



THE OUTLOOK FOR A NATURAL GAS TRADING HUB IN SE EUROPE

An IENE Study Project (M19)

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Coordinator: Costis Stambolis
Principal writer: Argiro Roinioti

Contributors:
Rosen Simitchiev, Bulgarian Energy Holding
Nicholas Sofianos, IENE
Gokhan Yardim, Angoragaz Import Export Wholesale Inc.
Julian Lee, Independent consultant
Pantelis Manis, Hellenic Central Securities Depository
Radamanthys Tsotsos, Hellenic Central Securities Depository

Institute of Energy for S.E. Europe (IENE)
3, Alexandrou Soutsou, 106 71 Athens, Greece
tel: 0030 210 3628457, 3640278 fax: 0030 210 3646144
web: www.iene.gr, e-mail: secretariat@iene.gr

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ABBREVIATIONS AND UNITS

ACER	Agency for the Cooperation of Energy Regulators
AIB	Association of Issuing Bodies
APX	Amsterdam Power Exchange
BBL	Balgzand Bacton (pipe)Line
bcm	billion cubic metres
CEGH	Central European Gas Hub
CEGHIX	Central European Gas Hub Index
CER	Certified emission reduction
CHP	Combined heat and power
CO ₂ -e	Carbon dioxide equivalent
CRES	Centre for Renewable Energy Sources
DOE	Department of Energy
DS Futures	Deferred settlement futures
DSO	Distribution System Operator
ECC	European Commodity Clearing
EEC	Energy Efficiency Credit
EECS	European Energy Certification System
EEPS	Energy Efficiency Portfolio Standard
EEX	European Energy Exchange
EGAS	Egyptian Natural Gas Holding Company
EGEX	European Gas Exchange
EIA	Energy Information Administration
EMCC	European Market Coupling Company
ENDEX	European Energy Derivatives Exchange
ENTSO	European Network of Transmission System Operators
EPAD	Electricity Price Area Differential
ERGEG	European Regulators Group for Electricity and Gas
ESC	Energy Saving Certificates
EUA	European Union allowance
EXAA	Energy Exchange Austria
FCA	Financial Conduct Authority (UK)
FERC	Federal Energy Regulatory Commission
FSRU	Floating storage and regasification unit
FYROM	Former Yugoslav Republic of Macedonia
GBP	German border price
GDP	Gross Domestic Product
GO	Guarantee of Origin
GPL	Gaspool Balancing Services hub
GTS	Gasunie Transport Services
GWh	Gigawatt hour
H gas	High calorific natural gas
IAP	Ionian Adriatic Pipeline
ICE	Intercontinental Exchange
IEA	International Energy Agency

	Center for Research on Energy and Environmental Economics and Policy, Università Bocconi
IEFE	
IGB	Interconnector Greece-Bulgaria
IGI	Interconnector Greece-Italy
IMF	International Monetary Fund
ISO	Independent System Operator
ITGI	Interconnector Turkey-Greece-Italy
ITO	Independent Transmission Operator
km	Kilometres
KWh	Kilowatt hour
L gas	Low calorific natural gas
LEBA	London Energy Brokers' Association
LNG	Liquefied Natural Gas
m	Metres
MAGI	Month Ahead Italian Gas Index
mcm	million cubic metres
MMbtu	Million British Thermal Units
MTF	Multilateral trading facility
NBP	National Balancing Point
NCG	Netconnect Germany
NETA	New Electricity Trading Arrangements
NRA	National Regulatory Authority
NTS	National Transmission System
NYMEX	New York Mercantile Exchange
OCM	On-the-day Commodity Market
OIES	Oxford Institute for Energy Studies
OMI	Iberian Market Operator
OTC	Over the counter
PEG	Point d'Echange de Gaz
PEGAS	Pan-European gas co-operation
PSV	Punto di Scambio Virtuale
RAE	Regulatory Authority for Energy
REC	Renewable Energy Certificate
RES	Renewable Energy Source
SAP	System Average Price
SBU	Standard bundled unit
SMBP	System Marginal Buy Price
SMSP	System Marginal Sell Price
TANAP	Trans-Anatolian Pipeline
TAP	Trans-Adriatic Pipeline
tcm	Trillion cubic metres
TOP	Take-or-pay
TPA	Third Party Access
TSO	Transmission System Operator
TTF	Title Transfer Facility
TWh	Terrawatt hours

UGS	Underground gas storage
VTP	Virtual Trading Point
ZEE	Zeebrugge gas hub
ZTP	Zeebrugge Trading Point

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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 in order to examine the conditions and prospects for establishing a regional Gas Hub for South Eastern Europe. At present, there is neither a market mechanism to buy or sell gas in an efficient manner in South East Europe, nor a price discovery mechanism to determine spot prices, and gas exchange is based on bilateral agreements.

Energy security has been very high on the list of the EU energy and foreign policy agenda in the last decade. The main goals of the E.U. in the energy security domain are to decrease the energy dependence of member states on as few external suppliers as possible and to promote stable market rules which will make energy markets open and liquid. The EU aims to ensure the diversification of gas supply in order to decrease the market share of the largest foreign gas suppliers, and especially that of its biggest supplier, Russia, in an effort to shift price negotiations to the benefit of European buyers. The transition to a hub-based pricing mechanism is considered by many as a solution to EU's energy dependence problem. Nevertheless, it should be noted that spot pricing does not imply that natural gas prices will necessarily be lower than oil prices, just that gas prices will be formed based on supply and demand dynamics for gas, rather than for oil.

Today, there are nine (9) natural gas hubs operating across Europe. According to the International Gas Union, gas-on-gas competition in Europe increased from 15% in 2005 to 45% in 2012 while oil indexation decreased from 78% to 50% during the same period. 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 by 2014. 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). SE European countries (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 (Croatia, Romania) and three others cover small percentage shares from domestic gas (Bulgaria, Serbia, Turkey).

According to IENE forecasts after 2018-19 some marginal gas quantities will become available 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 also from Kurdistan, and most likely 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 two FSRU¹ units are planned to be based in Kavala and Alexandroupolis in Northern Greece, with the prospect of feeding gas quantities into the Greek, Bulgarian and Turkish natural gas systems. The Trans-Anatolian Pipeline or TANAP, whose construction is due to start in 2014, will be connected to Greece through the Trans-Adriatic Pipeline (TAP) pipeline. 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.

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

Virtual trading hubs, such as NBP or TTF, do not 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 South Eastern Europe.

However, one could argue that the operation of a physical i.e. 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 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 South Eastern 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 pipeline connections planned in South Eastern Europe, as well as two FSRU facilities and an underground storage facility in Northern Greece. Both Greece and Turkey have expressed interest in establishing a gas hub for the region.

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.

The parallel establishment of two major regional hubs is foreseen, one in Thessaloniki linked to the Athens Energy Exchange (in the process of being set up) and the second in Istanbul linked to the EPIAS Energy Exchange (to be established). With anticipated marginal gas volumes in the initial range of 1-1,5 bcm to be available for trading as early as 2018, rising to 6,0 and possibly to 10,0 bcm and more by 2025, it may well become possible to see the realization of such projection. In a sense, having two regional exchanges will help considerably from a geographical aspect as the Istanbul one will take care of trades directed eastwards while the Thessaloniki one will deal with trades to the West and to the North.

The financial implications arising from the operation of these two likely hubs are considerable both in terms of planned infrastructure investment (of the order of €6,0 billion) and in terms of traded volumes (in excess of €4,0 billion per year with conservative churn ratios and minimal quantities). Although it is difficult, at this stage, to predict market behaviour and its reflection on spot prices, once the 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.

1. INTRODUCTION

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 [1]. According to the International Energy Agency (IEA), European spot prices are three to four times higher than those in the United States, but are still significantly lower than European long-term contract prices normally determined through oil indexation. As a result, there has been a lot of controversy over how natural gas should be priced.

Today, there are nine natural gas hubs operating across Europe. According to the International Gas Union, gas-on-gas competition in Europe increased from 15% in 2005 to 45% in 2012 while oil indexation decreased from 78% to 50% during the same period. 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 by 2014².

The Institute of Energy for South-East Europe (IENE) took the initiative and carried out a research project in order to examine the conditions and prospects for establishing a regional Gas Hub for South Eastern Europe. The findings of this research project are presented in this volume. At present, there is neither a market mechanism to buy or sell gas in an efficient manner in South East Europe, nor a price discovery mechanism to determine spot prices, and gas exchange is based on bilateral agreements.

