforms.

Gas has dominated the conversation around Ukraine for the past two decades. Gas destined for 15 out of the 28 EU member states transits through Ukraine from Russia, to the tune of 93.45 bcm in 2017. In the aftermath of Russia's annexation of Crimea in 2014, and the ongoing crisis in eastern Ukraine that followed, Ukraine made significant progress in weaning itself off Russian gas. It dramatically reduced its domestic gas consumption from more than 70 bcm per year in the mid-2000s to less than 40 bcm by 2016. This was partly a result of the circumstances, including the economic contraction and the loss of energy-intensive industries in the Donbas, and partly long-overdue policy action, such as price reform and the removal of most subsidies. From 2015 onwards, the country succeeded in tapping into reverse flows of (Russian) gas from neighboring Slovakia, Poland, and Hungary, reducing direct purchases from Russia to zero by 2016.

A core issue is the fate of Russian gas transit through Ukraine past 2019, when the current gas-transit contract with Gazprom expires. Gazprom has stated several times that the company's intention is to cease all shipments through Ukraine, and instead divert supplies through the planned Nord Stream II pipeline in the Baltic Sea - a plan subject to intense political debate in Europe, and vehement opposition by the United States - as well as the Turkish Stream pipeline already under construction under the Black Sea. If Nord Stream II is constructed (more than 75% is complete) and gas is fully or partially diverted, Ukraine would be deprived of significant transit revenue, weakening its already fragile economic and, potentially, political stability. **(54)**

Croatia

In 2018, Croatia produced 1.28 bcm of natural gas (from 16 onshore and 9 offshore fields) and consumed 2.84 bcm, while its imports stood at 1.56 bcm, based on statistical data provided by the BBSPA. Croatia has a well-established gas sector and an interconnected gas transmission system with connections to Slovenia (capacity: 1.8 bcm/y) and Hungary (2.6 bcm/y). Until very recently, Croatia elected to buy on open spot market and did not renew its long-term contract from Gazprom when it expired in 2011. However, in 2017, a new ten-year contract was signed with Gazprom for 1 bcm/y.

Although the country possesses some potentially promising natural gas reserves, their scope is yet to be determined. That said, Croatia might nevertheless play an important role when the LNG terminal planned for the island of Krk is completed. The terminal would not only make a great contribution to Croatia's supply portfolio, but if its capacity is expanded, it could help bring gas of varied origin all the way to Hungary, Slovakia, and (via reverse flow through the previously noted countries) even as far as Ukraine. In January 2019, Krk FSRU reached Final Investment Decision (FDI) to procure and operate a vessel, with a regasification capacity of 2.5 bcm/y, while it is scheduled to start commercial operations in the autumn of 2020. The total project is estimated to cost €243 million. This includes the charter cost for the FSRU which is estimated at €160 million, the terminal's infrastructure estimated at €60 million and expropriation cost amounting to €14 million. The EU has disbursed €102 million, the Croatian government will set aside €100 million (€50 million in 2019 and the same sum in 2020), while the remaining €32.6 million will be allocated by the founders of LNG Croatia - HEP and national grid Plinacro. **(55)**

Similarly, the terminal might facilitate building of the Omišalj-Casal Borsetti interconnector, which would connect the facility directly to the Italian gas grid. In any case, the terminal would make a great contribution to the Energy Community's Gas Ring project. Plans also call for the terminal to serve as an entry point to the North-South Corridor, an initiative encompassing a series of related infrastructural projects connecting countries within Central Europe. To speed up the Croatian LNG terminal project, the country's government switched plans and now aims to build a floating terminal whose construction timetable would be shorter than an onshore terminal.

The project could be supplied by companies and resources from Qatar, Algeria and the US, while Hungarian Minister of Foreign Affairs and Trade Péter Szijjártó said in June 2019 that the Hungarian government decided to make an offer to Croatia to acquire just over 25% of the terminal, conditional on the price Hungarian companies can buy gas there. He said gas cannot be contracted at the terminal at a competitive price at present, as the price offered is well over the price for which gas can be bought in Hungary. **(56)**

Slovenia

Gas supply in Slovenia is entirely dependent on imports from neighbouring countries. Since Slovenia cannot rely on its own natural gas sources, storage facilities or LNG terminals, the natural gas market is limited by the interconnections with the transmission networks of Austria (the Ceršak MRS), Croatia (the Rogatec MRS) and Italy (the Šempeter MRS). In order to meet its domestic demand for gas, Slovenia is mainly dependent on Russia (around 600 mcm/y). Ionian Adriatic Pipeline would play an important role in the diversification of gas supply routes and for enhancing the security of supply in the country, given the absence of gas storage facilities or domestic gas sources. Since a memorandum of understanding with the developers of TAP have already been signed with companies of Croatia, Bosnia and Herzegovina, Slovenia, Montenegro and Albania, there is also potential for cooperation through IAP. Although flow distribution and capacities available to Slovenia as well as other countries would depend on upgrades in the Croatian transmission system. The small size of the Slovenian market together with likely extension of the Gazprom's contract, however, suggests that it is unlikely to act as a significant anchor market for international transmission volumes through IAP.

Slovenia's natural gas market operates in market conditions and without regulative restrictions. The prices are formed on the basis of free functioning of the market, i.e. the existing electricity offer and demand. Thus, Slovenia does not have any national objectives that would aim at promotion of competitively determined gas prices. For the natural gas, Slovenia is too small for the creation of a liquid wholesale market; however, it is directly linked to the trading point in Austria and Italy. The planned pipeline with Hungary will also establish a possibility of a direct supply from the Hungarian trading point.

In order to provide insight into the potential and opportunities with regard to integration of gas markets in the vicinity of Slovenia, as well as to place them, the Energy Agency carried out a study in 2018, in which it was established that there is no need for formal additional integration of markets by models recommended by the ACER's market target model for the Slovenian market. Instead, it was recommended for Slovenia that the regulator ensures the implementation of network codes, while the Slovenian traders may use the easily accessible Austrian node also in the future. In this regard, sufficient short-term cross-border capacities at competitive prices are of key importance. Moreover, the study encourages the regulator and operator of the transmission system to implement the projects that enable diversification of gas sources. **(57)**

7. The Role of Central European Gas Hub (CEGH) As A Benchmark and Pivot for Promoting Gas Trading in SE Europe

For more than 13 years, Central European Gas Hub (CEGH), which is located in Vienna (Austria), has been a reliable fixture in the gas trading landscape. As the operator of the Virtual Trading Point (VTP), CEGH offers international gas traders a gateway for trading in the entry/exit zone of the Austrian market. In 2018, CEGH achieved a total trading volume of 659 TWh of natural gas and ranks among the most important gas hubs in Continental Europe.

The dedicated link between commercial transaction and physical settlement has always been crucial for successful trade. Through its connection to the important transit pipelines and storage systems, CEGH is the most attractive gas market in Central and Eastern Europe. The distribution station at Baumgarten (see Map 22) is the most eastern distribution node in Europe. Plus, the direct connection of storage facilities to the CEGH VTP contributes to additional flexibility and makes gas trading in Austria even more attractive.

Map 22: Baumgarten Station

Source: CEGH

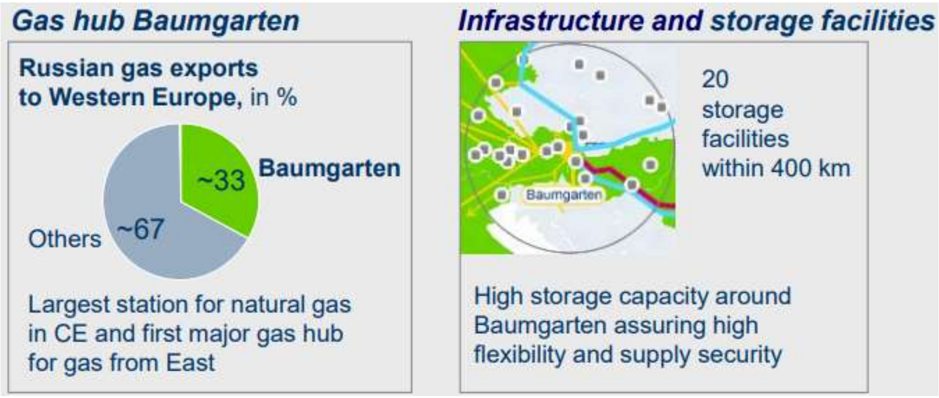
As already analysed, the shareholders of Central European Gas Hub AG are OMV Gas & Power GmbH with a stake of 65%, Wiener Boerse AG with a stake of 20% and Slovak Eustream a.s. with a stake of 15%. OMV Gas Storage GmbH operates gas storage facilities in Austria for more than 50 years. With a total working gas volume of approx. 25 TWh, OMV Gas Storage GmbH is among the leading European storage providers. In addition to the storage facilities in Austria, OMV Gas Storage Germany GmbH operates a salt cavern storage facility in Germany (Etzel) since 2012, which is connected to the Dutch and German market areas. The storage facilities of OMV Gas Storage GmbH are integrated to a storage pool and connected to the Austrian Market Area East. Registered clients have the possibility to trade on the Virtual Trading Point CEGH (VTP). **(58)**

Map 23: The Storage Facilities of OMV Gas Storage GmbH in Austria

Source: OMV

Since 2016, the Austrian and the Czech CEGH Spot and Futures contracts have been listed on the pan-European PEGAS platform under the Powernext rulebook and exchange license. This gives international traders comfortable access to comprehensive trading, clearing and settlement services on multiple markets. Traded volumes in 2017 almost tripled – a clear indicator that the cooperation was more than just a step in the right direction. In 2018, volumes continued to grow and reached an all-time high of 133 TWh.

Figure 72: Current Status of CEGH-VTP



Source: CEGH

According to EFET, CEGH has one of the highest gas hub score ratings and has developed into the most important trading hub for the CEE region, with the CEGHIX being a recognized reference price for the wider region. With its tailor-made nomination-platform as well as many additional services, CEGH actively engages with the trading community and continually develops new customer-oriented offerings.

CEGH serves as a gateway between East and West and is therefore the most interesting trading platform for SE European gas markets. In recent years, more and more traders have used CEGH as a trading hub between West and East, reflecting the needs of Eastern European countries to import gas from the West.

Taking into consideration all the aforementioned data and information as well as the fact that there is not a single gas trading hub east and south east of Vienna, CEGH could act as a pivot for organizing gas trading in this region as more and more gas flows are expected in SE Europe upon completion of major gas infrastructure projects (e.g. TAP, IGB, Alexandroupolis FSRU, etc.). In addition, if we take into account CEGH's strategic location, among important gas transit routes, with the existence of substantial gas storage facilities, we can easily understand its significance.

Is There a Need for a Benchmark Gas Hub Price in SE Europe?

In the European continental gas markets, TTF is the only pricing benchmark, while other hubs are priced as spreads with TTF prices. Although many hubs are more or less successful, only two of them, NBP and TTF, are benchmark hubs. Although the Netherlands' TTF is developed after NBP, it became the benchmark to which prices in European end-consumer contracts are pegged. TTF has developed quickly and steadily in the past few years and is considered a success story. Today, NBP is the £ benchmark for gas in the British Isles and some LNG supplies, while TTF has become the € benchmark hub for North West European gas supplies. Both are being widely used for risk management.

In SE Europe, there is neither a market mechanism to buy or sell gas in an efficient manner, nor a pricing mechanism to determine spot prices. Gas exchange is still based on long-term bilateral agreements. The lack of established market conditions hampers development and increases the potential for these markets to be coerced by dominant players. The development of regional gas trading hubs can prove critical to overcoming such inefficiencies.

A key element of such hubs is pricing indices that more readily reflect regional supply and demand fundamentals (compared to the traditional oil indexation), while facilitating both financial and physical hedging for buyers. Trading hubs can help prevent the emergence of dominant market players keen to dictate their terms or serve political interests. In fact, under the energy hub trading framework, players become more inter-dependent; hence, the former can foster cooperation, economic and political stability in a region and limit conflicts.

Regarding SE Europe, the question that needs to be addressed is whether the emerging gas trading hubs of Bulgaria, Romania, Ukraine, Greece and Turkey can build a spot gas market individually or even regionally, offering benchmark prices or their prices should be pegged to TTF, for instance. The answer to this question requires more time as the country that will be able to be first in securing relevant investments in its energy infrastructure and interconnectors will be able to become the key player in the regional gas trading zone.

On closer examination, neither TANAP nor Turkish Stream are likely to boost liquidity and support the formation of a reference price in SE Europe. Turkey will be importing Azeri gas via TANAP at a price indexed to the Russian imports and volumes will only be delivered to

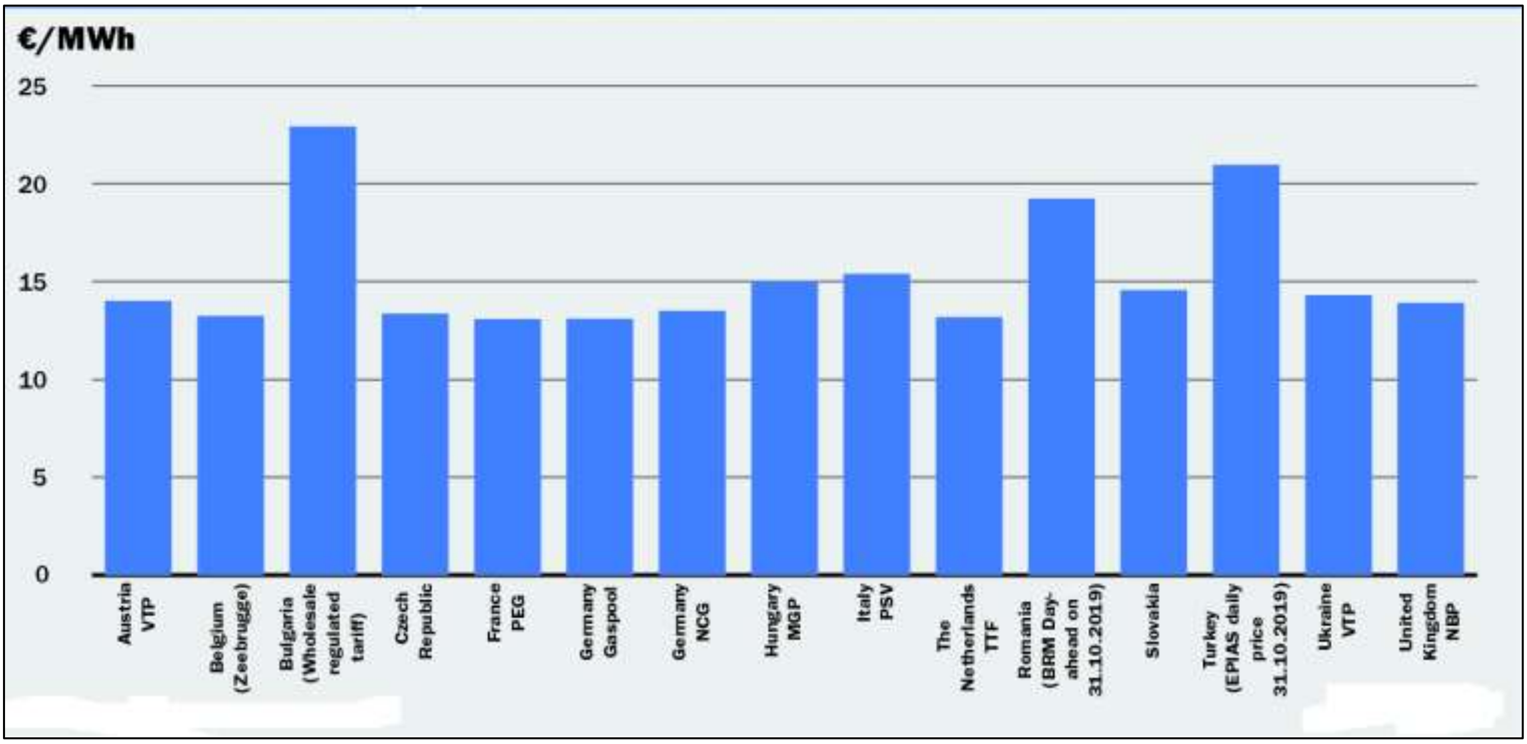
BOTAS. Since Turkish imports are oil-indexed, BOTAS has no flexibility in setting a market price, being entirely exposed to fluctuations in crude futures. It is not known how Russian gas exported via Turkish Stream will be priced, but considering the region traditionally buys at oil-indexed prices and that there are no liquid gas trading hubs in proximity, it is possible Gazprom will continue the practice in countries such as Bulgaria. Romania, which is not dependent on Russian gas due to its own resources, may start developing its own reference price, although if it continues to block cross-border trading, the benchmark would not have much regional significance.