According to IENE forecasts after 2018-19 some marginal gas quantities will become available 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 also from Kurdistan and most likely 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 two FSRU³ units are planned to be based in Kavala and Alexandroupolis in Northern Greece, with the prospect of feeding gas quantities into the Greek, Bulgarian and Turkish natural gas systems. The Trans-Anatolian Pipeline or TANAP, whose construction is due to start in 2014, will be connected to Greece through the Trans-Adriatic Pipeline (TAP) pipeline. 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

² In February 2011 the EU Heads of State declared the need to complete the internal energy market by 2014.

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.

Turkey's natural gas consumption has grown dramatically over the last decade – from a level of 15 bcm in 2000 to 45 bcm in 2012 – establishing the country as the largest natural gas consumer in South Eastern Europe. According to the IEA, Turkish gas demand is expected to increase even further, reaching 60 bcm by 2018. Turkey does not have any significant indigenous natural gas reserves and therefore the increase in Turkish gas demand has to be met almost exclusively from imports. Romania is the second largest consumer in the region (13,3 bcm in 2012), but has gas reserves of its own. If we exclude Turkey, the demand for natural gas imports has been shifted from Bulgaria (from 5,3 bcm in 2000 to 3 bcm in 2012) to Greece (from 2 bcm in 2000 to 4,5 bcm in 2012).

Figure 1. Dry natural gas consumption in South Eastern Europe.

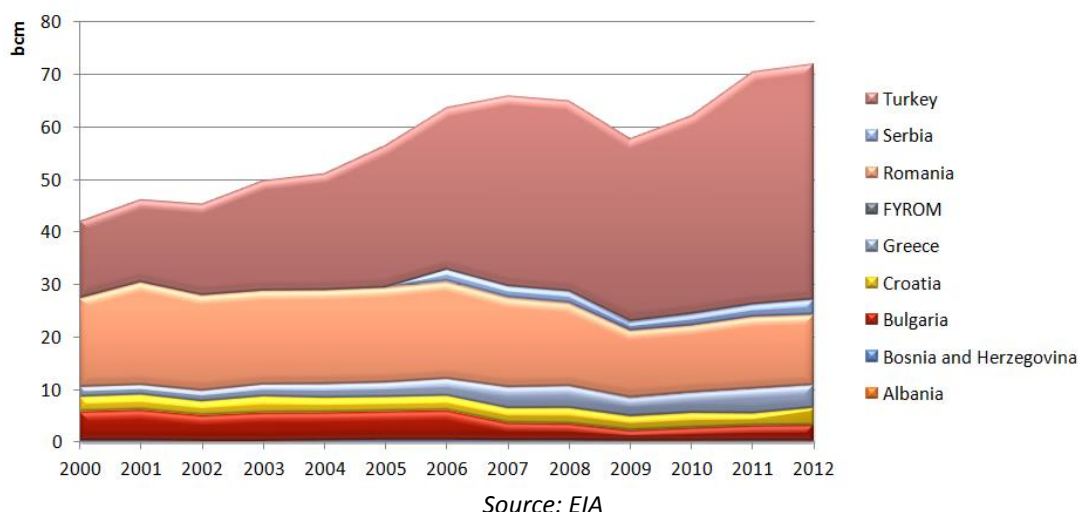
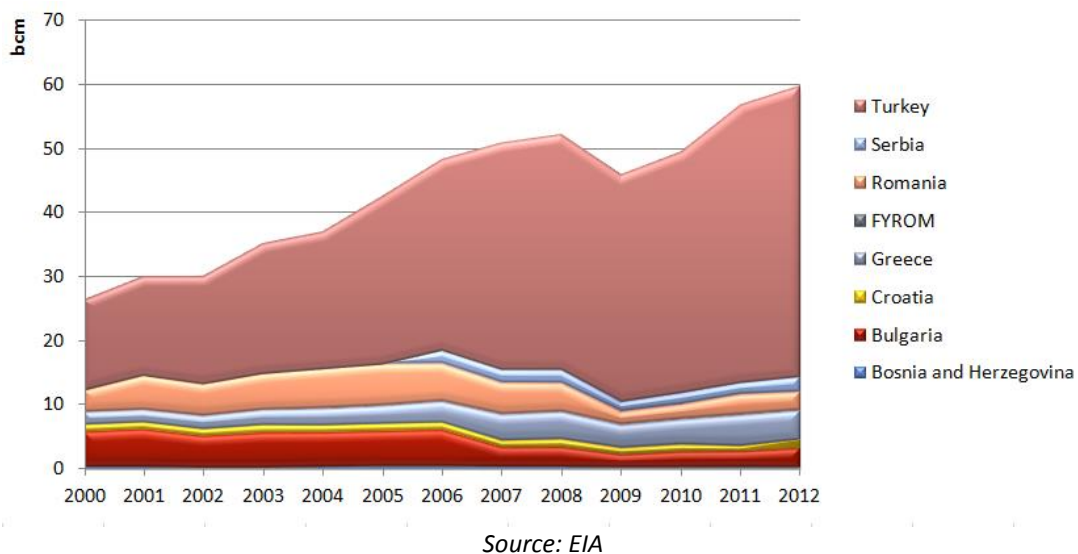
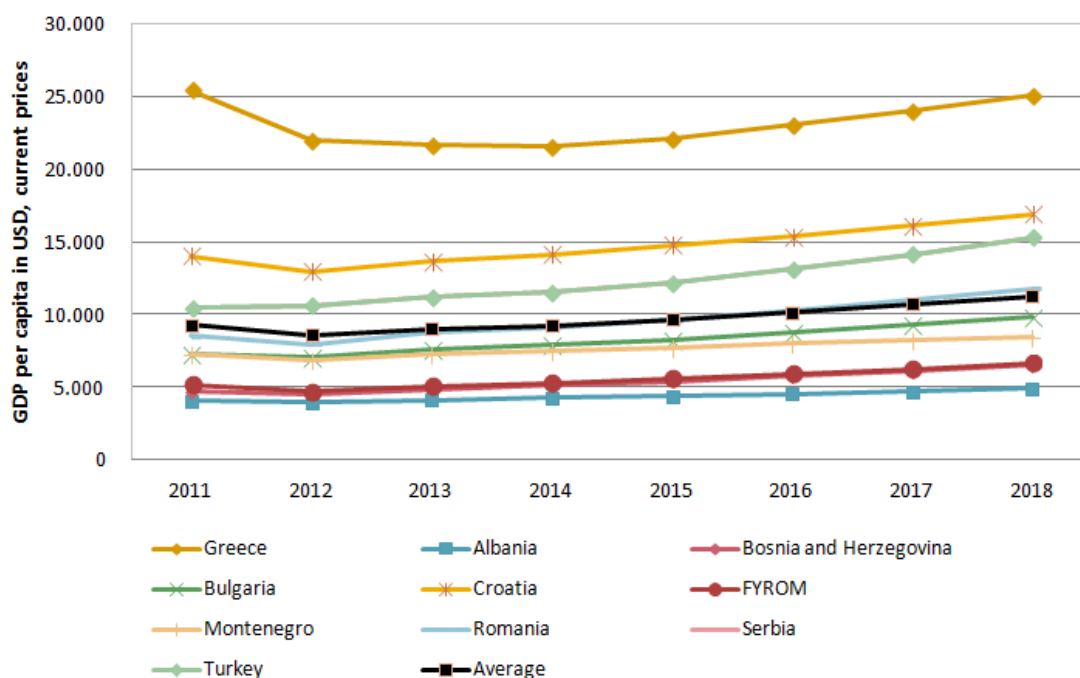


Figure 2. Dry natural gas imports in South Eastern Europe.