Thanks to its active cross-border buying, Ukraine could start a border price that may act as a benchmark for the region. If Ukraine succeeds in ramping up production and reforms its domestic sector, which represents more than 60% of demand, its chances to launch a reference price would increase. However, the development of a Ukrainian reference price would depend on its commitment to continuing the reform process. Hungary, on the other hand, is one of the more promising central European countries in terms of establishing a market, looking to boost its regional connections and encourage competitive trading. The extra sources of gas that would be brought to the market, as well as the opening up of numerous bidirectional interconnections, are likely to contribute towards that. **(59)**

It is worth noting that Italy was for the first time ever a net exporter of gas in June 2018. The political will in Italy to see a strong PSV gas hub that can be a marker price for Mediterranean gas has resulted in significant changes to its market structure, especially since 2014. This has resulted in a PSV hub that progressed from “poor” to “active”; from a total traded volume of 282 TWh in 2013 to 944 TWh in 2017. Although the PSV hub is not perfect and still has further to go on the road to maturity, it could become the reference hub for southern Europe, giving the pricing signals to attract LNG and possibly become, in time, a supply route for gas into northern Europe.

From a pricing perspective, the SE European region currently carries a premium of anything between €9.00-€14.00/MWh ($2.98/MMBTu–$4.6/MMBtu) over western Europe. In Bulgaria’s and Turkey's case, this is because they operate regulated end-consumer tariffs, which reflect the price of Russian oil-indexed gas imports. As for Romania, the government reversed the liberalization process this year, capping end-consumer tariffs and introducing an import obligation despite reduced interconnection capacity with neighboring markets. The high costs paid by these countries for natural gas makes it even more imperative for them to open up their borders and allow LNG to reach their markets, while LNG companies should be attracted to sell to this premium region at a time of globally reduced profits.

Figure 73: November '19 Gas Prices Across European Markets



Sources: ICIS, BRM, EPIAS, EWRC

As already analysed, several SEE countries have expressed their interest in order to develop gas trading hubs. Although there is an increasing liquidity of some gas hubs, mainly in Northwest Europe, this does not stand for the SEE countries; thus, they also face difficulties in developing benchmark prices. Without clear benchmark prices in the region, neither LNG nor pipeline gas suppliers will have sufficient information for price discovering to allow gas to flow from the cheapest areas to the more expensive ones, neither in the medium term nor in the short term. Implementing the Gas Target Model in the EU member states of SE Europe is thus essential to provide price signals to appeal to LNG when needed. Moreover, the traditional indexation of the long-term LNG contracts to oil (derivatives) is being substituted, specifically for spot trading with hub reference price or index. This could also be used in the future for long-term contract indexation.

8. The Ascendance of Hellenic Trading Point (HTP) in the Broader Central and South East European Region

Greece imports gas from Russia, Turkey and LNG from Algeria and a number of other suppliers. Gas “imported” from Turkey to Greece almost certainly originates from Russia, Azerbaijan or from LNG, since Turkey does not produce enough gas for exports. The transmission system of Greece has three entry points: two northern entry points (i.e. Bulgaria and Turkey) and one southern entry point at the Revithoussa LNG terminal.

The commercial operation of the Gas Interconnector Greece-Bulgaria is expected to start in 2021. Currently, there is no gas interconnector to Italy, but the operation of TAP, the construction of which will be completed in 2020, will allow for more diversification in gas supply paths. Moreover, the development of the South Gas Corridor can allow Greece to become the entry point for significant gas volumes flowing from the Caspian region and towards the EU market.

Greece first introduced third-party access to the transmission grid and to the Revithoussa LNG terminal in 2010. This allowed the first non-DEPA gas imports via the Revithoussa terminal in May 2010, which opened up the Greek market. In order to diversify supply sources, Greece uses LNG imports, originally purchased under a long-term contract between the incumbent DEPA and Algeria’s Sonatrach. Consumers who want to have access to gas without contracting with DEPA need to make a bilateral contract with a supplier of LNG and book capacity in the LNG terminal separately. In parallel, suppliers and eligible customers can procure natural gas at very low cost due to DEPA’s gas electronic auction programme through which DEPA makes available at the market a certain percentage of the total quantity DEPA supplied to its customers during the year preceding the auction.

Furthermore, the Greek Regulatory Authority for Energy (RAE) has taken the first steps towards more transparency in the gas market by publishing data on a monthly basis on the weighted-average import price of natural gas into the National Natural Gas System.

It is anticipated that by 2021 sizeable gas quantities will become available via TAP. Liquidity will, therefore, be further enhanced as competition will be strengthened between local prices and European prices derived from TAP (reverse flow). As a result, the Greek gas hub will have access to European prices through TAP. The development of infrastructure, such as the planned underground gas storage facility in South Kavala, the FSRU facility in Alexandroupolis and the IGB, will facilitate the access of network users to the Greek gas market and will contribute in initiating trading activities in the Greek gas hub. It is worth noting that with the construction of the Alexandroupolis FSRU, Greece could become the first country in SE Europe to comply with the objective set by the EU for the region – that is, each EU member state in SE Europe should have at least three sources of gas to ensure security of supply. In this context, Greece’s target market zone could equal or exceed the limit of 20 bcm by 2030, as the broader geographical area of its market will, in addition to its domestic market, encompass Bulgaria, Romania and part of Turkey.

In December 2013, Greece launched the Virtual Nominations Point (VNP), following the amendment of the Greek Network Code. In April 2014, the first deliveries took place at the VNP, as wholesale customers, mainly major industrial consumers, moved the delivery point of their supply contracts to VNP.

As of July 1, 2018, Greece's National Natural Gas Transmission System has a fully operational Balancing Platform as well as a Virtual Trading Point. These developments contribute to the optimization of gas supply conditions, including prices, to the benefit of the final consumer. The activation of both facilities was preceded by the approval of a series of relevant DESFA proposals (amendments to the Greek Network Code, a new Standard Transmission Agreement, a Balancing Manual) by the Regulatory Authority for Energy (RAE), as well as the development of the necessary information systems.

Through the Balancing Platform, developed in cooperation with the Athens Exchange Group, DESFA will be able to buy and sell through auctions the quantities of gas needed, in order to balance the National Natural Gas Transmission System. The daily reference prices for the purchase and sale of gas are now formed on the basis of the transactions carried out between network users and DESFA at the Balancing Platform.

In parallel, with the activation of the Virtual Trading Point, natural gas traders not involved in physical trading are offered for the first time the possibility to operate in the Greek market, since it is now possible to get involved in natural gas transactions, irrespective of whether they have contracted capacity at entry/exit points or not.

With the 4th revision of the Greek Network Code and, in particular, the establishment of a Balancing Platform, all Interim Measures for the implementation of the European Network Code on Gas Balancing, as approved by RAE, have entered into force. At the same time, this is the first and most decisive step in the development of a functioning wholesale gas market, according to the Gas Target Model, as well as for the achievement of DESFAs' strategic objective of creating a regional gas hub.

The next step involves the operation of a Trading Platform, where anonymous transactions between gas market participants will take place. These transactions will be used to calculate the marginal prices for the purchase and sale of gas.

Hellenic Energy Exchange will act as a Trading Platform Operator for the function of gas market. EnEx Clear is designed to be the gas clearing house. The basic characteristics of Greece's gas trading hub, known as Hellenic Trading Point (HTP), would be to provide easy access to users, possibility if cross-border transactions, liquidity and absolute transparency in transactions. HTP should be benefited from being a virtual hub with entry-exit mechanism. It will act as a supply source assisting diversity and connectivity, while transparency on data and regulatory processes would directly reduce risk for market participants.

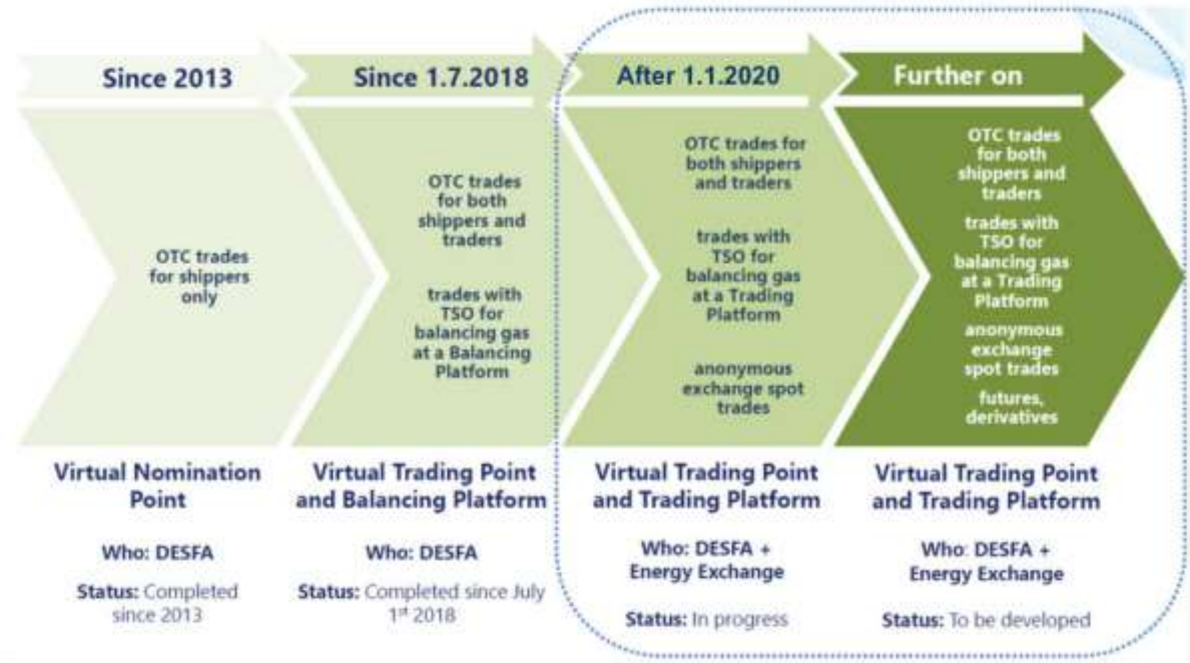
The regulatory framework is already in line with the Third Energy Package and this puts Greece a few steps ahead compared to its neighbours, in terms of market liberalization. Greece also has further advantage over its neighbouring countries, as it is part of the

Eurozone and uses the euro for all its trading. In addition, the operation of the VNP acts in favour of Greece as well, since it is the only active VNP in the region. Furthermore, the Greek stock market is governed by strict operation rules, which promote transparency and are in line with the European Union regulatory framework. On that account, the Hellenic Energy Exchange could easily offer gas futures trading, for delivery in the Greek gas hub. Hence, if by 2020, the trading platform is in full operation and Greece has set up the primary and secondary market, it will have a competitive advantage over the neighbouring countries.

On the other hand, low demand in the market due to the Greek economic crisis could restrain the development of the necessary liquidity. Delays in market liberalization of the neighbouring gas markets could also prevent traders who are active in the region from accessing the Greek gas market and vice versa. Finally, the fact that TAP will not come into operation until 2020, as well as the fact that other necessary infrastructure is not yet available, may also delay the creation of adequate liquidity in the market.

The creation of an underground storage facility is absolutely necessary, as the Greek gas market needs to be able to provide storage services to gas suppliers. Gas suppliers tend to bind to storage capacity and execute trades close to the physical location of the storage facility.

Figure 74: Timeline for the Establishment of Hellenic Trading Point in Greece



Sources: DESFA (60), IENE

The Establishment of Hellenic Energy Exchange

Aiming to enhance competition, Greece has introduced numerous stages towards the liberalization and deregulation of wholesale electricity market. The formation of Hellenic Energy Exchange (HEnEx) is one basic reform that is in line with European regulation.

Until the start of 2018, the electricity market in Greece operated through the public company LAGIE, which was responsible for undertaking the operation and monitoring he Day-Ahead market and Intra-day coupling. LAGIE's further responsibilities comprised clearing, settlement and reporting of transactions to both the Regulatory Authority for Energy (RAE) and the Agency for the Cooperation of Energy Regulators (ACER).

Aiming to modify this structure, Greek authorities in cooperation with the European Commission, have jointly formed a framework towards the implementation of Target Model guidelines. The Greek energy market framework was shaped radically in February 2017, when the Market Operator (LAGIE) and Athens Stock Exchange (ATHEX) signed a memorandum of cooperation, aiming to establish the Hellenic Energy Exchange that is designed to replace the current system of mandatory pool by the end of 2019.

The operation of the energy market is complemented by new provisions that will allow gas and environmental products to enter the platform. At the same time, the objective is to include renewables, which can facilitate to the forthcoming Power exchanges as suppliers.

Following the formation of HEnEx, a new entity was established as the market Clearing House, in order to undertake the responsibilities of Clearing, Risk Management and Settlement of the transactions.

Table 30: Detailed Timetable for the Establishment of Hellenic Energy Exchange

28/06/2019	Start Internal User Acceptance Test (UAT) for EnEx Systems
24/07/2019	EnEx Business Model and Systems Presentation to Members
10/09/2019	Start Members Registration in the EnEx Systems & Application Programming Interfaces (API) Connectivity Tests
30/09/2019	• Market Participation Kick-off Training to Members (Participants) • EnEx Test Procedure Presentation
October 2019	• Start Members (Participants) Tests • EnEx Dry Run
Q4 2019	EnEx Trading and Clearing Members Certification
March 2020	• Start EnEx/IPTO Systems Technical Readiness declaration to start Italian Borders Working Table (IBWT) and Single Day-Ahead Coupling (SDAC) Tests • Start Day-Ahead Market Coupling Tests
June 2020	Local DAM, IDM & Balancing Markets Go-Live (isolated non-coupled mode)
Q4 2020	IBWT & SDAC SC Decision for GR-IT Coupling Go-Live Window

Source: HEnEx

8.1. The Case of Turkey

Turkey has the largest energy market in the region in terms of volume and several entry points for both pipeline transmission and LNG deliveries. The country can offer gas supply diversification as it is very close to energy suppliers from the Caspian, the Middle East, as well as the Mediterranean region. The country holds a strategic role in gas transit as it is positioned between continental Europe and the significant natural gas reserves of the Caspian Basin and the Middle East. The Turkish government is in favour of creating a gas hub in Turkey; however, the country is vulnerable to supply disruptions and its pipeline capacity may not be enough to meet rising domestic demand and exports. In addition, the market is tightly controlled by BOTAŞ, which may not want to see the flexibility, competition and free market deals that a hub regime implies.

Gas consumption is expected to continue to increase in Turkey as new gas-fired power plants are put into operation. The resulting increased participation of natural gas in electricity production can significantly contribute in enhancing competition in the Turkish natural gas market. However, in Turkey, there are regulatory constraints that may impede the development of competition and the natural gas market in general, the most important of which has been the provision in Natural Gas Market Law No. 4646, which does not allow companies of the private sector to import pipeline gas directly from supplier countries that already have a supply agreement with the TSO, i.e. BOTAŞ. Draft amendments to the Law have excluded this provision.

Law No. 4646 also requires the legal unbundling of the transmission, storage and trade activities of BOTAŞ, so that an autonomous TSO is in charge of the transmission network operation. No unbundling has been put into effect to date, neither has a third-party access regime been introduced in Turkey, although draft provisions of the aforementioned Law require that all storage capacity is made available to third parties. Nevertheless, there is no equivalent requirement for LNG terminals. It is clear that a third-party access regime that allows private investments in transmission, storage and LNG terminals must be introduced at some point. Energy infrastructure and especially gas transport infrastructure needs to be further developed. However, the lack of reliable and transparent market prices and long-term transit tariff mechanisms holds up progress in energy infrastructure investments. One should also note that gas prices are to a large extent subsidized in Turkey, since BOTAS provides subsidized prices to distribution companies and wholesale consumers, such as Independent Power Producers.

In 2018, Turkey engaged in two important multinational gas pipeline projects, namely the Trans-Anatolian Natural Gas Pipeline (TANAP) and Turkish Stream. The first step was made in mid-June 2018 with the launch of TANAP, with partners like BP, BOTAŞ and the State Oil Company of the Azerbaijan Republic (SOCAR). The second step was Turkish Stream, a landmark for Turkish-Russian energy cooperation, as a ceremony for the completion of the sea part of the project was held within 2018 in Istanbul, with the participation of President Recep Tayyip Erdoğan and Russian President Vladimir Putin.

In early September 2018, the Energy Stock Exchange Istanbul (EPİAŞ) launched its spot natural gas trade system on the energy stock exchange in a bid to further liberalize the gas market. As part of Turkey's efforts to become a natural gas trading hub, EPİAŞ developed a software system to allow natural gas trading via an electronic platform.

After the successful completion of a five-month testing phase, the system officially went online. The new spot natural gas market system will determine the natural gas prices for the day-ahead market. The system price will be set by matching offers from suppliers with corresponding bids from market players to develop a supply and demand equilibrium price. Participants will be able to trade at least 1,000 cubic meters of natural gas per day.