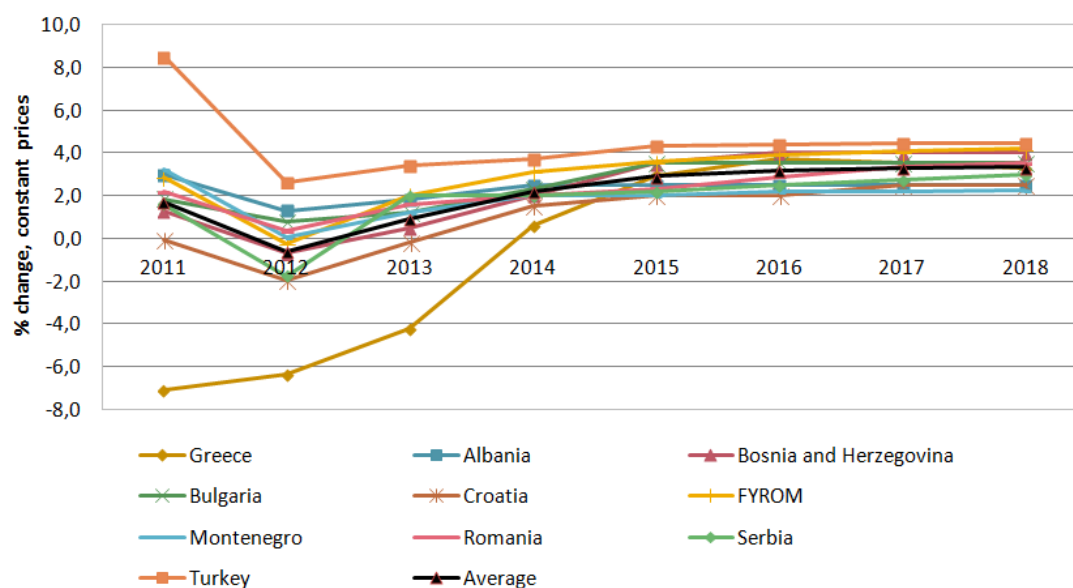


The South Eastern European gas market is also expected to be affected by the extent of the economic recovery and the stability in the region. The International Monetary Fund (IMF) estimates that there will be some expansion in the Gross Domestic Product (GDP) of the region. Greece is expected to have the highest GDP per capita in the region in 2018, with about 25 thousand US dollars in current prices. Greece is followed by Croatia, with 16,9 thousand US dollars and Turkey with about 15 thousand US dollars. Greece shows the highest divergence in the regional GDP growth rate, which was as low as -7,1% in 2011, according to the IMF. The country is projected to return to positive growth rates from 2014 onwards. By contrast, the Turkish economy grew by 8,5% in 2011 and is expected to continue to grow, with an increase rate that exceeds 4% from 2015 and on. For the period 2014-2018 the average growth rate in the region is estimated to increase from 2,2% in 2014 to 3,3% in 2018.

Figure 3. Projected GDP per capita in USD in South Eastern Europe (current prices).



Source: IMF

Figure 4. Projected GDP percent change in South Eastern Europe (constant prices).

Source: IMF

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

This paper focuses on the requirements for the establishment of a natural gas trading hub that will allow for natural gas prices to reflect local demand and supply. In Chapter 2, there is a review of the existing natural gas trading hubs, while in Chapter 3 the European energy exchanges are presented. In Chapter 4 there is a brief review of gas pricing mechanisms and current regional trends are analyzed. In Chapter 5 the perspectives for existing and potential suppliers of the European gas market are examined, while in Chapter 6 the profile of South Eastern Europe as a gas transit region is analyzed. In Chapter 7, the role of key regional players is examined, as well as their ability to support a competitive natural gas market. In Chapter 8 the framework for the creation of a regional gas hub is defined and the basic parameters for the development of a regional gas trading hub are set out. The aforementioned Chapter also includes a SWOT analysis of the operation of the gas hub. Finally, Chapter 9 presents the economic implications from the operation of a natural gas hub in South Eastern Europe and Chapter 10 provides a summary of the conclusions of the Study.

2. EUROPEAN NATURAL GAS HUBS

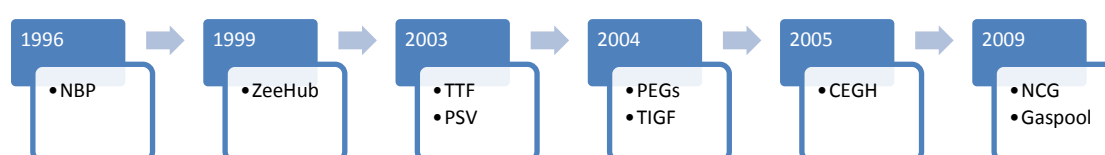
2.1. INTRODUCTION

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.

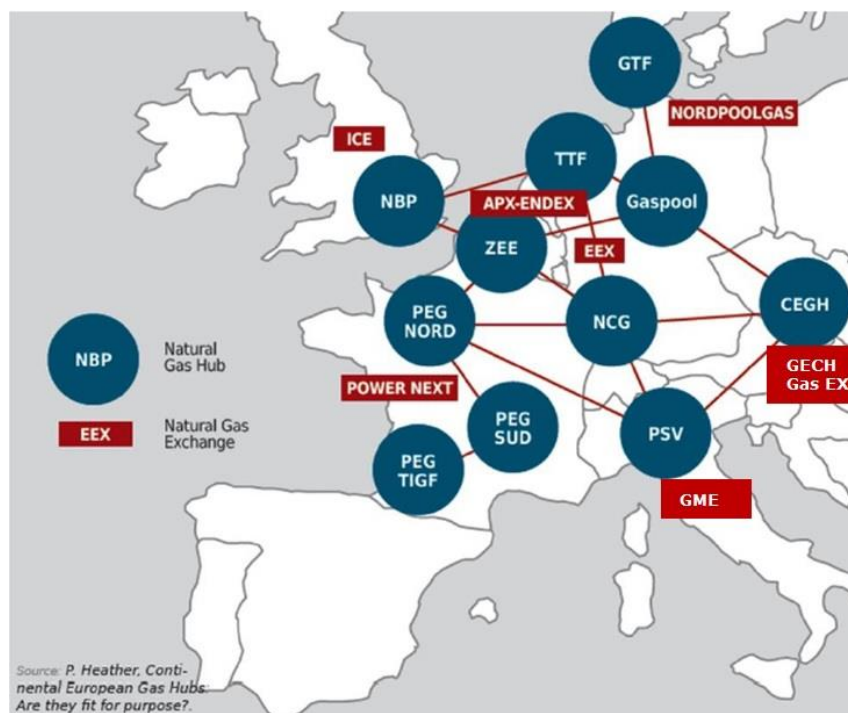
The new market model does not include the creation of a single European regulator. To the contrary, its philosophy is to build on the existing contractual, regulatory and operational arrangements of national TSOs and regulators and facilitate the efficient use of cross-border capacity with transparent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

Figure 5. European Union - Natural Gas Hubs Evolution.



The National Balancing Point (NBP) in the UK is the oldest and most liquid gas hub in Europe (1996). Due to 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. New hubs were created, with the French Point d' Exchange de Gaz (PEG) Nord and Sud and the German Gaspool and Netconnect Germany (NCG) being the most important trading points. Nevertheless, hubs in the UK, the Netherlands and Belgium remain the most liquid markets in Europe.

Picture 1. European gas hubs and exchanges.



2.2. NATURAL 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.

Table 1. Hub types in Europe.

Physical hubs	Country	Hub type
Central European Gas Hub (CEGH)	Austria	Transit
Zeebrugge (ZEE)	Belgium	Transit
Virtual hubs	Country	Hub type
Gaspool (GPL)	Germany	Transition
National Balancing Point (NBP)	United Kingdom	Trading
NetConnect Germany (NCG)	Germany	Transition
Points d'Echange de Gaz Nord (PEG)	France	Transition
Points d'Echange de Gaz Sud (PEG)	France	Transition
Points d'Echange de Gaz TIGRF (PEG)	France	Transition
Punto Di Scambio Virtuale (PSV)	Italy	Transition
Title Transfer Facility (TTF)	The Netherlands	Trading

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 [2]. 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. The only two mature hubs, according to the OIES, Britain's National Balancing Point (NBP) and the Dutch Title Transfer Facility (TTF). *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. There are two transit hubs in Europe: the Central European Gas Hub (CEGH) in Austria and the Zeebrugge hub (ZEE) in Belgium. *Transition hubs* are virtual hubs which are relatively immature, but have set benchmark prices for natural gas in their national markets. These include the German Gaspool Balancing Services (GPL) hub and the NetConnect Germany (NCG) hub, the French Points d' Echange de Gaz (PEGs) and the Italian Punto di Scambio Virtuale (PSV).

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.

Picture 2. Natural Gas exchanges.



Source: Bergen Energi

Exchanges in turn contribute to the growth of hubs, especially in the case of the ICE Endex, the EEX and Powernext, which have created trading platforms for the NBP and TTF, Germany's NCG and GPL, and the PEG Nord, respectively.

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.

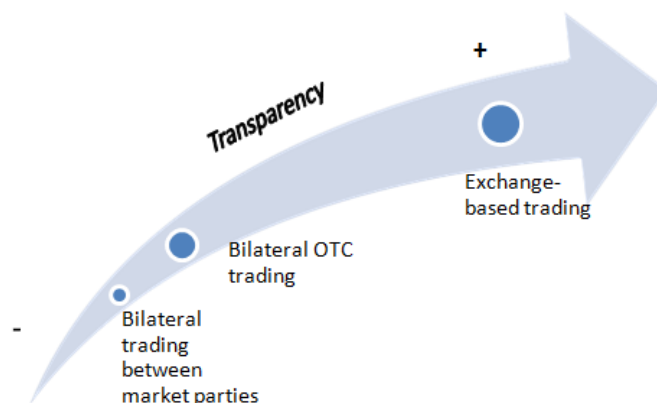
An **over-the-counter market** does not use a centralized trading mechanism i.e. a shared platform to aggregate bids and offers and allocate trades. OTC trades are bilateral non-regulated deals in which buyers and sellers negotiate terms privately, often not being aware of the prices currently available 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 [3].

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 [4].

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 obligations⁴. Exchange-based trading also increases transparency in the natural gas market through the price signals it provides.

Figure 6. Transparency on bilateral and exchange-based trading.



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 [5].

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

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.

2.3. NATURAL GAS HUBS OVERVIEW

European gas hubs offer a variety of contracts and services. In order to understand the natural gas market in Europe well, it is necessary to analyze each hub individually.

2.3.1. 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 Hub⁵ in the U.S., 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 Shippers⁶ in order to trade, can only trade NBP on the ICE futures. Today around 70% of the total trade corresponds to Over-The-Counter volumes and the remaining 30% to ICE volumes [2].

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) [6]. 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 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.

National Grid serves the role of balancing the system on a daily basis. It is the only gas hub of this type, except for the TTF which was created on a similar basis [7].

Currently there are three connections between Britain and the EU:

- The BBL (Balgzand Bacton Interconnector from Bacton in Norfolk to the Netherlands),
- The Interconnector UK (from Bacton in Norfolk to Belgium),

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 Irish Interconnectors (from Moffat in Scotland to Northern Ireland, the Republic of Ireland and the Isle of Man).

The Interconnector, originally designed to serve gas export from the UK under long-term contracts, is a natural gas pipeline connecting the Bacton Terminal with the Zeebrugge Terminal in Belgium. Until the Interconnector was constructed, the UK market operated separately from the continental market. The construction of the Interconnector coincided with the liberalization period of the UK gas market and promoted price interaction with the Continent by arbitrage.

Picture 3. The Interconnector.



Source: Oxford Institute for Energy Studies

The NBP has managed to continue to grow during the last 10 years due to its close pricing correlation to global oil prices and its attractive virtual design. Its range of participants includes producers, LNG suppliers, retailers, power generators, industrial users and trading houses.

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.

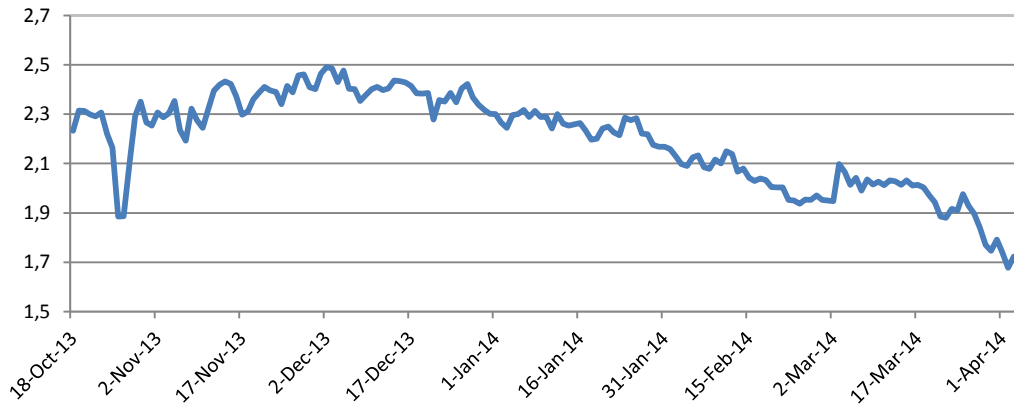
The price set on the OCM is used as a reference for the System Average Price (SAP), the weighted average price of all trades for the relevant gas day on the OCM platform. Based on the SAP, the System Marginal Buy Price (SMBP) and the System Marginal Sell Price (SMSP) are computed (Fig.6).

Trading activity at the NBP accounted for 62% of all continental European gas trading activity in 2012, from nearly 90% in 2007. It has attracted more participants, but its lead over TTF is fading. Figure 7 depicts the physical and traded NBP volumes, which are clearly declining, in favor of the Dutch TTF, which is slowly becoming the new reference for natural gas trade in Continental Europe.

Future trades make the NBP the most liquid European hub. The NBP's churn ratio⁷, which is a liquidity indicator, is usually around 20, while it rose to 23 in 2013. 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 [8].

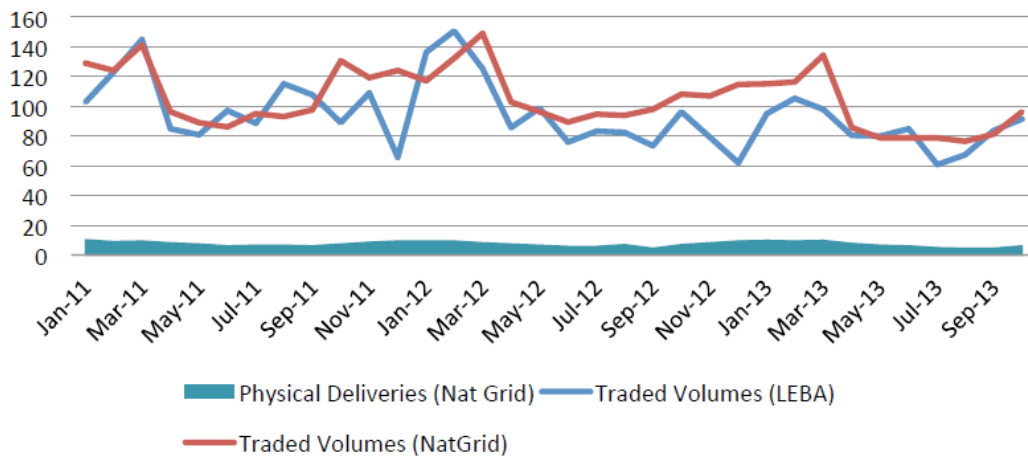
⁷ The churn rate describes the ratio between physical transfers and traded volumes at the VTP and is therefore an indicator of trading activity and liquidity within the market area. A churn rate of 10 is considered a threshold of a mature market.

Figure 7. SAP: Weighted average price of all trades for the relevant gas day on the OCM platform in €/KWh (€/£ = 0,21).



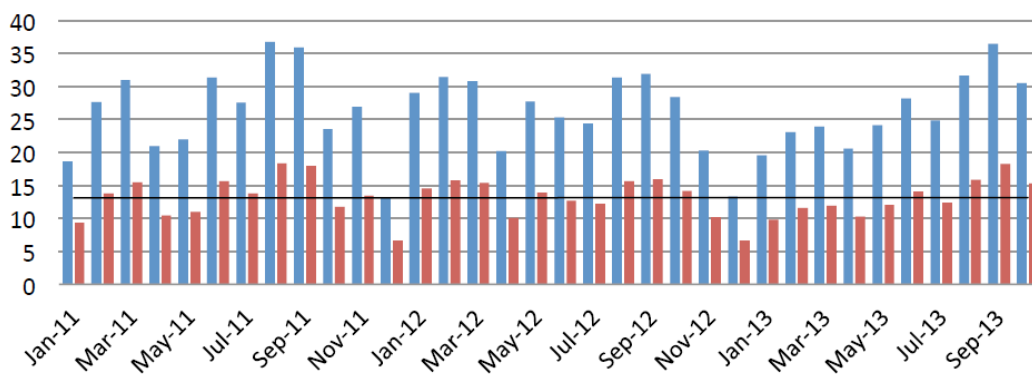
Source: ICE Endex

Figure 8. Traded volumes at the NBP.



Source: IEFÉ

Figure 9. Monthly churn ratios at the NBP.



Source: IEFÉ

2.3.2. 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 all natural gas in the Dutch transmission system.

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 [9]. It was established in 2003 in order to promote gas trading in one market place 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 new 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 [8]. 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.