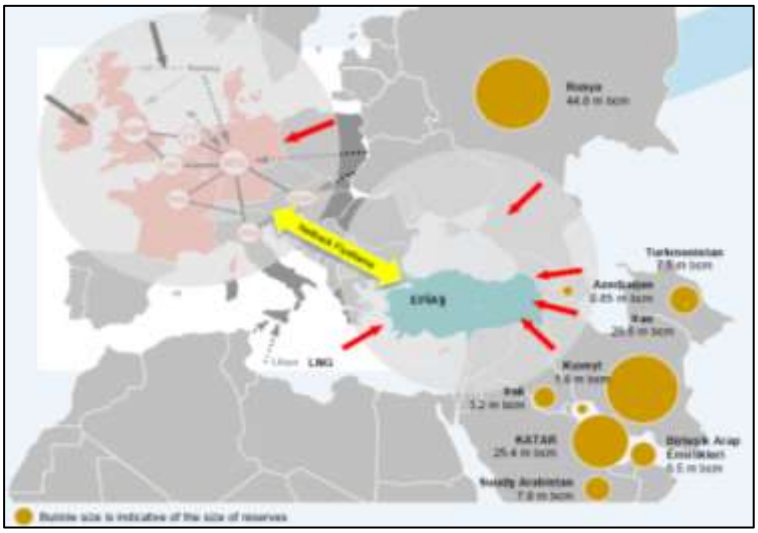
On July 27, 2018, EPİAŞ began publishing natural gas transmission data through its online transparency platform. It also started to share transport nomination, virtual trade, capacity, reserve, and actualization as well as stock amounts on a daily basis.

Turkey has maintained its efforts to ensure access to natural gas not only through pipelines but also through all forms in the global market. The long-term and spot liquid natural gas (LNG), which held a 20% share with approximately 11 bcm in the total gas import basket in 2017, is delivered to Turkey via two terminals.

There are currently two land-based LNG terminals in Turkey, namely the Marmara Ereğlisi LNG terminal with 5.9 million tonne capacity and the Egegaz LNG terminal with a capacity of 4.4 million tonnes. In addition, the two FSRUs are actively used in İzmir's Aliağa and Hatay's Dörtyol. The work on a third FSRU, which is planned to open in the Gulf of Saros, is underway. Investment agreements are underway for capacity increases in Silivri and Lake Tuz gas storage facilities. The capacity of the Lake Tuz Natural Gas Storage Facility, which was commissioned in 2017, will increase from 1.2 bcm to approximately 5.4 bcm in the medium term.

Similarly, the capacity of the Silivri facility, which can store 2.8 bcm of gas, is planned to be increased to almost 5 bcm. Thus, with a total capacity of 10 bcm in both gas storage facilities, the aim is to be able to store approximately 20% of Turkey's annual gas consumption by 2023. Meanwhile, the Organized Wholesale Natural Gas Sales Market (OTSP), which had been in progress for a long time with the intent of contributing to Turkey's goal of becoming a gas trading center, was commissioned in September 2018. While it was stated that the aim was to establish and develop a fair, sustainable and foreseeable market with OTSP, an important step was taken toward the targets of becoming a regional trading center.

Map 24: Integration of Turkey with European Gas Trading Hubs



Source: PETFORM

8.2. The Case of Romania

Romania has a long history in gas exploration and production, as it has the third largest gas reserves in the EU. As a result, it is one of the EU countries least dependent on Russian gas imports. However, Romania's hydrocarbon reserves are old and big investments in new extraction technologies are required in order to boost productivity. OMV Petrom, the largest Romanian oil company, has an ambitious investment programme of about €1 billion per year over the next few years. Exploring offshore fields is another – yet more expensive - option for Romania. Romania also holds significant shale gas reserves, with the technically recoverable reserves having been estimated at 1.61 bcm by EIA. However, as in the cases of other European countries, there were extensive protests in Romania against shale gas exploration.

There are several advantages that place Romania ahead other countries in SE Europe in terms of the establishment of a regional gas hub, such as:

- higher reserves in relation to domestic consumption, as confirmed in the Black Sea.
- the positioning of Romania between the two major European gas transport corridors, which gives the Romanian hub the opportunity to function as an arbitrage mechanism between the markets and sources of supply in the region, including through the trading of Romanian gas.
- building and upgrading existing or new infrastructure, such as the BRUA project, which will cover a two-way gas transit area that would cover the entire SE European region, including Ukraine, Moldova and the opening to Central and South Europe.

The region's liquidity aggregation, which can be achieved by developing the infrastructure for connecting the new Black Sea resources to the neighbouring markets and by realizing all the interconnections through which the Romania would acquire the role of balancing region between the northern corridors transiting Russian gas and the South Gas Corridor transiting Azeri gas. Regional cooperation for the completion of Vertical Corridor projects linking LNG terminals and new gas reserves of Eastern Mediterranean to Romania, among which we note BRUA and the Interconnector Greece-Bulgaria, are therefore absolutely vital for the Romanian hub.

However, Romania's government adopted the Emergency Ordinance no 114 or GEO 114, as it is widely known, on December 21, 2018, which introduced several tax and regulatory measures for various major industries, including the energy sector. According to the Romanian Petroleum Exploration and Production Companies Association (ROPEPCA), the competitive gas market in Romania will eventually cease to exist between April 2019 and March 2022. The obligation to sell gas at a regulated price will make competition in gas production decrease, as small independent producers will not be able to finance their operations at a capped price. The Ordinance will affect mostly the small and medium-sized producers in the gas sector. As a result, their investment in exploration and exploitation will fall by 30-50%, based on its estimates. A latest development is that under the fear of infringement and based on the European Union's recommendations, the government gave up the gas price freeze to 68 lei/MWh for industrial consumers.

In the context of the disputed GEO 114, the representatives of major oil and gas companies in Romania support that the country risks missing on the opportunity of becoming a gas hub in SE Europe. Especially, if we take into consideration that Romania needs an open market, two or three different sources of gas supply and a predictable legislation in order to become a gas hub.

On August 28, 2019, Romania's energy industry welcomed a Romanian parliamentary committee vote the day before to repeal the aforementioned controversial legislation. The Industries and Services Committee within the Romanian Chamber of Deputies voted to repeal GEO 114/2018, which was strongly condemned by companies operating in Romania as hampering new investment. This is a first step toward a return to normality and the rehabilitation of investor confidence in Romania as a destination for energy projects. Although in effect for only a few months, the measures imposed by Ordinance 114 have disrupted the functioning of the gas market, leading to an artificial increase in the unregulated price and affecting the economic viability of exploration and production projects.

Currently, there are in force gas trading obligations in Romania, which are the following: (a) 30% quota for the obligation of producers, (b) 20% quota for suppliers to enter into centralized markets transactions as buyers and (c) 30% share of suppliers to enter into transactions in centralized markets as sellers in relation to wholesale customers. Until today, there are two centralized gas trading markets, which are Romanian Electricity and Gas Market Operator (OPCOM) and Romanian Commodities Exchange (BRM). **(61)**

As announced on October 1, 2019, Romania's gas TSO Transgaz and the Central European Gas Hub signed a Cooperation Agreement on the establishment of a Romanian stock company, known as "Romanian Gas Hub", joint venture to become the operator of the Romanian Virtual Trading Point (VTP). After the implementation of the timeline for the establishment of the new company, the Romanian Gas Hub, estimated for the end of February 2020. **(62)**

8.3. The Case of Bulgaria

Bulgaria has the advantage that it operates within EU jurisdiction, while it needs desperately to diversify its gas supply sources. It should be noted that in 2018 Bulgaria relied on Russia for 99% of its gas supplies. In January 2009, Bulgaria was hit by the shock of gas supply disruption from the Russian Federation. The construction of new pipeline interconnections is envisaged by the European Commission as a means of increasing security of energy supply and this is why it has decided to fund cross-border gas pipeline projects, including the Greece-Bulgaria interconnector.

Bulgaria is expected to advance plans for a physical gas hub in Varna and for that reason Central European Gas Hub (CEGH) and Bulgaria's gas TSO Bulgartransgaz signed a Memorandum of Understanding (MoU) in Sofia on December 20, 2018, supporting the development of the Balkan Gas Hub through the exchange of information, know-how and best practices. However, considerable skepticism has been expressed by the European Commission for this project in view of huge costs involved (about €3.0 billion) and the fact that Bulgaria may opt to simply send Russian gas onto Europe to earn transit fees rather than allowing it to be traded at its planned Balkan Gas Hub, cementing its almost complete dependence on Gazprom.

The European Commission has stipulated that, in addition to securing at least three different sources of gas supplies for this project, Bulgaria needs to become a gas trader and not merely serve as a gas transit country. Given that there would be more gas volumes coming to Bulgaria from Azerbaijan, the Eastern Mediterranean or LNG, sufficient gas storage capacity will become crucial. This means that Bulgaria needs more than one gas storage facility to provide sufficient security of gas supplies that will complement the Balkan Gas Hub and make its functioning more stable. At the same time, Sofia should speed up the process of gas market liberalization and state-owned gas companies' privatization, allow access of third parties to major pipelines, and permit private companies to operate gas storage facilities in order to attract investors for this project.

In addition, it is worth noting that Gazprom's Chief Executive Officer Mr. Alexei Miller announced on March 4, 2019 that the company does not plan to participate in the Balkan Gas Hub project. Russia does not want Bulgaria to be able to mix and resell gas through an EU-backed trading platform. As a result, it will be hard for Bulgaria's government to expect either regulatory exemptions or financial aid from the European Commission, apart from the EU funding of about €1 million that has been allocated in 2017 for a technical feasibility study of the Balkan gas hub.

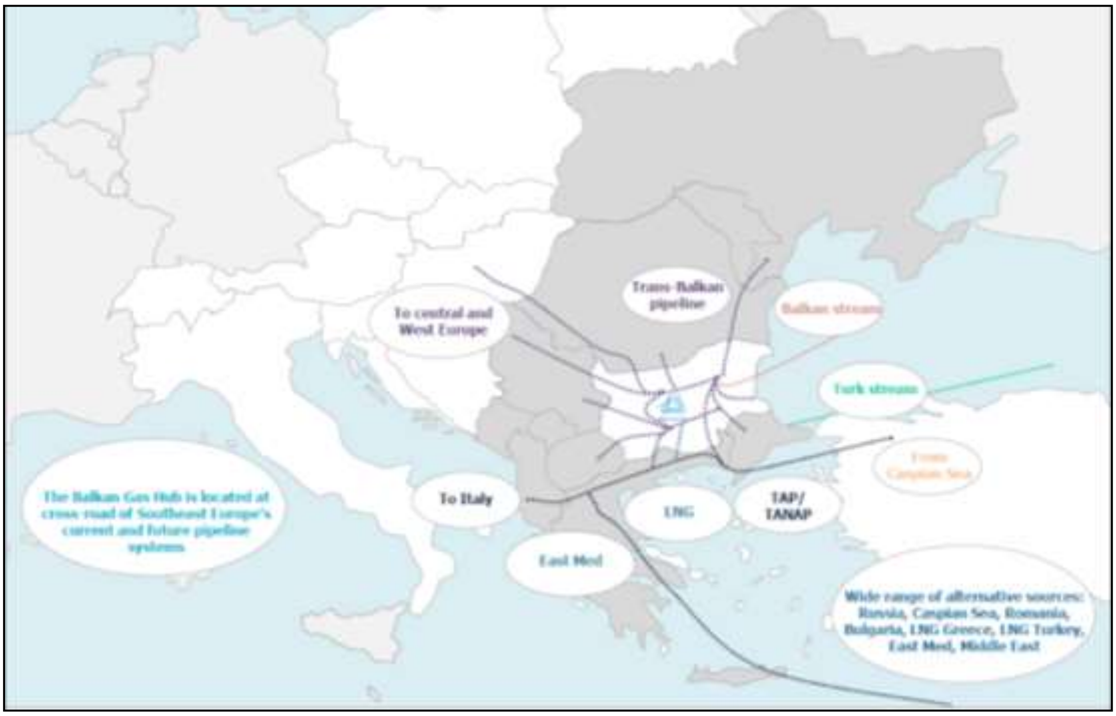
The new international pipelines coming to the Balkans, particularly the strategic South Gas Corridor, and the potential increase of LNG deliveries to Greece offer Bulgaria the chance to become a dynamic actor on the regional gas market. Sofia needs to carefully consider which options would increase its own security of supply and also contribute to European energy security.

In this respect, priority must be given to diversifying gas sources and not only gas routes. Undoubtedly, new gas supplies from the Caspian Sea and LNG from the Middle East, North Africa or as far as the United States would diversify the sources of supply to the Eastern European market, while Turkish Stream would only provide the same Russian gas that the region heavily depends on. This is an important strategic decision Bulgaria needs to make and invest as much effort in building the Interconnector Greece-Bulgaria and the Interconnector Turkey-Bulgaria (ITB). The interconnector project with Turkey is listed among the EU's projects of common interest (PCI), consisting of a 77 km-long gas pipeline (75 km on Bulgarian territory and 2 km on Turkish territory) to carry up to 3 bcm of Caspian natural gas a year initially. ITB has been in discussion for a while, but has not yet progressed to FID stage. Progress on this project has stalled because Turkey and Bulgaria could not agree on the exact capacity of the interconnector.

As external factors are coming into play in the shape of new pipelines, potential LNG regasification plants and regional gas networks development, Bulgaria must take determined actions on the domestic front. Gas market liberalization is long overdue. Sofia is facing an anti-trust case and a steep fine by the European Commission for suspected abuse of dominant position in the gas market by the state-owned Bulgarian Energy Holding (BEH) and its subsidiaries Bulgargaz and Bulgartransgaz. The Commission is concerned that BEH and its subsidiaries have refused to give competitors access to the gas transmission network, the Chiren gas storage facility, and reserved capacity they do not need on the main import line, the Trans-Balkan Pipeline.

The Bulgarian Energy Holding has objected to the privatization of its subsidiaries Bulgargaz and Bulgartransgaz as a matter of national interest. It has refused to restructure, allow competition, or open the domestic market to new producers and traders, new gas storage operators and new investors. By objecting to the liberalization and diversification of the Bulgarian gas market, BEH and its subsidiaries have been obstructing the implementation of key elements of the EU energy security strategy that are based on reducing dependence on Russian gas and opening the gas market to competition from private companies.

Map 25: The Balkan Gas Hub, as Envisaged by Bulgaria



Source: European Commission (63)

The dominant position of the state-owned monopolists would be threatened if private companies are involved in operating any element of the gas transmission and transit network or storage facilities in Bulgaria. But the nearing of new gas supply opportunities has brought urgency to addressing the core domestic problem. If not solved, investors would flee Bulgaria's energy sector, energy security would be in jeopardy, and the coveted Balkan Gas Hub project would remain only on paper.

8.4. The Case of Ukraine

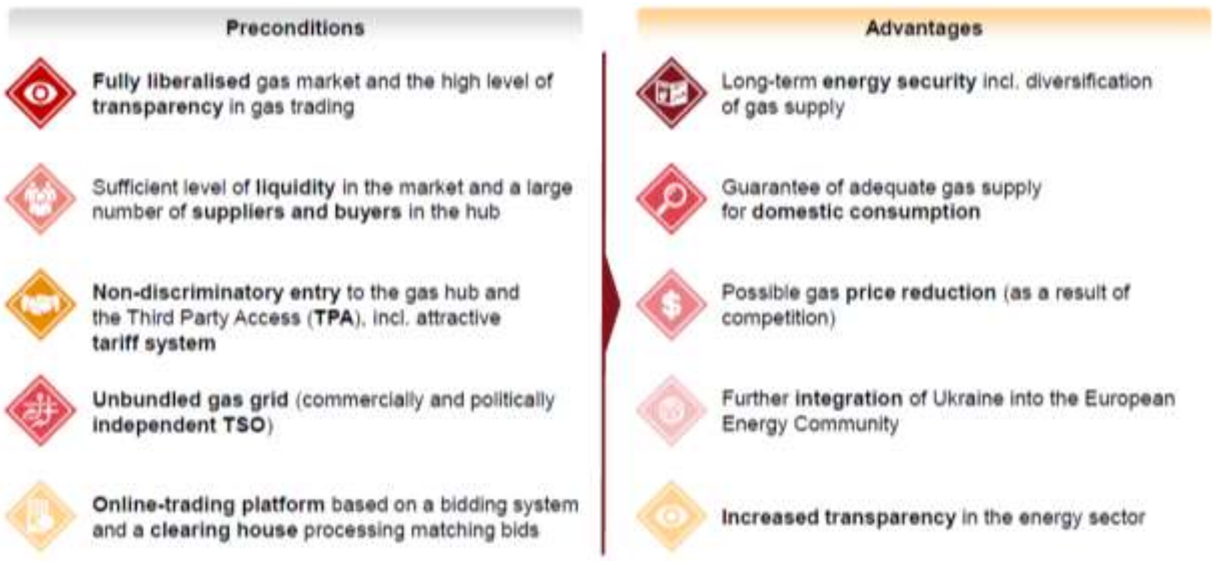
Currently, Ukraine has a storage potential of 32 bcm, distributed among 13 storage facilities. After Russia, Ukraine has the biggest working storage capacity in Europe. It is noteworthy that the bulk of this capacity (i.e. 27 bcm) is concentrated in five storage sites located in the western part of the country. This volume is twice as big as the total volume of all storage facilities located in Romania, Hungary, Slovakia and Poland (i.e. 16 bcm) and amounts to less than a third of the combined storage capacity of the EU-28m (i.e. 108 bcm). With the deployment of additional reverse flows with neighbouring EU member states, Ukraine could emerge as a natural candidate to host an eastern European gas hub.