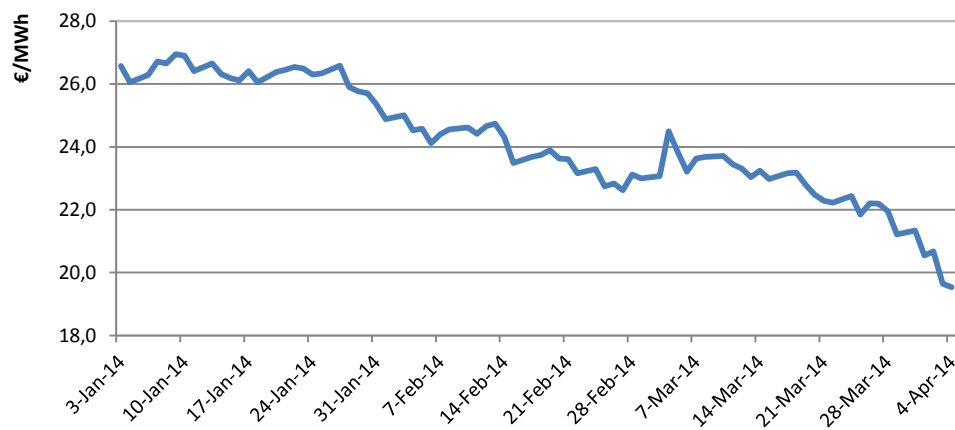
TTF's location between Germany, France and the North Sea coast enables it to transfer gas from Norway to the German and French markets. The TTF is also connected to Britain's NBP hub. Additionally, the new Dutch liquefied natural gas (LNG) terminal, opened in 2011, gives TTF direct access to the global 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 (see Fig. 9) is a volume-weighted average price of all orders which are executed on the gas day preceding the day of delivery [10].

Fig. 11 shows the development of monthly volumes of the last five years at the TTF (January 2009 – December 2013). November 2013 saw TTF volumes reach their highest levels since

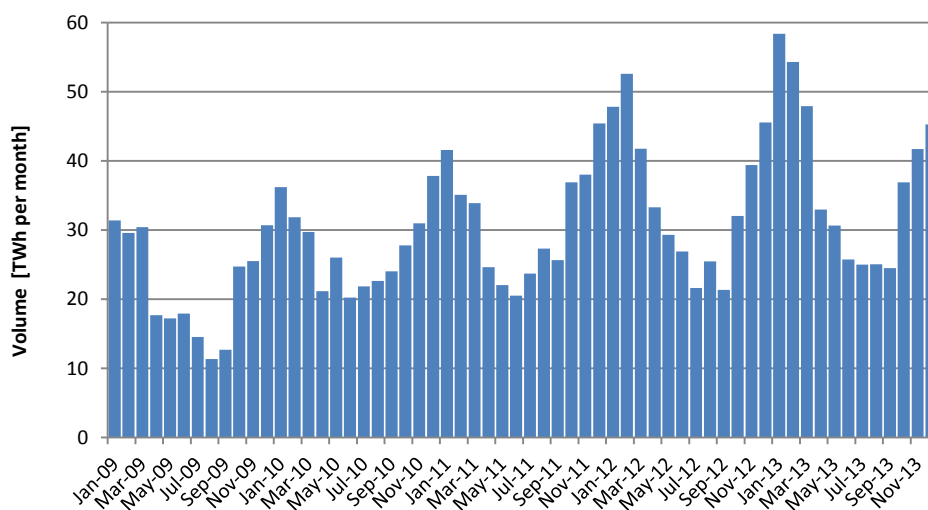
January 2011. The TTF continues to grow relative to the NBP. Wholesale gas and gas futures trading volumes are rising in the Netherlands and falling in Britain, a sign that Dutch hub TTF is drawing financial traders away from NBP. The Netherlands with its good transport links and North Sea gas reserves has become the preferred market for continental European gas forwards, which also creates a good basis for short-term physical deals. Increased price convergence between the Euro zone's Dutch, German, Belgian and French markets also means the TTF attracts hedging and risk management from non-Dutch market participants. The churn ratio of TTF also exhibits an upward trend and is comparable to that of the NBP, with the gap between them continuously narrowing.

Figure 10. TTF Day-ahead Index (End-of-Gas-Day).



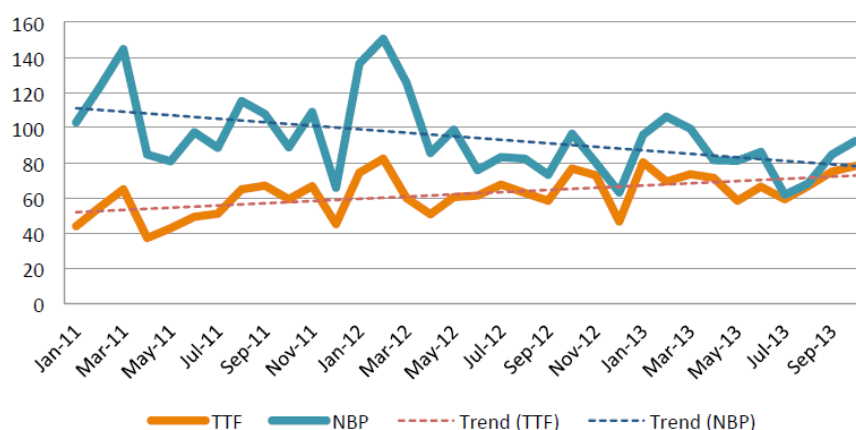
Source: ICE ENDEX

Figure 11. TTF net monthly volumes (Jan. 2009 – Dec. 2013).



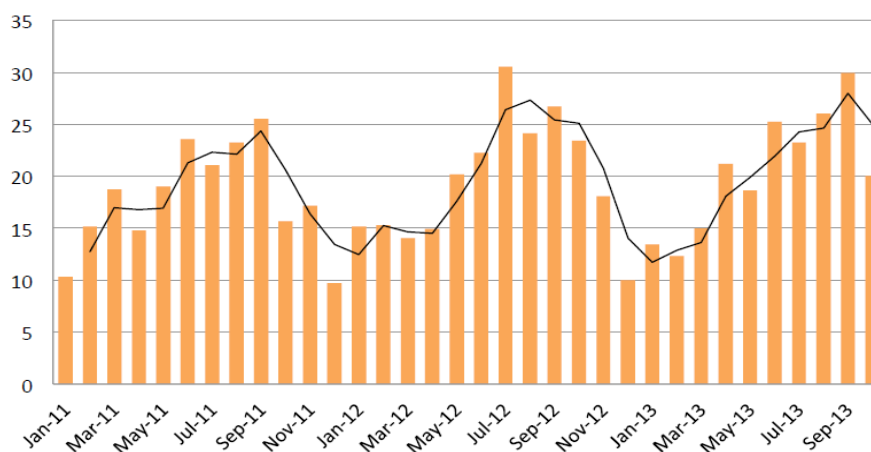
Source: Gasunie transport services

Figure 12. NBP and TTF traded volumes.



Source: IEFE

Figure 13. TTF churn ratio.



Source: IEFE

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 trading gas 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).

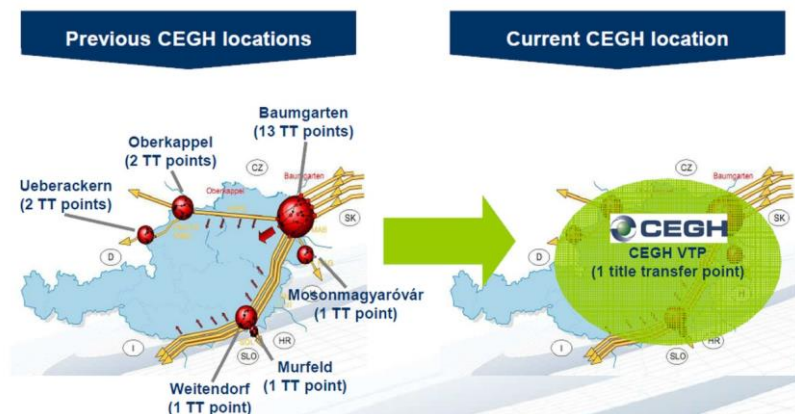
CEGH cooperates with several different TSOs, particularly in Baumgarten, OMV’s main gas compressor station (OMV, TAG, BOG, Eustream). Approximately one third of all Russian gas

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. By 2013 there were 161 registered trading members on the OTC market [11].

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 [12]. 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.

Figure 14. Introduction of the CEGH VTP and consequences for CEGH Title Transfer Points (TTFs).



Source: CEGH

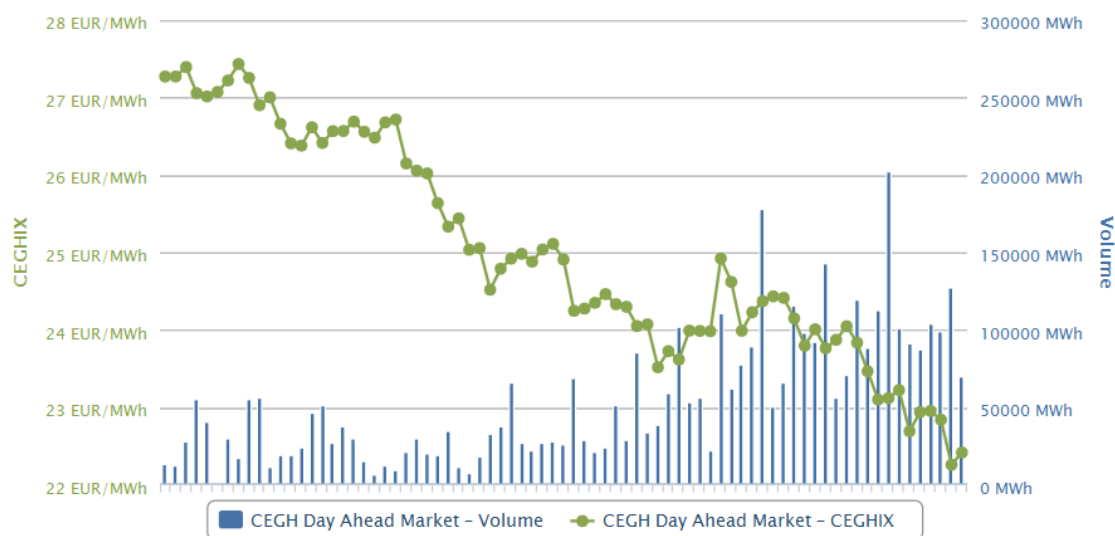
The hub in Austria consists of three separate networks, known as Market Areas. The main balancing zone, located in the east of Austria, has a high pressure transmission grid and a high and low pressure distribution grid. The two smaller networks are located in the west central (Tirol) and western (Voralberg) 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. Figure 15 presents the evolution of the spot index against the day-ahead market volume during the first quarter of 2014.

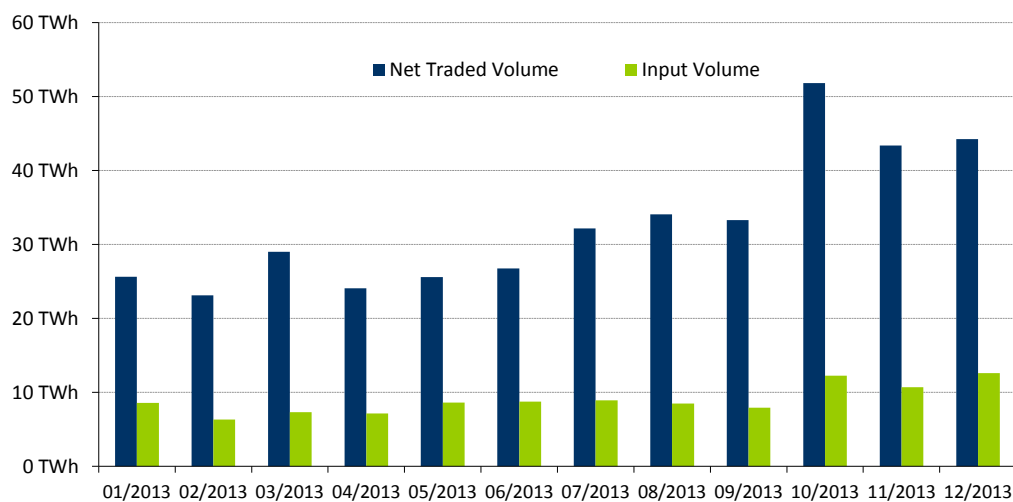
In 2013, 393 TWh (35 bcm) were nominated at the CEGH-Virtual Trading Point (VTP), indicating a successful start for the new Austrian Gas Market Model. Volumes traded at the CEGH Gas Exchange of Wiener Boerse have showed a significant increase, since the traded volume rose by more than 370% to 13,22 TWh, compared to 2012. The CEGH churn ratio also increased, rising to an average of 3,65 in 2014 from 3,53 in 2012.

Figure 15. CEGH Day ahead market (January – March 2014).



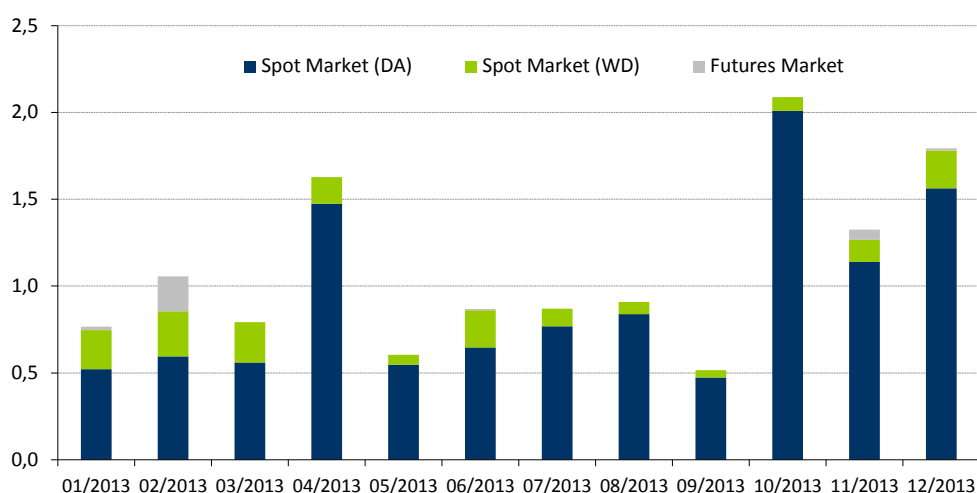
Source: CEGH

Figure 16. CEGH OTC market (monthly).



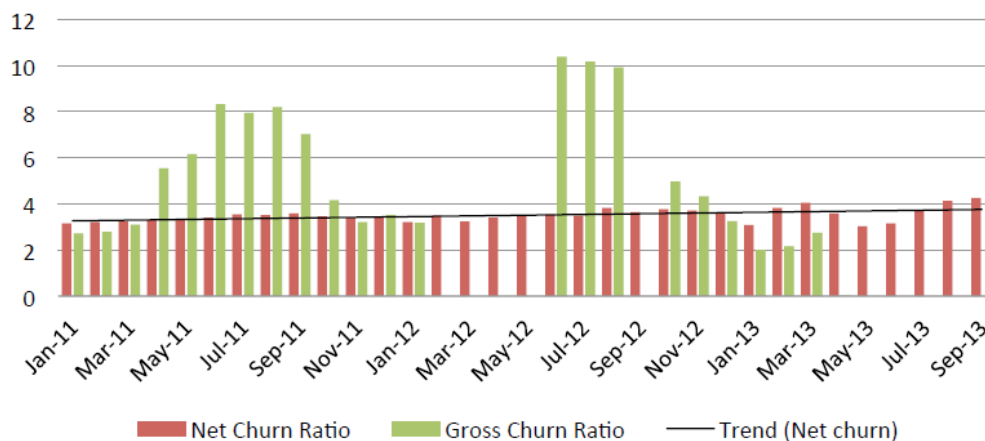
Source: CEGH

Figure 17. CEGH gas exchange volumes.



Source: CEGH

Figure 18. Churn ratios at CEGH.



Source: IEFÉ

2.3.4. ZEEBRUGGE (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 EU27, with an overall throughput capacity of 48 bcm/year i.e. 10% of the border capacity needed to supply the EU27. 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 [13].

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.

Picture 4. The Zeebrugge hub.



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.