A Ukrainian gas hub could be fuelled by gas supplies flowing from different sources. Whereas the country is a net importer of natural gas, domestic production maintains a stable level, never having fallen below the level of 17 bcm/year in the last decade. Yet the volume of domestically produced gas could increase in years to come as Ukraine holds considerable reserves of unconventional gas, mainly shale gas and coal-bed methane. By 2030, the country could produce from 30.2 bcm/year to 46.7 bcm/year of both conventional and unconventional gas.

For Ukraine, energy could become the engine behind its integration with the EU. This would be not only due to its role as a transit country for Russian gas supplies flowing into the EU, but, more importantly, to its unique storage capacity combined with a prime geographic location. Indeed, with an enhanced business climate and necessary infrastructure improvements, Ukraine could meet all the preconditions for hosting a major gas hub in the CEE region.

It is worth noting that the Ukrainian Energy Exchange (UEEX) begun electronic exchange trading in natural gas in 2017, with more than 120 companies having been accredited for gas trading. Natural gas trading on the conditions of forwards with a discount spot price is actively developing, which gives participants the possibility of a guaranteed volume of supply with binding prices to the formula. This tool can become a basis for future futures contracts in the energy market of Ukraine. Also, natural gas trades with a point of transfer in underground storage facilities and trading in import resources for non-residents are carried out.

Table 31: Required Preconditions and Potential Advantages of a Gas Trading Hub in Ukraine



Preconditions	Advantages
Fully liberalised gas market and the high level of **transparency** in gas trading	Long-term **energy security** incl. diversification of gas supply
Sufficient level of **liquidity** in the market and a large number of **suppliers and buyers** in the hub	Guarantee of adequate gas supply for **domestic consumption**
Non-discriminatory entry to the gas hub and the Third Party Access (**TPA**), incl. attractive **tariff system**	Possible **gas price reduction** (as a result of competition)
Unbundled gas grid (commercially and politically **independent TSO**)	Further **integration** of Ukraine into the European Energy Community
Online-trading platform based on a bidding system and a **clearing house** processing matching bids	**Increased transparency** in the energy sector

Source: PwC (64)

As a result of regulatory reforms, Ukraine was, for the first time, included in EFET's 2017 Gas Hub Development Study with a score of 3.5. The progress towards the establishment of a gas trading hub in Ukraine requires a number of steps to be taken at the national level, as shown in Figure 75.

Figure 75: Further Actions Needed to Progress Towards Creating a Gas Trading Hub in Ukraine

Source: PwC

In SE Europe, there are also other countries that have already expressed their interest for the establishment of a gas trading hub. For instance, Croatia took ten years to reach full liberalization of its gas market in 2017, but there is no gas hub or exchange and the limited trading that does occur is through bilateral contracts. Similarly, its neighbour Slovenia does not have a gas hub or exchange and the wholesale market is made up of bilateral trades between suppliers and distributors.

Table 32 summarises the majority of the obstacles (technical and non-technical) for the creation of regional gas trading hub(s).

Table 32: Obstacles for the Establishment of Gas Trading Hubs in SE Europe

	Obstacles
Greece	• Low demand in the gas market due to the Greek economic crisis could restrain the development of the necessary liquidity. Delays in market liberalization of the neighbouring gas markets could also prevent traders who are active in the region from accessing the Greek gas market and vice versa. • Gazprom's imminent selection regarding Turkish Stream's transit route through Bulgaria (instead of Greece) gave impetus to Sofia's plan to build its Balkan Gas Hub. • The fact that TAP will not come into operation until 2020, as well as the fact that other necessary infrastructure is not yet available, may also delay the creation of adequate liquidity in the market. • The creation of an underground storage facility is absolutely necessary, as the Greek gas market needs to be able to provide storage services to gas suppliers.
Turkey	• Regulatory constraints that may impede the development of competition and the natural gas market in general, the most important of which has been the provision in Natural Gas Market Law No. 4646, which does not allow companies of the private sector to import pipeline gas directly from supplier countries that already have a supply agreement with the TSO, i.e. BOTAŞ. Draft amendments to the Law have excluded this provision. • No unbundling has been put into effect to date, neither has a third-party access regime been introduced in Turkey, although draft provisions of the aforementioned Law require that all storage capacity is made available to third parties. • Energy infrastructure and especially gas transport infrastructure needs to be further developed. • Growing LNG-capacities in Europe will be a constraint for Turkey's path to dictate terms to the EU as regional gas hub. • Turkey is currently in need of developing hedging mechanism for gas traders against currency fluctuations since imports are paid for in foreign currency and contracts are still by and large oil-indexed.
Romania	• Romania's government adopted the Emergency Ordinance no 114 or GEO 114 on December 21, 2018, which introduced several tax and regulatory measures for various major industries, including the energy sector. According to the Romanian Petroleum Exploration and Production Companies Association (ROPEPCA), the competitive gas market in Romania will eventually cease to exist between April 2019 and March 2022. • Representatives of major oil and gas companies in Romania support that the country risks missing on the opportunity of becoming a gas hub in SE Europe. Especially, if we take into consideration that Romania needs an open market, two or three different sources of gas supply and a predictable legislation in order to become a gas hub. • Recently, a Romanian parliamentary committee vote was to repeal the aforementioned controversial legislation. • Romania's gas market will be fully liberalised on April 1, 2021, with regulated prices to be eliminated even for household consumers in order to boost gas market competition, the National Energy Regulatory Authority (ANRE) recently announced. • In October 2019, Transgaz and CEGH signed a Cooperation Agreement to establish the Romanian Gas Hub.
Bulgaria	• Balkan Gas Hub project faces the challenge of receiving approval by the EC. If Brussels gives it a green light, Turkish Stream would replace the Trans-Balkan pipeline in supplying Russian gas to the Balkans via Ukraine. In that case, the Trans-Balkan pipeline from Ukraine would be shut off and used in the reverse direction from south to north. • Another factor is the huge costs involved (about €3.0 billion) and the fact that Bulgaria may opt to simply send Russian gas onto Europe to earn transit fees rather than allowing it to be traded at its planned Balkan Gas Hub, cementing its almost complete dependence on Gazprom. • Gazprom does not plan to participate in the Balkan Gas Hub project as Russia does not want Bulgaria to be able to mix and resell gas through an EU-backed trading platform. • Limited gas interconnections and storage facilities • Sofia should speed up the process of gas market liberalization and state-owned gas companies' privatization, allow access of third parties to major pipelines, and permit private companies to operate gas storage facilities in order to attract investors for this project.
Ukraine	• Make EU public aware of the business benefits linked to gas trading hub and to convince officials that modernizing the Ukrainian Gas Transmission System is far less costly than investing in a whole new pipeline system. • A detailed study on the design of the gas hub from a technical point of view should be conducted by the government as well as a report on cost of construction of additional infrastructure and pipelines with bidirectional flow. • A Gas Hub Network Code, aligned with the Third Energy Package, should be developed. An Authority responsible for the gas hub management should be established, and its duties and responsibilities described in the Network Code. • Start negotiations with an energy exchange on gas trading, establishment of a Clearing House for the gas hub and the potential cooperation between exchange and the hub for balancing.

Source: IENE

9. Economic Implications From the Operation of A Gas Trading Hub in SE Europe – A Discussion

The setting up and operation of one or more regional gas trading hubs will undoubtedly have some economic implications for the countries involved. However, the precise impact of an operating gas trading hub on market conditions is hard to predict and even harder to quantify. The reason is the introduction of a completely new approach, together with a new and inclusive price-setting regime into a market where none existed before; other than bilateral agreements based on strict oil-indexed contracts. These bilateral arrangements still determine, to a large extent, gas prices in SE Europe (e.g. Bulgaria, Serbia, Romania, Greece and Turkey), which is predominantly supplied via pipelines. In the case of Greece and Turkey, there is a certain differentiation, since both countries satisfy about 10-20% of their needs from LNG imports, which are priced differently, although oil is still used as the basis.

On the other hand, it is relatively easy to categorize the economic parameters involved that should be taken into consideration in the ensuing discussion. These can be summarised as follows:

(a). The existing gas infrastructure and the current gas traded volumes
(b). The minimum level of new investment required in gas infrastructure work to enable the availability of adequate gas quantities to be traded through the hub
(c). The origin of gas to be supplied and to be traded through the hub, together with recent price history (i.e. average quarterly prices over the last five years)
(d). The anticipated volume of gas to be traded through the hub and the forecasted churn ratio.

In the operation of a gas trading hub, the existing infrastructure is of great importance. In the case of Greece, the National Natural Gas System (NNGS) comprises the National Natural Gas Transmission System (NNGTS) and the LNG terminal on the island of Revithoussa. The transmission system consists of one main, high-pressure pipeline 512 km long and high-pressure line branches that total 975 km in length (see Map 26). There is no strategic gas storage in Greece, and commercial stocks are only held at the site of the LNG terminal. DESFA is the owner and operator of the NNGS.

Greece's NNGTS has three entry points: two at the north and north-eastern borders (Sidirokastro and Kipi), connecting Greece with the Bulgarian and Turkish gas networks, and one in southern Greece (Agia Triada), linked to the LNG terminal. The quantities flowing through Sidirokastro represent 58% of the imported gas and the interconnector with Bulgaria has been able to operate a reverse flow of 0.3 bcm per year since May 2014; thus, enhancing the security of supply. Since 2017, the available capacity is auctioned, complying with EU regulations for cross-border trading, allowing more market players to participate and literally giving space for competition and eventually leading to market liberalization. The interconnector with Bulgaria allows for gas flows from Russia via Romania, Moldova and Ukraine.

At the borders with Turkey lies another entry point at Kipi and this Greek-Turkish interconnector brings gas mainly from the Middle East and the Caspian region into Greece. This point currently represents 15% of the imported gas or approximately 0.75 bcm and is capable of transmitting larger quantities, almost double. This will allow the activation of other companies (other than DEPA) in the cross-border trading between Greece and Turkey when agreement between EU and Turkey is eventually reached for the allocation of pipeline capacity. Today, there is only one agreement in place between BOTAS and DEPA for contracted quantities and until 2018 there was no other agreement of any other company with BOTAS. It is expected that soon this point will open for capacity auctions allowing other players to import gas through the Greek-Turkish borders. There are ongoing efforts in signing an Interconnection Agreement with Turkey.

The third entry point is the only LNG terminal in Greece, in the islet of Revithoussa near Piraeus, which now represents 27% of the imported gas quantities and it is anticipated to increase its contribution in the near future.

Map 26: Greece's National Natural Gas System

Source: DESFA

In order to discuss the economic implications from the operation of a proposed fully-fledged regional gas trading hub based in **Greece**, a number of assumptions need to be made in terms of geography, infrastructure and cost, prospective gas supplies and their origin and anticipated trading conditions. These assumptions are summarized as follows:

(1) In terms of geography, the trading will initially take place between market participants in Greece, Bulgaria, Romania and Turkey.

(2) In order for cross-border trading to evolve, the following infrastructure should be in place:

I. The Greek-Bulgarian Interconnector (IGB)

II. The TANAP-TAP pipeline system, linking Turkey, Greece, Albania and Italy

III. The gas interconnection between Greece and North Macedonia (IGNM)

IV. The underground gas storage facility in South Kavala

V. At least one floating LNG storage and gasification unit (FSRU), such as the Alexandroupolis FSRU or the Motor Oil FSRU in Agioi Theodoroi

The cumulative cost for these projects, based on company information can be estimated as follows:

Table 33: Cost of Planned Gas Infrastructure Projects

Natural Gas Project	Cost
IGB	€220 million
TANAP	€805 million (with TANAP's cost corresponding only to Turkey's European ground route)
IGNM	€50 million
TAP	€4.5 billion
South Kavala UGS	€350 million
Alexandroupolis FSRU	€380 million
Total	€6.305 million

Source: IENE

We must point out that the above cost estimate is specific to the nascent regional gas trading hubs in Greece and Turkey and is not characteristic of infrastructure costs in general for the setting up of gas trading hubs. It so happens that all the above infrastructure components are in various stages of development, with all corresponding projects slated for completion and full operation by 2022.

(3) The origin of natural gas will be as follows:

I. **For pipeline gas:** This will originate in Azerbaijan, through the TANAP-TAP system and in Russia through the Turkish Stream.

II. **For LNG:** Qatar, Nigeria, Algeria, Norway, US, East Med, etc.

(4) In view of currently available information concerning gas volumes corresponding to long-term contracts through the TANAP-TAP system, the existing capacity of the pipelines involved (i.e. IGB, IGT) and gas demand projections for 2030, one could safely assume that some 1.0 bcm of gas will become available for trading as early as 2021, rising to 2.0 and possibly to 3.0 bcm and more by 2025. In addition to that, one should take into consideration a realistic churn ratio of, let's say, 1.0 to 2.0; however, hard this may be to predict. Given the experience of European trading hubs, churn ratios may vary from 1 up to 20.

(5) Additional gas quantities for trading at the Hellenic Trading Point up to 3.0 bcm could become available from other sources such as Russian gas (via Turkish Stream), from Turkey's system (Turkish basket) and LNG until 2025.

On the basis of the aforementioned assumptions, a number of possible scenarios have been worked out for available gas trading quantities and churn ratios based on current prices in the region as follows:

Table 34: Scenarios for Trading Activity in the Regional Gas Trading Hub

Gas volume physically delivered (bcm)	Churn Ratios	Traded gas volume (bcm)	Traded value* (in million €)
1	1.5	1.5	334
	2	2	446
	2.5	2.5	557
	3	3	668
	4	4	891
	5	5	1,114
2	1.5	3	668
	2	4	892
	2.5	5	1,114
	3	6	1,336
	4	8	1,782
	5	10	2,228
3	1.5	4.5	1,002
	2	6	1,338
	2.5	7.5	1,671
	3	9	2,004
	4	12	2,673
	5	15	3,342
4	1.5	6	1,336
	2	8	1,784
	2.5	10	2,228
	3	12	2,672
	4	16	3,564
	5	20	4,456
5	1.5	7.5	1,670
	2	10	2,230
	2.5	12.5	2,785
	3	15	3,340
	4	20	4,455
	5	25	5,570

*Based on the average 2018 gas price of $245.50 per 1,000 cubic meters for Gazprom gas deliveries in SE Europe (exchange rate: US$1=€0.907620).

Source: IENE

From the data presented above, especially that concerning infrastructure investment and the anticipated volume of gas trade, it becomes clear that the setting up of the specific gas trading hub – which in the first phase will connect Greece, Bulgaria and Turkey – requires major infrastructure investment of the order of €6.3 billion[29], while it will be generating substantial financial turnovers on a yearly basis. Starting from a modest €334 million and rising to €5.6 billion, depending on available quantities and participating traders.

Of course, the actual economic and financial implications from the emergence and operation of a regional gas trading hub are far broader than the strict numbers, as shown above. The completion of the extensive gas transmission infrastructure now planned in Greece, Turkey and Bulgaria, among others, will inevitably have a positive impact on investment and industrial activity in sectors such as building construction, manufacturing, transport and storage, consulting, legal services, financial intermediation, etc. In addition,

[29] One should point out that from the above stated total investment, 88% is already committed and almost fully paid.

the sheer availability of gas in large parts of the border areas in the above countries will lead to increased peripheral gas demand from the domestic, commercial, agricultural and industrial sectors.

The operation of a proposed fully-fledged regional gas trading hub based in **Turkey** can also be feasible, as analysed in IENE's 2014 study. The development of gas infrastructure projects in Turkey, including existing, under construction and planned domestic and cross-border pipelines (e.g. Turkish Stream and the TANAP-TAP system), existing and planned underground gas storage facilities (see Table 29, page 134) and existing and planned LNG terminals and FSRUs (see Map 19, page 125) will have a positive impact on the country's economy and will facilitate increasing gas flows available for trading activities. As already analysed, the Energy Stock Exchange Istanbul (EPİAŞ[30]) launched its spot gas trade system on the energy stock exchange in September 2018, in a bid to further liberalize the gas market. This development is undoubtedly of vital importance in its attempt to emerge as a regional gas trading hub and highlights its substantial progress as Turkey and Greece are the frontrunners in establishing gas trading hubs, according to the latest EFET's 2019 Gas Hub Benchmarking Study, as shown in Figure 80.

In the case of the proposed regional gas hub, we believe it is premature to try and predict the evolution of a gas price regime after 2020-2021, once adequate gas quantities become available on a regional basis. What we can forecast though is that there is going to be strong demand for cross-border trade, as interviews with a number of local companies in all three countries reveal. Once the interconnections are in place and an effective gas exchange mechanism exists, such as the one that will be created by the proposed gas trading hub (i.e. Hellenic Trading Point), traders would be willing to buy available gas (i.e. marginal gas quantities) which will become available from main gas importers, by placing bids through the "hub" for both physical quantities and gas futures. Such trading activity will inevitably lead to the formation of a new climate of competitive prices, exerting pressure on traditional suppliers to revise their contract prices.

A lot will depend on gas volume availability, as the tendency will be for traditional suppliers to curtail the availability of extra gas quantities, so as to limit trading through the hub. In such a case and presuming that the hub has attracted a fair number of registered traders, the challenge will be for non-traditional or new suppliers to enter the picture and fill the gap by providing adequate gas quantities. This may happen from Turkey's side, where at times excess gas volumes are available within its gas grid and storage system, from the Shah Deniz consortium and its partners, who may decide to offer part of their allocated gas volumes to the open market (i.e. spot market), and from LNG suppliers through Greece's two LNG terminals (i.e. Revithoussa and one or two planned FSRUs).

The operation of the proposed regional gas trading hub is therefore predicted to have a positive effect on wholesale markets in all three countries by channeling needed gas volumes at competitive market rates. If we are to judge from the price history of selected European gas hubs, one should expect a marked differentiation from oil-indexed prices. This

[30] On July 27, 2018, EPİAŞ began publishing gas transmission data through its online transparency platform. It also started to share transport nomination, virtual trade, capacity, reserve, and actualization as well as stock amounts on a daily basis. More gas data and information are available at: https://www.epias.com.tr/en/

means that a significant portion of local gas supplies, in the range of 15% to 40% of yearly consumption for each country, could be priced at much reduced rates, which inevitably will lead to lower prices for consumers in the long term.

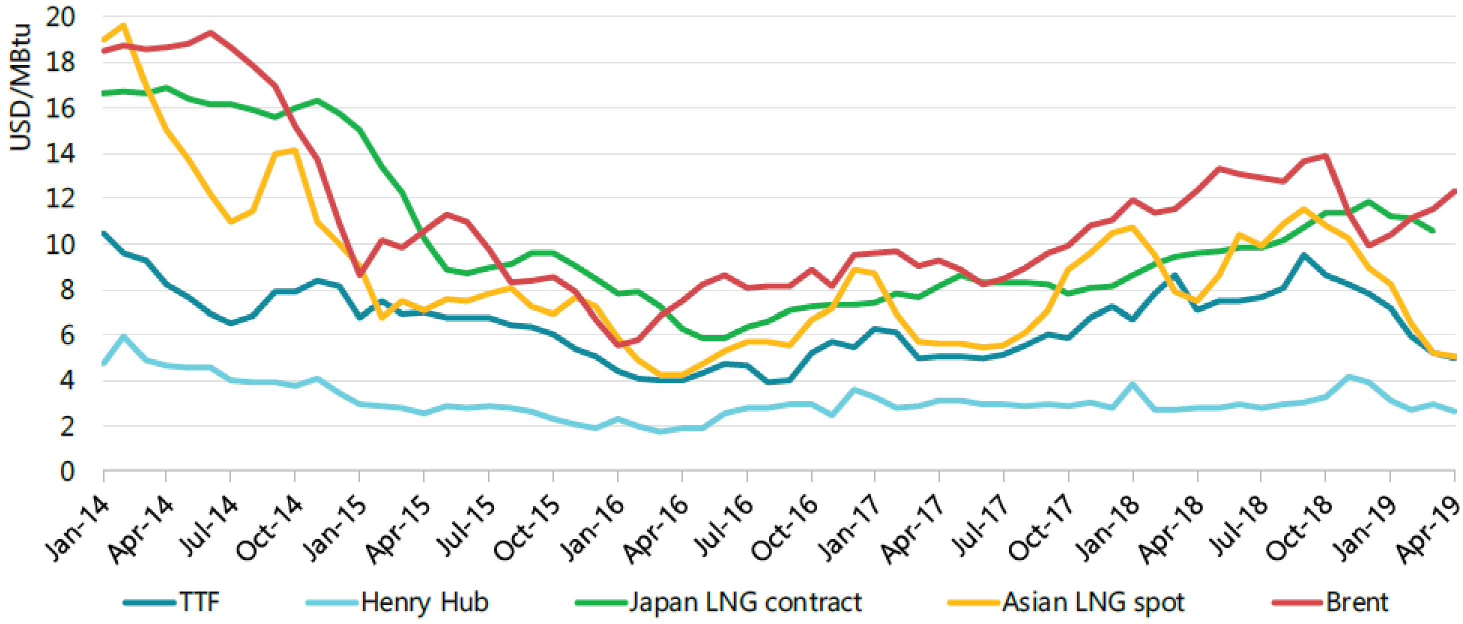
Figures 76 and 77 are the most appropriate when discussing the financial implications from the operation of a gas trading hub in our region, as they show the notable difference in prevailing prices between oil-indexed contracts and prices formed by gas-on-gas competition as well as EU gas import prices. Although it is difficult, at this stage, to predict market behaviour and its reflection on spot prices, once the above hub enters full operation, based on European hub operation experience, one could safely assume that spot prices determined through hub trading will be lower than oil-indexed ones. Of course, this is not the only positive financial implication arising from a hub operation. The attraction of sizeable tradable gas volumes and the trading activity arising from this will help to reassure markets in terms of gas availability and security of supply.

Figure 76: EU Natural Gas Import Price (US$/MMBtu), October 2015 – October 2019

Sources: World Bank, ycharts

After almost three years of decline from the end of 2013 to the first half of 2016, global gas prices increased in 2017 and 2018. Depending on the region, the 2017–2018 y-y average rate of growth varied between 6% and 38%. This has been partly driven by the strong increase in global gas demand, which grew by 4.6% – its highest growth rate since 2010, according to the IEA. Other factors contributing to the strengthening of gas prices were the rise in Brent crude prices, increasing y-y by 30% in 2018 to an average of US$71 per barrel from US$55 per barrel in 2017 (see Figure 77). This supported gas prices both directly, via oil indexation in long-term contracts, and indirectly via the arbitrage mechanisms between spot purchases and optimisation of long-term contracts. Whilst gas markets are becoming increasingly interlinked, regional price-setting dynamics retain their dominance.

Figure 77: Crude Oil and Natural Gas Monthly Average Prices, 2014–2019



Sources: IEA, Bloomberg Finance LP, ICIS

9.1. Overview of Cross-Border Transportation Tariffs: Price Levels and Tariff Network Code Effects

This section aims to analyse the specific effects of the Tariff Network Code (TAR NC). In doing so, it compares the current levels of cross-border tariffs at European Interconnector Points (IPs) and traces their projected evolution, following the implementation of the TAR NC[31], as analysed by ACER's Annual Implementation Report 2018. As a rule, transportation tariffs are added to the commodity procurement costs to establish the gas supply prices. As such, the level of cross-border tariffs can promote or hinder the supply of gas from certain origins.

Above all, transportation costs of *marginal gas supply* sources are key, because they tend to discipline price formation in wholesale markets. Tariff increases for those IPs that accommodate *marginal supplies* may lead to welfare transfers from gas customers to *non-marginal* suppliers'.

Hence, non-discriminatory and cost-reflective tariffs are core to a fair internal gas market. The gas networks' tariffs in Member States (MSs) should be set in accordance with Reference Price Methodologies (RPMs). In this respect, the TAR NC has established standards for more homogenous and transparent RPMs. The ACER reviews the proposed methodologies, examining if they do not distort cross-border gas trade and competition, while at the same time avoid cross-subsidisation between network users and are set with sufficient transparency.

[31] The new Reference Price Methodologies (RPMs), in accordance with TAR NC principles, shall enter into force for the first new tariff-period after May 2019. The transparency provisions entered into force in October 2017.

The TAR NC establishes that the same RPM should be applied to all network points in an entry-exit zone, considering specific cost drivers. However, the code also allows for some discretion in the implementation of RPMs if the aim is to pursue a better operation of the gas network. In this case, adjustments are allowed, for example, to stimulate competition. The adjustments are equalisation – i.e. removing tariff differentials to some or all points within a homogeneous group of points to reduce their variance – rescaling – i.e. adjusting all entry and/or all exit points tariffs by multiplying their values by a constant (or by adding a constant factor) - and benchmarking – i.e. adjusting the tariff at a given entry or exit point so that the resulting values meet the competitive level of references prices.

However, as adjustments may lead to discrimination issues, NRAs should exercise caution in applying them. Any such adjustment must be motivated in the NRA's RPM decisions, which shall include assessments about the impacts of the proposed RPM. Overall, RPM proposals ought to include the European perspective and to foster MSs' supply price integration. So far, the proposals assessed by the ACER related to adjustments do not show that there are important discrimination issues.

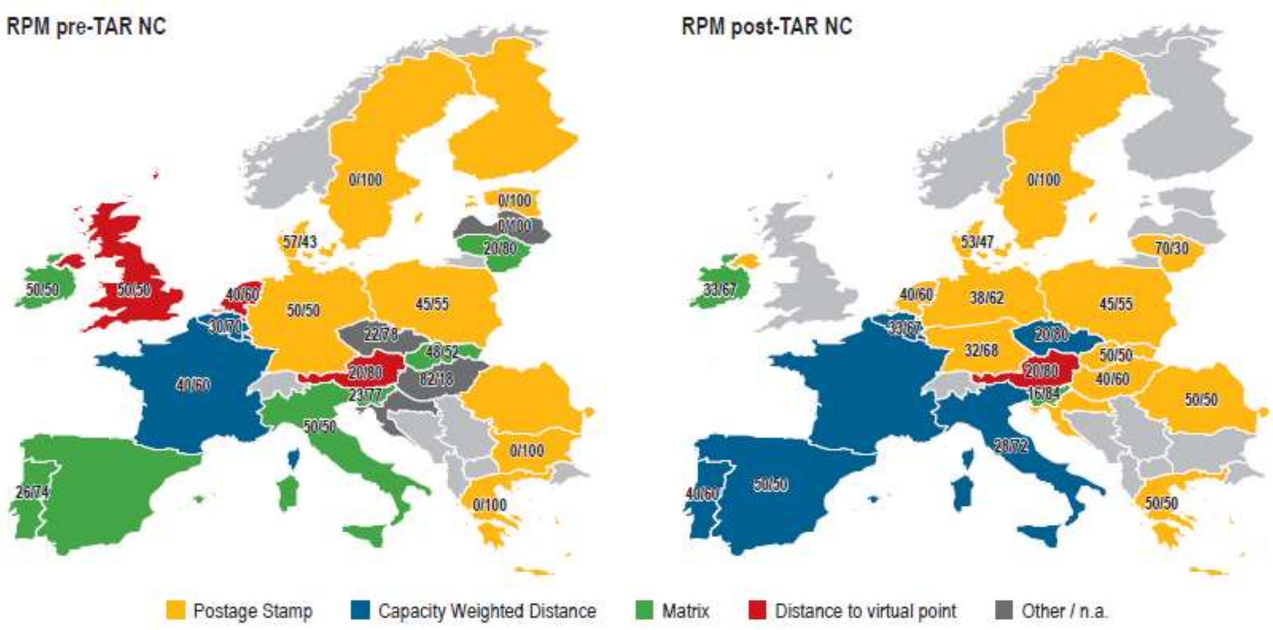
The ACER has so far reviewed the RPM proposals received from NRAs but not all NRAs have submitted them in due time[32]. Map 27 compares the reviewed RPM proposals with the methodologies currently in force. Most NRAs have opted for postage-stamp methodologies, with the justification that these provide a good trade-off between simplicity and efficient competition and are more suitable for meshed networks, where there are usually no dominant flow directions. The documents reviewed by the ACER are consultation documents, meaning that the final RPM as decided by the NRA after the consultation and the ACER's report may deviate from the one presented in the consultation document.

Another relevant element is the choice of the entry-exit split, which can considerably affect transportation costs levels[33]. The split must make use of specific cost drivers, aiming to safeguard the cost-reflectivity principle. Map 27 shows the entry-exit splits currently used and those proposed.

[32] The deadline for RPMs submission was the end of May of 2019. See the ACER analysis on the national tariff consultation documents here: https://www.acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Harmonised-transmission-tariff-structures.aspx

[33] In most MSs, the entry-exit split is an ex-ante assessment, but can also be determined ex-post as an output of the cost allocation methodology. All other factors being equal, the decision to move from a 25/75 entry-exit split to a 50/50 split would double reference prices at all entry points.

Map 27: Evolution of Tariff Methodologies and Entry/Exit Splits in EU MSs Before and After TAR NC Implementation – 2018 – Post 2019



<u>**Note:**</u> More complex RPMs, i.e. matrix, distance to virtual point aim for greater cost reflectivity. Postage stamp methodologies are simpler. For the Polish segment of the Yamal pipeline, a CWD methodology is proposed with a 52/48 E/E split. BBL and IUK set their tariffs based on a number of factors but do not apply proper RPM based on costs.

Source: ACER (2019)

NRAs have proposed a diversity of RPMs so far, with a mixture of cost drivers, parameters and adjustments, which aim to adapt the specific characteristics of national systems to the TAR NC. Some cases in point are listed in the paragraphs below. The views of the ACER for each of the points are also outlined.

- **Entry-exit splits:** 50/50 is the most common practice and is seen as the theoretical benchmark in the NC. In Austria and Slovenia, the entry-exit split has been set at around 20/80. In the Czech Republic, a 20/80 split is also set in order to minimise tariff discontinuities (i.e. it mirrors the current one). In Italy, a 28/72 value is proposed to favour the alignment of PSV prices with NWE hubs. Overall, lower entry tariffs seek to incentivise market entry and a lower hub price, whereas higher exit tariffs increase transportation costs for consumers and exporters. However, any deviation from the cost-reflectivity principles shall be duly justified, as it may entail a risk of cross-subsidisation and/or impact cross-border trade and market integration.
- **Opposite IP directions:** In close relation to the preceding paragraph, the combined effects of RPMs, entry-exit splits and cost-drivers can lead to sizeable differences in the gas transportation costs across a MS in the dominant or in the lesser used flow direction (i.e. the sum of the entry and the exit fees collected at a given border 1 to border 2 route within the MS can vary depending on the direction of the flow).

  Lower tariffs in the dominant flow direction are usually the result of higher booking levels, whereas lower tariffs in the non-dominant direction may be applied to attract flows or they may be justified by considering non-dominant flows less accountable for the route investment costs, or in fact facilitating better use of the capacity in the dominant flow direction due to the possibility of netting the flows. As an illustration, in Portugal, the RPM results in zero tariffs at the VIP Iberico exit side. This is justified by the Portuguese NRA by the historically dominant use of the interconnection to import gas from Spain, which is deemed accountable for the totality of the investment costs. On the other hand, in the Czech Republic, gas flows in the western dominant direction – i.e. the tariffs for moving gas across the Czech Republic from Lanzhot (SK) to Waidhaus (DE) is almost half of the tariffs applicable to gas flowing in the reverse and less-used eastern direction. Similarly, transporting gas across Belgium from Germany to the IUK is costlier than from the IUK to Germany.

These results are deemed valid when resulting from homogeneous cost-reflectivity considerations, consistently applied entry-exit splits and akin cost drivers (e.g. technical capacities may differ between the two flow directions). However, they may raise some issues of cross-subsidisation when not duly justified. Particularly, the setting of zero tariffs at a given IP side is in general not supported by the ACER, as it entails not applying the same RPM to all points of the network.

- **Specific points' discounts:** In Belgium, Denmark, the Czech Republic, Germany, Hungary, Italy, the Netherlands, Poland, Romania and Sweden, discounts ranging from 50% to 100% are offered at UGS entries and exits. A minimum discount is prescribed to avoid double charging for transmission to and from UGSs, which may also favour their use. In Croatia, Greece, Lithuania and Poland, discounts are also granted to the entry points from LNG facilities into the network. For example, in Poland, the discount applied at the LNG terminal is planned to reach 100% and no commodity charges will be levied. In Greece, the entire bundled access from the LNG terminal into the network is made equal to the pipeline entry tariffs. To compensate the related missing revenues, NRAs propose different scaling factors at other network points.

  In Germany, the RPM includes tariff discounts of up to 10% for conditional products, widely used by German TSOs. A biogas broad charge is announced to cover for its injection costs, whereas tariffs for the entry points to the network from biogas installations and power-to-gas are set to zero.

  Overall, there are two types of justifications for applying these discounts. First, the offered service has a lower market value than the firm product (e.g. this is the case for the conditional or interruptible capacities' discounts). Second, the service is deemed to induce positive externalities to the whole system (e.g. UGSs, LNG terminal facilities). In the latter case, the needed rescaling to compensate the missing revenues should be applied to the beneficiaries of these externalities. Overall, discounts are an accepted practice as far as the under-recovery resulting from their application is managed within the same tariff period. In the view of the

ACER, inter-temporal cross-subsidies shall be minimised with the objective of recovering transmission revenue in a timely manner.