Source: Fluxys

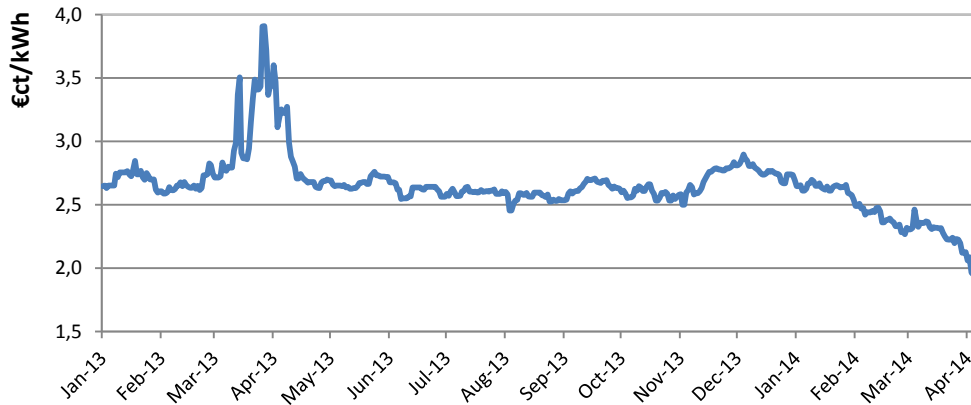
Belgium has significant storage facilities, with the most important being the Loenhout underground storage, with a working capacity of 0,7 bcm of high-calorific natural gas, a withdrawal capacity of 625 mcm/hour and an injection capacity of 325 mcm/hour. The Zeebrugge LNG Terminal on the other hand has 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 new natural gas entry/exit launched by Fluxys in October 2012 comprises one single trading hub where both virtual and physical services are available. Fluxys Belgium launched its new central trading point ZTP so that it coincides with the launch of the new 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.

According to DG Energy, 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 [14]. 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

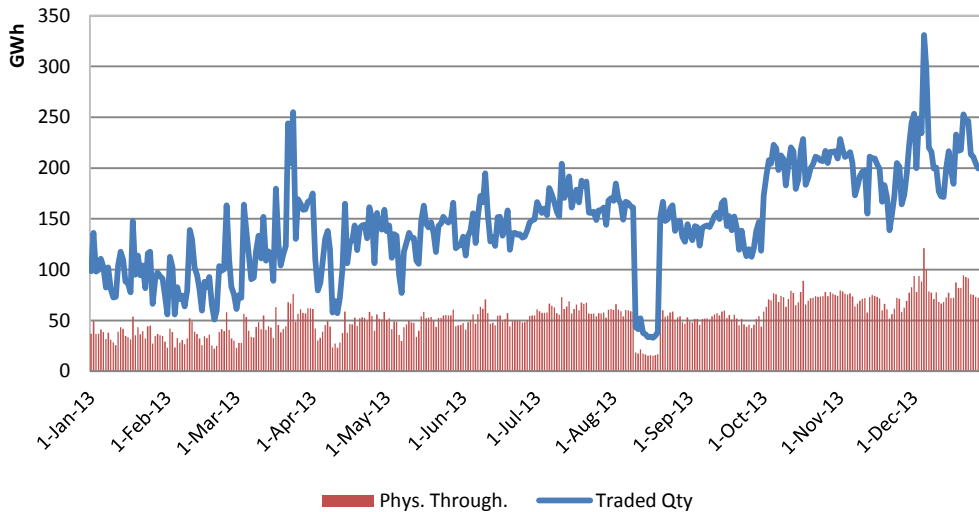
of the high level integration of natural gas infrastructures in Belgium. According to Fluxys, a total volume of 752 TWh was traded at Zeebrugge Beach and ZTP in 2012, while in 2013 the total traded volume increased to 825 TWh. Zeebrugge Beach 2012 traded volumes remained at the same level as in 2011 (742,5 TWh compared to 769,8 TWh in 2011), while in 2013 they increased to 772 TWh. ZTP traded volumes reached 53,8 TWh in 2013. The churn ratios at ZTP (see Fig. 22) exhibit a downward trend from January 2011 to September 2013, which can be attributed to the growth of physical supplies which has overtaken the growth in traded volumes.

Figure 19. APX ZTP Day – Ahead Index.



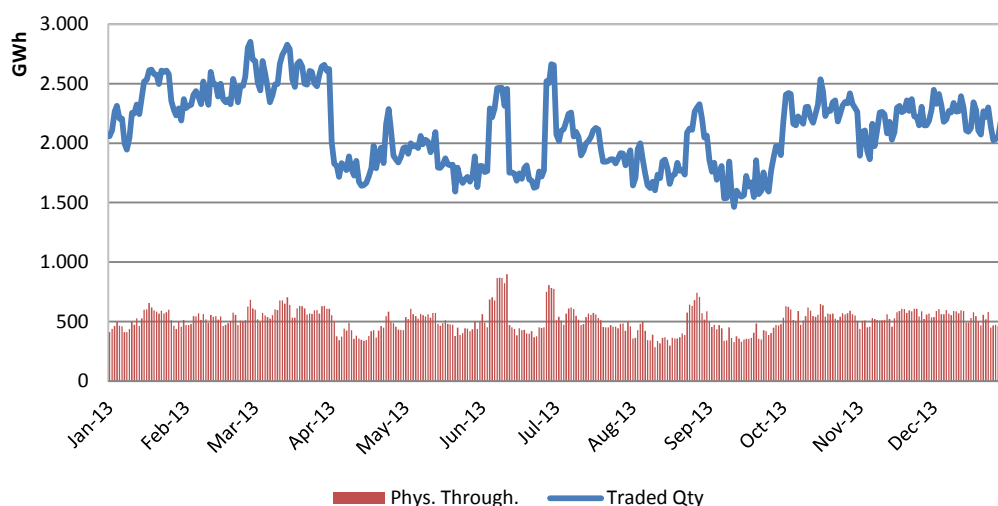
Source: Gaspool Data Service

Figure 20. Traded and delivered volumes at ZTP (2013).



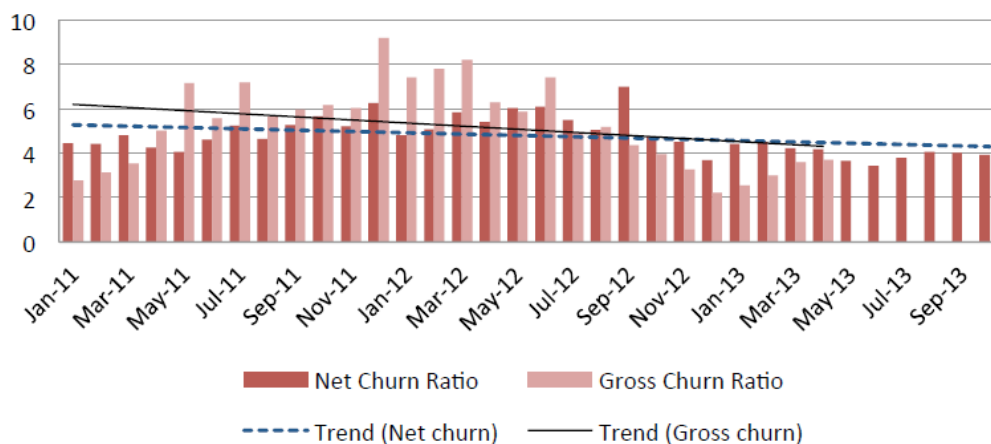
Source: Huberator

Figure 21. Traded and delivered volumes at Zeebrugge Beach (2013).



Source: Huberator

Figure 22. Churn ratios at ZTP.



Source: IEFE

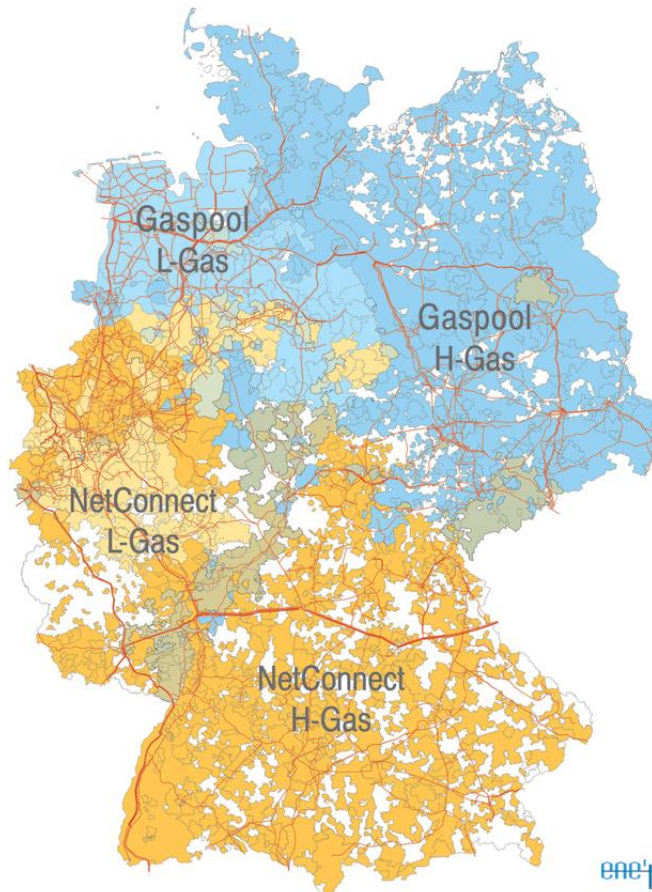
2.3.5. NETCONNECT GERMANY (NCG)

NetConnect Germany GmbH & Co. KG is Germany’s largest natural-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. According to the IEA, the German storage capacity is 20,4 bcm. Germany, in combination with France and Italy, has more than 70% of the EU storage capacity. 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 [15].