- **Adjusted RPMs:** In Slovakia, a postage stamp RPM has been initially proposed, but has not been applied to all points of the network; instead, most IPs tariffs result from benchmarking. In Belgium, a CWD methodology is proposed, but all entry IP tariffs and all domestic exits are equalised for simplicity.

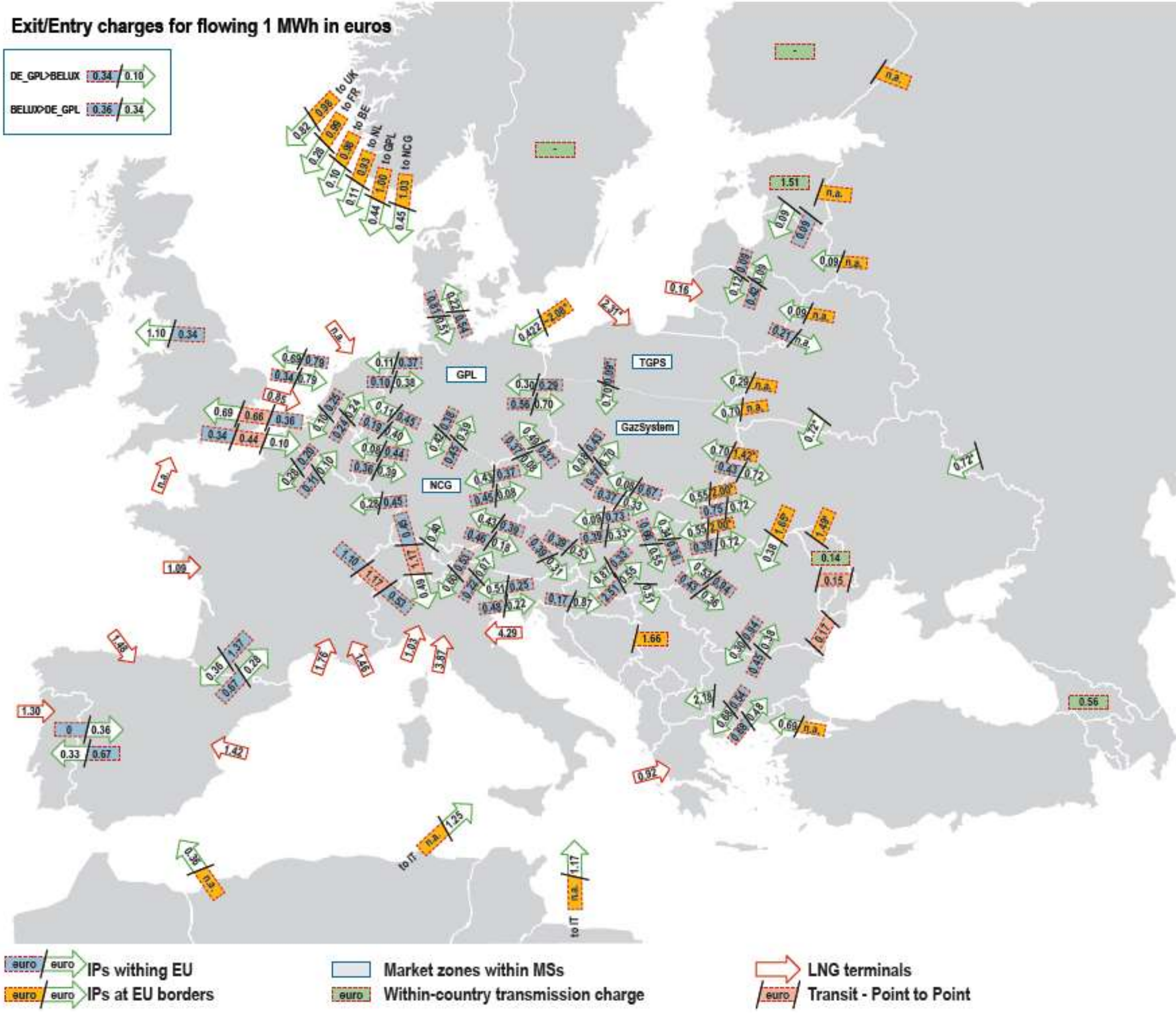
  Benchmarking and equalisation adjustments are included in the TAR NC in order to pursue a better operation of the gas systems. However, they must be duly justified, including an assessment of their effects elsewhere in the network. Arguably, the justification of benchmarking is more complex, as it entails substantiating why another route is in competition.

Additionally, the TAR NC states that for transparency reasons, all IP charges must be published on ENTSOG's Transparency Platform (TP). A simulation of all the costs incurred when flowing one GWh/day/year of gas must be made available. Map 28 shows the assessment for 2019, which also includes the system access costs of LNG and those of the Energy Community Contracting Parties (EnC CPs). Map 28 also shows the current transportation charges across distinct borders and routes. It helps to infer how tariffs could affect sourcing costs. Complementarily, Map 29 shows how tariffs could look like post 2019, reflecting proposed RPMs. Tariff levels would be also affected by the amount of allowed revenues within the new regulatory period.

Map 28 reveals that access cost of external-EU gas has been so far the lowest for Norwegian supplies into NWE MSs. In addition, the access cost through Nord Stream into Germany had been more competitive than across the Ukrainian-Slovakian gas supply route. However, this situation is likely to change after the Ukrainian tariff methodology revision, which should sizeable reduce entry, exit and storage tariffs from 2019 onwards to increase transit volumes to the EU and enhance the attractiveness of Ukraine's storage capabilities.

LNG access costs continue to be the highest. Map 28 only includes the fees for downloading, regasification and system access of LNG terminals, but the shipment costs also need to be considered. As mentioned above, in some MSs, the projected RPMs foresee discounts at the entry points from LNG facilities into the network in order to incentivise their use. Overall, the access cost borne by the distinct gas sources play their part on final gas supply price formation.

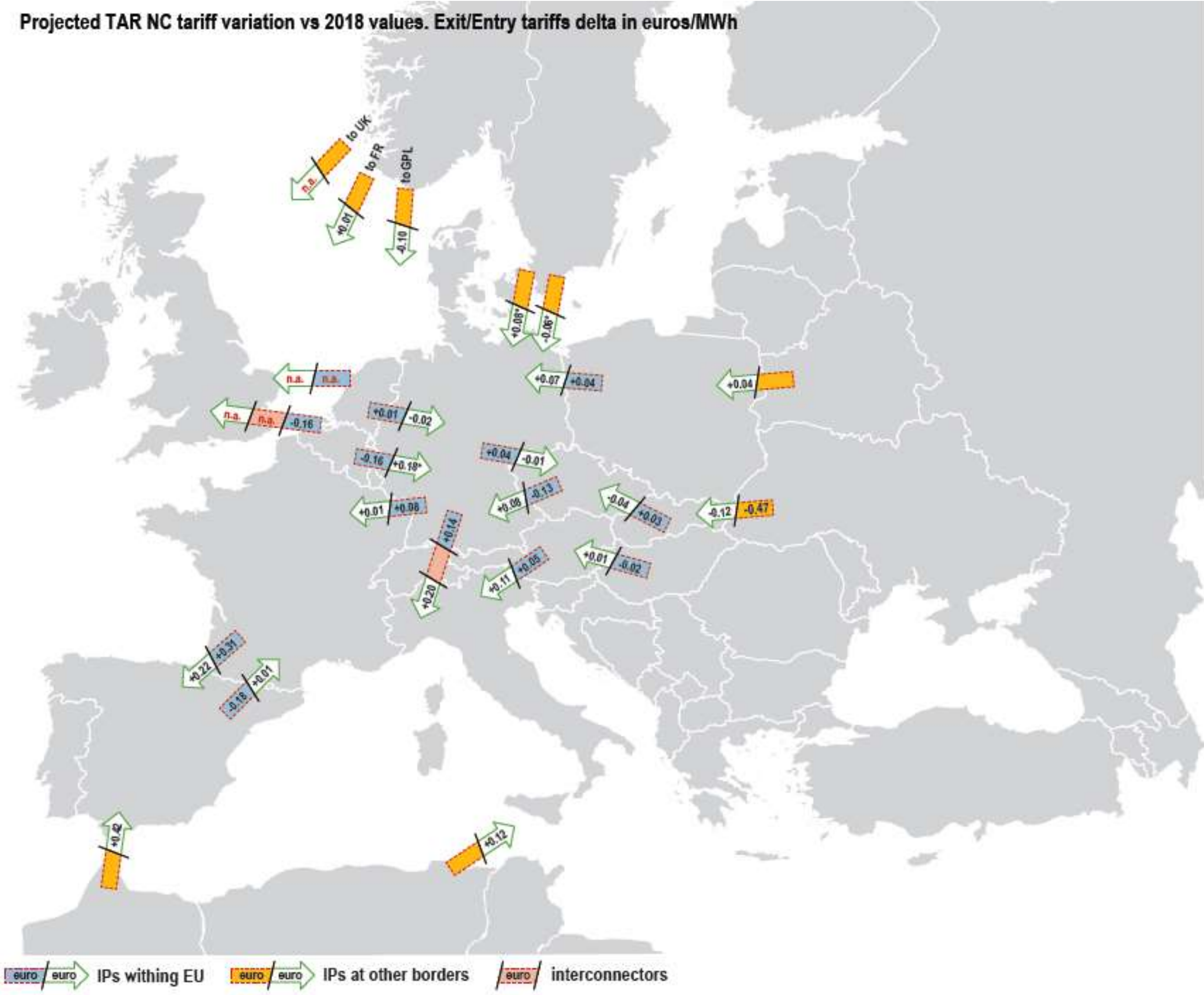
Map 28: Comparison of Average Gas Cross-Border Transportation Tariffs and LNG System Access Costs – 2019 – €/MWh



Notes: For cross-border IPs, the map displays 2019 exit/entry charges in €/MWh for the yearly product. For LNG terminals, the figure considers the costs derived from the bundled service (unloading + storage + regasification) of a 1,000 GWh LNG cargo, which regasifies the whole amount in a period of 15 days, plus the entry tariffs from the LNG terminal into the transportation network. At the Slovak IPs, only a range of tariffs can be provided since the final price is a function of the booked capacity volumes. Nord Stream tariff is an educated guess on the basis of market intelligence reports assessments. Within Poland, besides physical flow between the Yamal Pipeline (TGPS) and the Polish VTP (Gaz-System) a backhaul reverse flow is possible.

Source: ACER (2019)

Map 29: Comparison of Average Gas Cross-Border Transportation Tariffs Before and After the TAR NC Implementation for Selected Gas Supply Routes – Tariff Delta in €/MWh



Notes: Yearly capacity products considered. At those borders with more than one IP or TSO, tariff variations are assessed on a capacity weighted average; distinct IPs may see different deltas. BELUX into DE assessment refers solely to the TENP pipeline. Tariff deltas in the Greifswald IP (i.e. the German landing point of Nord Stream) differ per route: OPAL sees tariff rises (+0.06 €/MWh approx.) while NEL tariff drops (-0.08 €/MWh approx. depending on the TSO). Within German-zones tariff deltas vary per TSO. Overall, on a weighted average, GPL entries decrease by 0.10 €/MWh while NCG entries rise by 0.08 €/MWh approx. Exit tariffs see more limited variations.

Source: ACER (2019)

Some relevant cross-border tariff changes are expected to occur within the EU once the newly proposed RPMs come into force. Without being exhaustive, as Map 29 shows, the tariffs at selected German IP sides are projected to increase because of the new postage stamp methodology. This could affect gas wholesale price formation in the neighbouring markets importing gas via Germany. Cross-border exit tariffs from Austria into Italy would also increase. Some relevant tariffs changes could also occur in France, Spain or UK. However, as the concerned NRAs have not submitted the RPMs to the ACER in due time, their impacts could not be analysed in detail. These transportation cost increases could impact future price convergence levels, although this depends on other factors as well. This may be particularly sensible for the markets where the affected IPs set the hubs' marginal supply prices.

On the contrary, tariff decreases will occur in selected areas. Many of them will be driven by the competition to attract transit flows in order to secure revenues after LTCs expiration. To name a recent case, in 2017, the Hungarian exit capacity tariffs and commodity fees were reduced by 22% and 69%, respectively. In parallel, a set of LTCs that delivered gas across Austria and Slovenia into Croatia expired. The revised Hungarian tariffs made supplies across Hungary more competitive than transits via Austria-Slovenia. As a result, several Croatian shippers replaced the Slovenian supply route with bookings via Hungary. According to market analysts, the Hungarian tariff revisions are largely driven by concerns over the continuation of Ukrainian transits in the years to come.

Another example of competition can be observed with the inclusion of the BBL interconnector into the Dutch market area, which has removed the booking requirements at the Dutch side of the interconnector and has removed the prior tariffs at the Julianadorp IP. In an initial proposal, the missing IP revenues were redistributed into other points of the Dutch system. However, in line with a suggestion from the Agency, a mechanism was agreed to move some additional revenues generated by BBL back into the Dutch transmission gas system. Since a large set of LTCs expired at IUK in the summer of 2018, the (limited) gas flows from the Continent into the UK have been mostly across BBL, as will be further elaborated.

In addition to the revised RPMs, a number of opposing elements will drive the evolution of transportation tariffs in the mid-term. On the one hand, the maturity of the European transportation system has overall reduced the need for infrastructure expansion. With depreciation reducing the regulated asset base, this should reduce the pressure on future average tariff levels. On the other hand, declining demand in the mid and long-term and some forecasted reductions in bookings, once LTCs expire, may put an upward pressure on tariffs. The combined effects of these trends will have an effect on future tariff levels at EU IPs.

9.2. 2017 Gas Transmission Tariffs in SE Europe[34]

According to the EU Tariff Network Code, calculation of tariffs for annual capacity firm products shall be done by using the reference price methodology. For the calculation of reference prices, the NRA/TSO should allocate all TSO assets that are part of the TSO regulatory asset base, using the same methodology, to all entry/exit points (with the exception of non-transmission services and the revenues recovered by commodity charges). Within such a system, it is no longer possible to assign costs to specific pipelines (e.g. transit pipelines, domestic networks, etc.). Several adjustments to the reference price methodology are possible under certain circumstances, namely:

[34] Due to lack of 2018 regional data, we used 2017 data, based on a report by the Energy Community Regulatory Board (ECRB) **(65)**. This means that in some cases data changes have been recorded until now, but the provided information is for illustration purposes only.

- Benchmarking by NRAs - adjusting of tariffs to competitive levels in cases where effective pipeline-to-pipeline competition exists
- Equalization by TSOs or NRAs - the same reference price is applied to some or all points within a homogeneous group of points
- Rescaling by TSOs or NRAs - multiplying by a constant or adding/subtracting the same amount to all entry and/or exit tariffs
- Discounts for storage/LNG/infrastructure ending isolation

To comply with the requirements of the Tariff Network Code, NRAs have to calculate tariffs by using a so-called capacity weighted distance reference price methodology (CWD)[35] and compare the resulting tariffs with those stemming from the chosen reference price methodology. The CDW methodology is to be performed by applying 50/50 entry/exit splits. Entry/exit splits implemented in the SEE region in 2017 are presented in Table 35, based on data provided by the Energy Community Regulatory Board (ECRB).

Table 35: Entry/Exit Splits in SE Europe, 2017

Countries	Percentage of allowed revenue allocated to entries (%)	Percentage of allowed revenue allocated to exits (%)
Bulgaria	50	50
Croatia	70	30
North Macedonia	-	-
Greece	20	80
Romania	50	50
Serbia	57	43
Slovenia	25	75
Ukraine	30	70

Source: ECRB

In three SEE countries, the applicable entry/exit split adds up to a 50/50 share or almost so (Serbia: 57/43). Also, in three of them, the proportion allocated to exits is much higher compared to those allocated to entries; only in Croatia entry tariffs receive a higher cost allocation than exit tariffs, as shown in Table 35.

Table 36: Methodologies for Calculation of Entry/Exit Tariffs in SE Europe, 2017

Countries	Methodology
Bulgaria	Matrix
Croatia	Matrix
North Macedonia	Not applicable
Greece	CDW
Romania	-
Serbia	Other
Slovenia	Matrix
Ukraine	Other

Source: ECRB

[35] CWD assumes that the share of the allowed revenue to collect from each entry or exit point should be proportionate to its contribution to the cost of the system's capacity and to the distance between it and all exit points or all entry points. The resulting tariff would be uniform per unit of capacity and distance.

In Serbia, the capacity part of allowed revenue is allocated to different entry and exit points, according to the replacement value of parts of transmission system (pipelines, metering stations and compressor stations) which are allocated to different entry and exit points of the transmission system. That means percentage of capacity part of allowed revenue for entry point domestic production is equal to percentage of replacement value of pipelines which connect entry points from domestic gas fields with main transmission pipelines in the replacement value of whole transmission system (100%). The same principle is used to define percentage of allowed revenue allocated to all others entry and exit points.

Table 37: Allocation of Allowed Revenue/Costs to Different Entry and Exit Points in SE Europe, 2017

Countries	Of the overall TSO(s) allowed revenues (capacity and commodity charges of the tariff) of the system, which is the part covered by the exit/entry to/from the distribution system? (%)?	Of the overall TSO(s) allowed revenues (capacity and commodity charges of the tariff) of the system, which is the part covered by the exit to the final customers connected with the transmission system level? (%)	Of the overall TSO(s) allowed revenues (capacity and commodity charges of the tariff) of the system, which is the part covered by the entry/exit cross-border IPs? (%)?
Bulgaria	Data not available		
Croatia	Data not available (exits to distribution systems and exits to customers directly connected to TS are all assumed as domestic exits - and reported to HERA aggregated)	Data not available (exits to distribution systems and exits to customers directly connected to TS are all assumed as domestic exits - and reported to HERA aggregated)	29.9% (2016)
North Macedonia	There are no entry/exit tariffs, and no capacity charges. Only post stamp commodity charge		
Greece	Not available	Ex post exercise-not considered when setting the entry exit tariffs	No entry/exit cross border flows at the time when the tariffs were approved by RAE
Romania	45.49%	29.21%	0.001%
Serbia	50% (includes entry points from production and entry point from storage and exit point to storage)	11%	39%
Slovenia	29	37	34
Ukraine	currently entry-exit system is not applied for domestic points	currently entry-exit system is not applied for domestic points	100%

Note: Please note that where the shares do not add up to 100%, the rest of allowed revenue is allocated to entries/exit to and from storages and domestic production.

Source: ECRB

Similar to the allocation of allowed revenues to entry and exit points in general, allocation to specific entry and exit points - such as distribution networks, directly connected system users or cross border interconnection points - might reflect not only the costs caused to the system by different users but also national policies mainly related to protection of domestic users. To identify to a certain extent the cost-reflectivity of such allocations, information on the number of entry and exit IPs, domestic physical off-take points and final customers directly connected to the transmission network is required. Table 38 provides relevant information.

Table 38: Number of Cross-border IPs in SE Europe, 2017

Countries	Number of exit IPs	Number of entry IPs	Number of physical off-take points to DSOs	Number of physical off-take points to SSOs	Number of final customers connected to the transmission network
Bulgaria	4	3	30	1	Not available
Croatia	2	2	123	1	21
North Macedonia	0	1	2	0	55
Greece	1	1	21	0	20
Romania	6	7	881	7	228
Serbia	1	1	173	1	66
Slovenia	3	3	132	0	137
Ukraine	10	10	Not available - 44 DSOs	Not available - 12 SSOs	191

Source: ECRB

A certain correlation between the number of off-take points from the distribution system and the number of directly connected customers on one side, and their relevant revenue shares on the other, can be observed in the majority of countries for which the information on shares is available. For countries where shares are not available, a related assessment cannot be performed.

For the purpose of cost allocation assessment and capacity weighted distance price methodology, the Tariff Network Code allows for clustering of individual points. In the majority of the analyzed countries, transmission tariff methodologies include a related provision for calculating exit tariffs for distribution. The exceptions are Bulgaria and North Macedonia.

Information on individual highest and lowest entry/exit tariffs at interconnection points is presented in Table 39. It has to be noted that these are only capacity charges, so in systems where commodity charges apply, relevant tariffs will be higher than presented in the Table. On average, the highest entry and exit charges are recorded for Ukraine. Exit charges are also very high in Croatia, followed by Serbia, while high entry IP charges exist in Croatia and Greece, besides Ukraine. In Croatia, Romania and Ukraine, all entries are charged equally.

Table 39: Entry/Exit Tariffs at Cross-border IPs in SEE Region (in €/kWh/h/year), 2017

Countries	Highest entry IP capacity tariff	Lowest entry IP capacity tariff	Highest exit IP tariff	Lowest exit IP tariff
Bulgaria	-	-	-	-
Croatia	5.56	5.56	14.13	14.13
North Macedonia	-	-	-	-
Greece	4.63	4.63	4.63	4.63
Romania	3.54	3.54	3.48	3.48
Serbia	4.61	4.61	9.14	9.14
Slovenia	2.665	1.94	2.34	1.53
Ukraine	10.25	10.25	26.95	13.67

Source: ECRB

ACER recently published a few analyses/reports of the consultation documents on the gas transmission tariff structure in a number of SE European countries. Indicatively, in the case of Greece, the indicative prices for 2018 based on the CWD methodology with a single exit cluster and the proposed postage stamp methodology as calculated and presented by RAE in its consultation document are shown in Table 40. **(66)**

Table 40: Comparison of Forecasted Tariffs, According to the CWD Methodology With A Single Clustered Exit Point, to the Proposed Postage Stamp Methodology for 2018 and to the Postage Stamp Methodology, Excluding the LNG Discount (€/kWh/hr/yr)

	Sidirokastro (entry)	Kipi (entry)	Agia Triada LNG (entry)	NNGTS (exit)
CWD excluding LNG discount and rescaling*, including socialization [€/kWh/hr/yr]	5.764	9.178	3.273	7.205
Postage stamp (including LNG discount, re-scaling and socialisation). The proposed reference prices [€/kWh/hr/yr]	6.385	6.385	3.438	7.205
Absolute difference	0.621	-2.793	0.165	0
Relative difference **	11%	-30%	5%	0%
Postage stamp excluding LNG discount, re-scaling, including socialization [€/kWh/hr/yr]	5.178	5.178	5.178	7.205
Absolute difference	-0.586	-4	1.905	0
Relative difference*	-10%	-44%	58%	0%

Notes: *The CWD-based tariffs do not consider the LNG discount for Agia Triada LNG and re-scaling of Sidirokastro and Kipi. **The relative difference reported has the CWD tariffs in the denominator, whereas the relative differences reported in RAE's consultation document use the postage stamp-based tariffs in the denominator.

Source: ACER

The indicative prices for 2018, based on the CWD methodology with three exit clusters, and the proposed postage stamp methodology, as made available to the Agency by RAE, are reported in Table 41.

Table 41: Comparison of Forecasted Tariffs, According to the CWD Methodology With Three Clusters for Exit Points and the Proposed Postage Stamp Methodology for 2018 and the Postage Stamp Methodology, Excluding the LNG Discount

Entry point/Exit point	Proposed RPM with LNG discount and re-scaling [€/kWh/hr/yr]	Proposed RPM (values without LNG discount) [€/kWh/hr/yr]	CWD with 1 cluster for exit points [€/kWh/hr/yr]	CWD with 3 clusters for exit points [€/kWh/hr/yr]
Sidirokastro	6.38464	5.178232	5.764081	6.02811
Kipi	6.38464	5.178232	9.177723	9.57126
Agia Triada LNG	3.43796	5.178232	3.272784	2.85169
NNGTS single exit cluster	7.20535	7.20535	7.20535	
Cluster 1: North-East Exit				8.19135
Cluster 2: North Exit				6.55827
Cluster 3: South Exit				7.37718

Notes: All numbers in the Table are with socialisation included. Without socialisation of LNG, the tariff at domestic exit points would be 4.241 €/kWh/hr/yr for the case with a single cluster (equivalent to the proposed RPM based on postage stamp) and 5.227 €/kWh/hr/yr, 3.594 €/kWh/hr/yr and 4.413 €/kWh/hr/yr for the North-East, North and South exit clusters.

Source: ACER

In addition, regarding the transmission tariff methodology and the capacity allocation and congestion management, there are the cases of the Energy Community Contracting Parties in SE Europe, including Albania, Bosnia and Herzegovina, North Macedonia, Serbia, Ukraine, Kosovo and Montenegro, based on information provided by the Energy Community

Secretariat (67)(68). In **Albania**, the country's Energy Regulatory Authority (ERE) adopted a transmission tariff methodology for the first time in November 2017 and its practical implementation is subject to gas market development. Furthermore, ERE adopted "Rules on provision of third-party access to the transmission system and transparency in the natural gas sector", covering also congestion management procedures. However, the preparation of the relevant transmission codes is still in progress and the implementation of such rules is also subject to gas market development.

In **Bosnia and Herzegovina**, there are two main entities (i.e. Federation of Bosnia and Herzegovina and Serb Republic). Gas transmission tariffs in Federation of Bosnia and Herzegovina were never adopted, published or applied. There is also no regulatory authority with the necessary competences in place. In Serb Republic, the law requires that the transmission tariff methodology is adopted by the entity regulator, which also sets the tariffs. At present, it is implemented only for a spur of the transmission pipeline Karakaj-Zvornik, whereas for the main pipeline, Sepak-Karakaj, the procedure to adopt the tariffs is ongoing.

In terms of capacity allocation and congestion management, legislation of Federation of Bosnia and Herzegovina envisages negotiated access based on decisions of the ministry in charge of energy. Serb Republic transposed the relevant Third Package provisions on capacity allocation and congestion management. Currently, the transmission network code of Bosnia's Serb Republic company Gas Promet provides for allocation of both long- and short-term capacity on a firm and interruptible basis, whereas congestion management procedures do not envisage the re-offer of unused capacity to the primary market on a day-ahead and interruptible basis in case of contractual congestion nor the possibility for capacity trade on a secondary market. In practice, no third-party access is granted to market participants, other than to the incumbent suppliers, on any of the transmission networks.

In **North Macedonia**, the Energy Law requires that a transmission tariff methodology establishing individual setting of tariffs for entry and exit points from the system is to be developed and adopted. The regulatory authority has prepared a draft entry-exit tariff methodology. Capacity allocation rules and congestion management procedures are transposed by the new Energy Law. The Transmission Network Code of GAMA ('the Network Code') and the Market Rules issued by the regulatory authority are to be aligned with the law; thus, finally obliging the TSO to offer both firm and interruptible capacity. The Network Code envisages that capacity is sold on an annual and monthly basis. Currently, network users cannot re-sell or sublet their unused contracted capacity on the secondary market.

In **Serbia**, an entry-exit transmission tariff methodology, allowing for the setting of individual tariffs for all entries to and exits from the system, is implemented for both entry-exit zones. The transmission network codes, adopted by both Srbijagas and Yugorosgaz Transport, are generally harmonized with the requirements of Regulation (EC) 715/2009 related to capacity allocation mechanisms and congestion management procedures. TSOs offer annual, monthly and daily capacity, both firm and interruptible. Yearly capacities are offered for up to three years ahead. In case the total requested capacity exceeds the available capacity, allocation is done on a pro-rata basis. The transfer of capacity rights (subletting) is allowed for annual capacities only. In practice, neither Srbijagas nor Yugorosgaz Transport has ever performed capacity allocation, according to the codes. Srbijagas excluded the allocation of annual firm capacities at the interconnection point Horgos with Hungary from the capacity allocation invitation, without an adequate explanation. As this is the only entry interconnection point to Serbia, this directly impedes the development of the market. The codes are thus not implemented, which contributes to the foreclosure of the gas market in Serbia and breaches the acquis. The Energy Community Secretariat currently prepares infringement procedures.

In **Ukraine**, an entry-exit transmission tariff methodology is being implemented. Tariffs are available for the interconnection points with transmission systems of the neighbouring EU Member States and Moldova, for system users directly connected to the transmission network and distribution networks. The tariffs, as defined by the methodology, are still not implemented at the entry points from Russia. Utilisation of entry/exit points from production fields is currently charged at a zero rate.

The transmission network code of Ukrtransgaz provides for both long- and short-term capacity allocations. In 2017, all capacities at interconnection points and for the national market were booked on a monthly basis. According to the transmission network code, the auctioning of capacity is only foreseen at interconnection points when the overall amount of requested capacity exceeds the available capacity on a particular interconnection point. No annual capacity was allocated. Transparency of the capacity allocation process is ensured by publishing the relevant rules, allocation calendar and daily available capacities.

In case of contractual congestion, Ukrtransgaz offers unused capacity on the primary market on a day-ahead and interruptible basis. On the other side, gas distribution system operators, gas producers, direct consumers and gas storage facility operators do not have the right to re-sell their booked but unused capacities.

No tariff methodology is adopted in **Kosovo**. No secondary acts related to transmission or distribution exist. Moreover, in the absence of any gas flows in **Montenegro**, no secondary acts nor tariffs are adopted.

9.3. Relationship Between Cross-Border Transportation Tariffs and Hub Price Spreads

This Section explains the drivers that led to increased convergence of EU gas hubs' prices. It analyses in detail the relationship between cross-border tariffs and hub price spreads. It also discusses how current market trends may affect future price convergence.

The surge in EU hubs' price convergence levels over the last years has been driven by various interlinked elements. Foremost, market liberalisation and the development of gas hubs drove price convergence. But other specific factors contributed as well. The long-term over-contracting of EU midstreamers is a case in point. The mismatch between demand and historically booked capacity and surplus contracted commodity – strategic for the creation of gas markets – often turned into sunk costs for companies when demand ended up lower than forecasted. Confronted with this situation, affected companies increased inter-hub trading, placing bids around the short-run marginal costs (SRMCs) of inter-hub gas transportation[36]. Given that SRMCs tend to account for a fraction of transportation costs, spreads have tended to fall below cross-border fees.

Other market dynamics contributed to keeping hub spreads below tariffs. In some regions, convergence has been supported by suppliers paying similar prices to producers with direct physical access. For example, Norwegian producers tend to offer similar hub-price indexed contracts to NWE buyers that bear similar transportation costs to import gas to the various MSs within the region. As a result, the price difference between Norwegian supplies at each NWE hub is usually below the transportation costs for flowing gas between these hubs. In addition, price convergence is aided by Norwegian producers' delivery of their uncontracted production on the hubs, guided by NWE hubs' spot-price signals. Broad regional accessibility to LNG plays more and more a similar role, although the role and access costs for LNG show a higher variability.

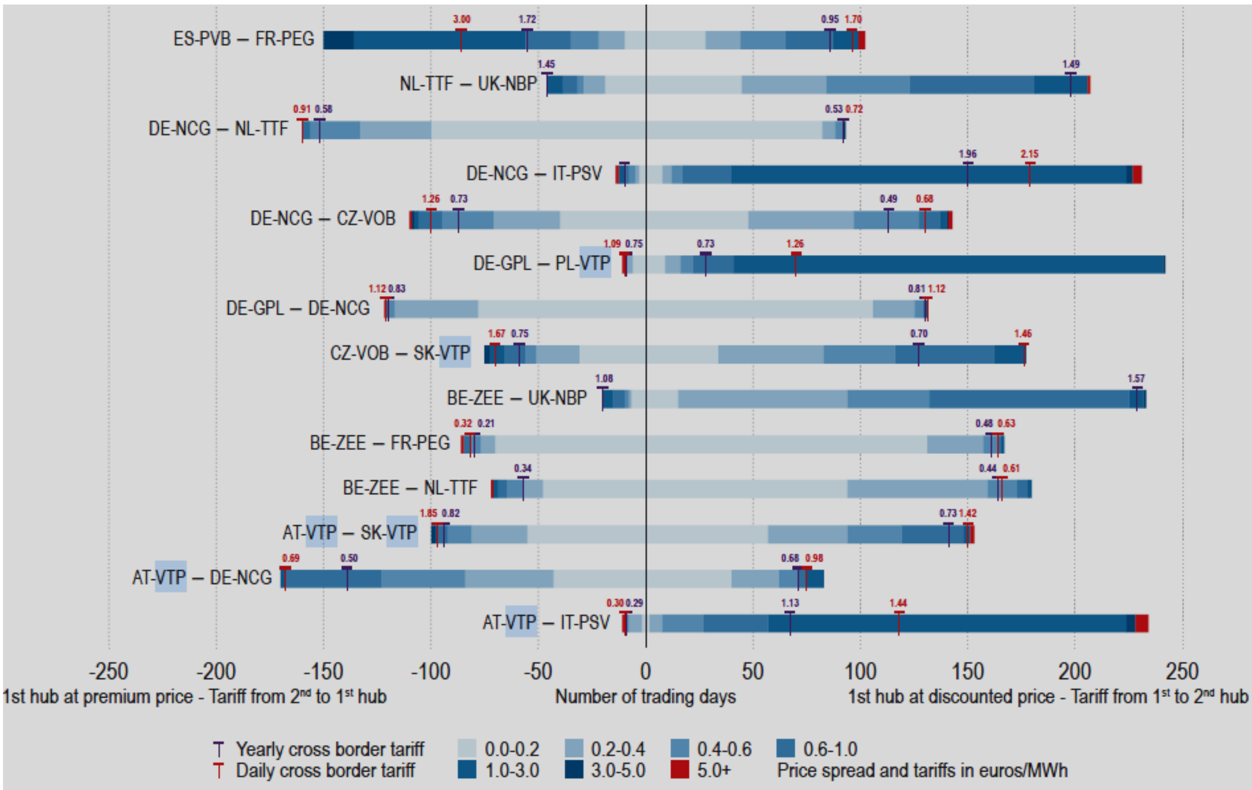
In addition, enhanced upstream supply competition has been instrumental. Gas producers may adapt their margins in order to compete in certain markets where they can or want to prioritise market share over margins. To do so, they may strategically price their supplies without fully reflecting the actual transportation costs. For reasons of proximity, Russian supplies face, for example, lower transportation costs to the Baltic or the CEE region than to NWE (e.g. for the latter gas crossing more within-EU IPs). However, Gazprom's supply prices are not necessarily higher in NWE, because Gazprom adapts its prices to the more price competitive environment of NWE, where it cannot set the price. This reinforces price convergence. In the other case, upstream suppliers' price adjustments may not be fully reflected into lower hub prices. Revised contract price conditions could have been granted to the midstreamers' purchasing the gas. However, in the absence of sound competition, they may have not been passed on to the market. Therefore, nurturing sound midstream and retail competition are key to wholesale markets' price integration.

In fact, the renegotiation of supply contracts is further pushing towards convergence of sourcing costs among many MSs. Most gas producers accept hub indexes as bilateral supply price benchmarks. This does not only occur in the EU, but also in Ukraine. Similar supply contracts' terms favour more similar hub prices. The increase in direct sales of gas producers at hubs and enhanced wholesale trading activity, including financial trading, are other contributing factors[37].

Figure 78 shows the relationship between yearly and daily transportation tariffs with spot price spreads. It helps to illustrate how different those values are across the EU hubs.

[36] e.g. transportation variable charges, trading platforms fees or other operational cost, plus expected profits for engaging in such operations. However, in selected markets, long-term contracts could also have partly hindered the capacity availability, limiting competition.
[37] i.e. the arbitrage of contracts' positions between liquid markets ahead of physical capacity bookings.

Figure 78: Day-ahead Price Convergence Levels Between EU Hub Pairs Compared to Reserve Daily and Yearly Transportation Tariffs – 2018 – €/MWh



Source: ACER (2019)

For some hub pairs – e.g. Czech VOB-Slovak VTP, Italian PSV-Austrian VTP, Spanish Mibgas PVB-French TRF (up to November TRS) – the spreads fluctuate within a larger band of the daily and yearly tariffs than for the other hub pairs.

The plausible reason might be that the long-term transportation capacity owners place, at times, bids in the higher-priced market at a price which is the result of the less expensive hub's price plus the yearly tariff, adding some margin to it within the upper limit of the daily tariff. As such, less expensive yearly bookings not only shield flow commitments, but also might aid spot prices' arbitrage. This is observed at those hubs with larger differences among the distinct capacity products' prices. For that reason, aligning tariff multipliers would stimulate cross-border spot trade and favour price convergence. The TAR NC sets a maximum multiplier of three for day-ahead tariffs.

At present, situations when spreads are above tariffs are generally observed between hub pairs with an insufficient level of competition (in one or both the hubs) and/or where networks are more isolated or not adequately connected. In fact, interconnectivity constraints can be a critical element as they can last for most of the year – exposing more structural limitations – or just occur on certain days, following particular market fundamentals.

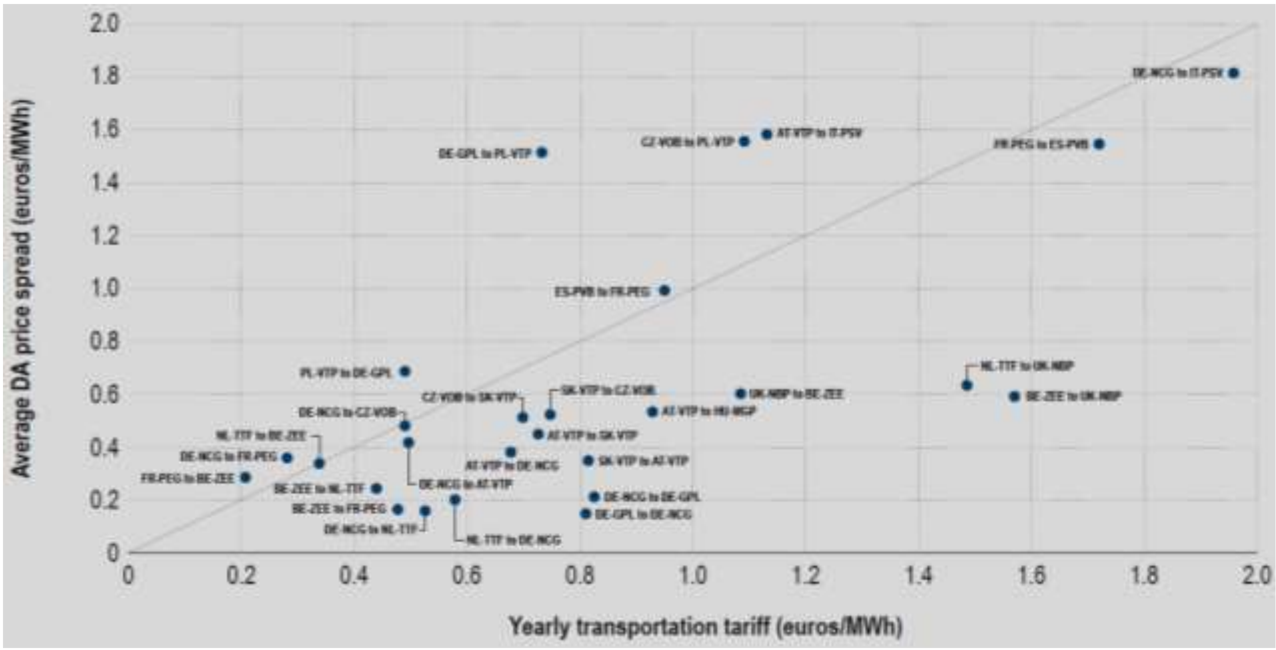
For example, the number of days when NCG-Czech VOB or ZEE-NBP spreads exceeded reserve tariffs was minor during the year, but fairly correlated to the presence of premia at capacity auctions; also during most of those days, the entered hub' price incorporated the full transportation costs across the IPs with premia, which acted as *marginal supply* source.

On the other hand, at NCG-PSV or the Austrian-Hungarian hub pairs the number of days with day-ahead spreads above daily reserve tariffs was higher. However, for many of those days there were no auction premia – in fact daily capacity was not offered every single day. More recurrent spreads above tariffs seem more the result of structural congestion. The IPs from Germany to Italy passing via Switzerland and from Austria into Hungary are labelled as congested according to the latest report from the Agency about contractual congestion in interconnection points.

The case of Poland seems of a different nature. Day-ahead spreads between the German GPL and the Polish VPGZ hub often exceed even the daily reserve tariffs, whereas the IPs connecting the MSs are moderately booked. Hub competition in Poland is constrained by a regulation that imposes demanding storage obligations on gas importers[38]. This rule led many companies to cancel their cross-border trading license in 2017 but since then five licenses for international gas trade were issued, including three for entities based abroad.

Figure 79 gives an overview of the absolute tariff levels and the price spread between EU hub pairs, in order better to identify concrete cases where spreads above tariffs were more frequent in 2018.

Figure 79: Day-ahead Price Spreads Compared to Yearly Transportation Tariffs – 2018 – €/MWh



Source: ACER (2019)

[38] The storage obligation rule stipulates that all the Polish importers must have a certain percentage of their natural gas supply either stock, in Poland or abroad.

10. Conclusions – Key Messages

The main conclusions and key messages of the present study can be summarized as follows:

1. Over the last few years, the international gas market has evolved away from long-term take-or-pay contracts that are linked to oil prices and include trade restrictions from destination clauses. Instead the market now features shorter-term contracts without destination clauses and pricing based on the supply-demand dynamics of natural gas instead of oil-linked prices. In line with these developments, the volume of spot gas trade has also significantly increased.
2. There is a definite trend in European gas markets for gas volumes to be traded through gas hubs, several of which have been established and are operating successfully in many EU countries. Already fourteen (14) such hubs are in operation and more are planned over the next few years.
3. Gas trading hubs come under two broad categories:

   i. **physical gas trading hubs**, with import and export pipelines, connections with other physical hubs mainly via interconnectors, access to storage and gas title transfer among actors trading, and

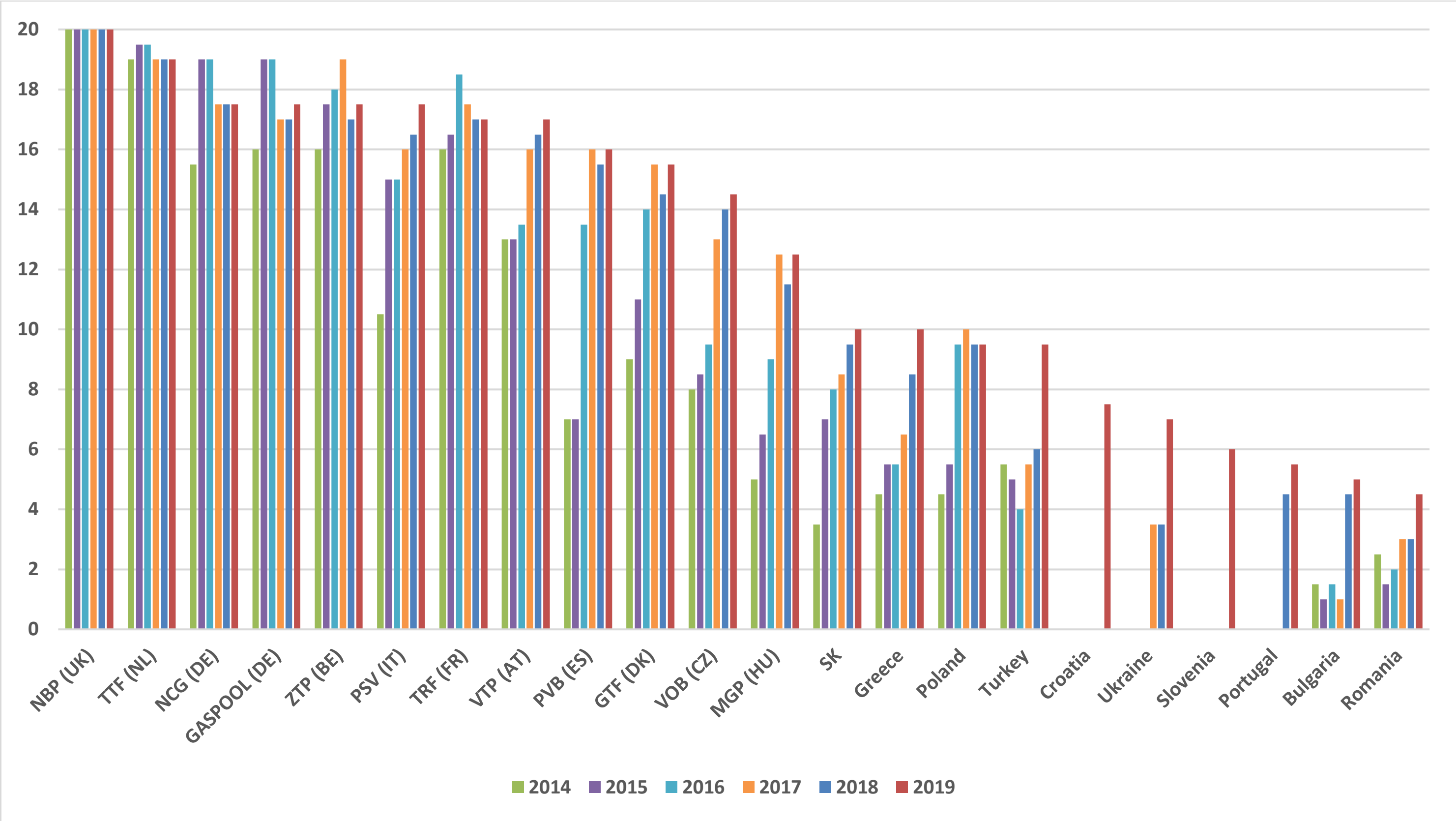
   ii. **commercial hubs with bilateral and broker-based trading**, a balancing mechanism that takes market-based price formation as a basis as well as exchange trading, futures and financial derivative transactions.

   It should be noted that gas trading hubs are not necessarily limited to strict geographical boundaries as participants tend to trade gas volumes over extended boundaries. Therefore, the concept of gas trading hubs capable of serving the need of a wider region is fast gaining ground.

4. Historical records from the operation of European gas trading hubs over the last ten years show that spot prices for gas volumes traded through the hubs are markedly lower than corresponding prices for long-term oil-indexed contracts.
5. In view of pressing European gas market needs to meet demand from a diversified supply base and planned new transit routes and interconnectors in the SE European region, coupled with increased storage capacity and new LNG terminals, available gas volumes in the region are set to increase substantially in the medium term (2021-2025).
6. On January 1, 2020, the International Maritime Organisation (IMO) will implement a new regulation for a 0.50% global sulphur cap for marine fuels, known as “IMO 2020”. Both “IMO 2020” and the European Commission’s Sulphur Directive are predicted to increase the use of LNG as a marine fuel for ships in Europe and beyond. Despite a slow uptake of LNG-fuelled vessels, it is expected that over time the LNG industry will gain from “IMO 2020” and the Sulphur Directive, with European and SE European LNG import terminals seeing increased LNG bunkering (i.e. small-scale loading) activity.

7. On the basis of the current contracted gas volumes to be transited through SE Europe by 2021-2025, it appears that market liquidity will substantially increase over the next few years with a parallel rise of gas trading opportunities.
8. The satisfaction of future gas demand in SE Europe involves various routes, including the Southern Corridor, Turkish Stream, the East Mediterranean region and LNG terminals (land-based and FSRUs). However, future gas demand increases appear to be small, meaning that gas will need to move further westwards to find market and/or competitively force itself into Turkey. But transporting gas further north to larger markets in Europe looks hard, because greater distance means greater transportation costs and therefore lower netbacks.
9. SE Europe would be significantly exposed in the case of a transit disruption through Ukraine under high demand scenarios.
10. **Today, there is not one gas trading hub (or hubs) serving the needs of the SE European region. The Vienna-based CEGH is the nearest such hub which at present serves the needs of Central European countries. Vienna's CEGH in view of its geographical position and trade volume and origin can play pivotal role in enhancing gas trading in SE Europe and also act as a benchmark (to the regional gas hub(s) to be developed).**
11. The background is already set for the planning and establishment of one or two or more gas trading hubs which will serve the needs of the broader SE European region enabling market participants in Greece, Bulgaria, Romania and Turkey to actively participate in gas trading activities.
12. Already the TSOs of the countries in the region, energy exchanges, key market players and other stakeholders are actively exploring the possibilities and prospects of establishing such gas trading hubs.
13. Setting up gas trading hubs in SE Europe should be a commercial rather than a political exercise, although governments should be fully informed of the process.
14. The EU's role through its existing legislation and Directives is crucial in ensuring suitable conditions (i.e. balancing points and virtual trading points) in the various country members of the region, which will enable free and competitive gas trading.
15. In order for one or more regional gas trading hubs to be established in the mid-term, market liquidity must increase considerably. For this to happen, a series of key gas infrastructure projects (e.g. TAP-TANAP system, IGB, South Kavala UGS, FSRUs) must be fully implemented, with construction and operation likely to converge in 2021.
16. **Already, there is a number of nascent gas trading hubs in SE Europe, which include those in Greece, Turkey, Bulgaria and Romania.** According to the EFET's Annual Scorecard 2019 **(69)**, Greece is the frontrunner in SE Europe in its attempt to establish a regional gas trading hub, which is known as Hellenic Trading Point (HTP), as shown in Figure 80.

Figure 80: EFET's 2019 Gas Hub Benchmarking Study



Source: EFET

17. As the Groningen gas field in the Netherlands is planned to be closed by 2022, this is bound to affect TTF's effectiveness as a key pricing benchmark. Hence, an opportunity arises for the emergence of new regional gas trading hubs, with CEGH being in a suitable location to take advantage of it.
18. The experience of numerous European gas trading hubs demonstrates that there are certain essential factors for gas hub development. Unbundling of vertically integration gas companies creates the necessary conditions for the emergence of market players. Market liberalization and pricing transition create the need of trade and liquidity. Hubs and the transition of gas pricing formation are interconnected. In addition, the liberalization and pricing transition requires political determination, and changes of cultures, regulations and governance practices.
19. **IENE proposes that all emerging gas trading hubs in SE Europe sign a Memorandum of Understanding (MoU) with CEGH**, supporting the development of their hubs through the exchange of information, know-how and best practices.
20. This study does not intend to promote the emergence of a specific gas trading hub in SE Europe and only attempts to shed light on the latest related developments. Inevitably, competition between gas hubs in the region will ensue and successful gas trading hubs will be able to attract business on account of their ability to provide cost-competitive and high-quality services.

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