Picture 5. Map of the German gas market area.



Source: enet.eu

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.

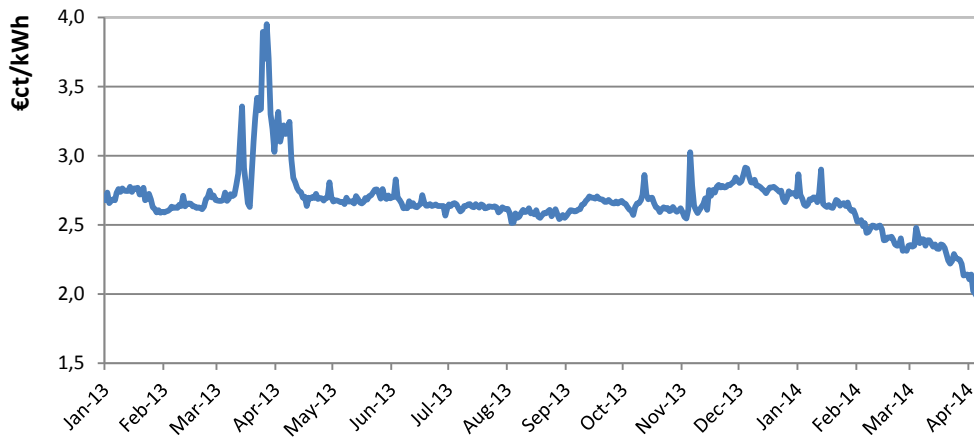
The new NCG, formed on the 1st of October 2011, improved competition and price formation and increased market liquidity. The trade volume at the two German trading points, NCG and Gaspool, has increased significantly making Germany's natural gas network more and more important for the European network.

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 300 trading participants for H gas (high calorific natural gas) and 150 trading participants for L gas (low calorific natural gas).

The reference price at NCG shows a downward trend lately, while there is significant convergence with the Gaspool price. On the NCG total trading volumes rose 26% in 2009/2010 and 14% in 2010/2011. Nominated traded volumes increased by more than 20% from around 1,4 million GWh in gas year 2011/2012 to around 1,7 million GWh in gas year 2012/2013 [16]. Its average churn rate never fell below 3 throughout the gas year 2012/2013. In April 2013 the H gas churn rate reached a value above 4 for the second time. A churn rate of four indicates that, on average, every gas volume traded via NCG's VTP has

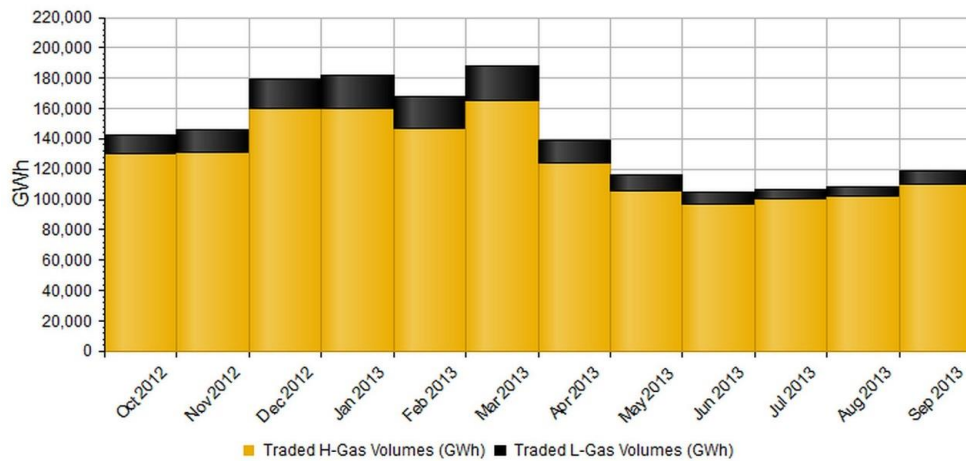
four different owners before it reaches the consumer. Figure 25 depicts the upward trend of the churn ratios at NCG as well as Gaspool.

Figure 23. Reference price at NCG.



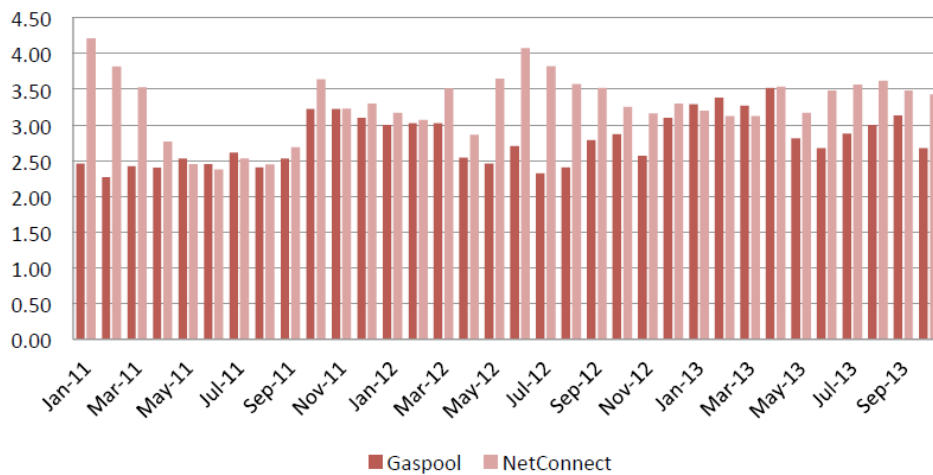
Source: Gaspool Data Service

Figure 24. NCG cumulative development of nominated volumes (Oct. 2012 – Sept. 2013).



Source: NetConnect Germany

Figure 25. Churn ratio at NCG and Gaspool.



Source: IEFE

2.3.6. GASPOOL BALANCING SERVICES

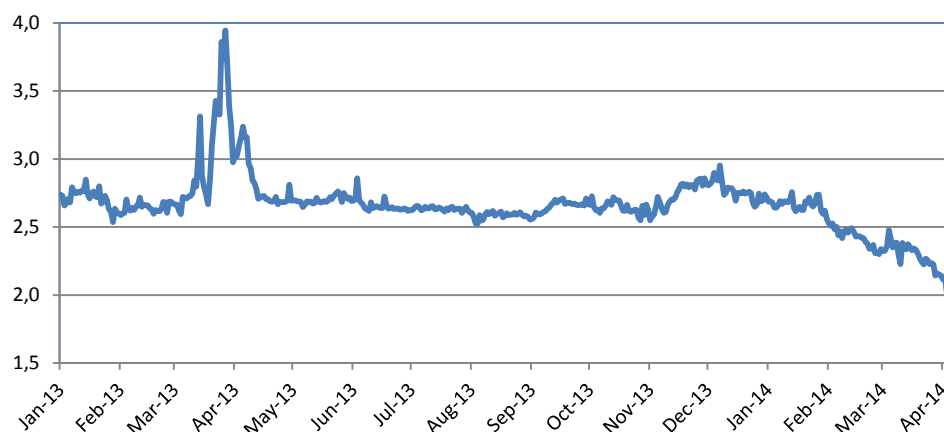
Gaspool is the second natural gas hub of Germany and, like the NCG, it is run by six TSOs. It is a subsidiary of GASCADE Gastransport GmbH, Gastransport Nord GmbH, Gasunie Deutschland Transport Services GmbH, Nowega GmbH and ONTRAS Gastransport GmbH. The Gaspool market area, situated in Northern Germany, incorporates approximately 350 downstream natural 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. This is possibly the only transparent official price available for European oil-indexed long term gas contracts [17]. 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 [18].

Since Gaspool started, trading volumes have increased by 120%. There was a sharp rise in the quantities traded at the Gaspool hub in the whole of the 2012/2013 gas year (ending on October 1). From around 946 TWh traded in the 2011/2012 gas year, the traded volume rose to approximately 1.188 TWh in 2012/2013 gas year. The rise in gas volumes offered at the GASPOOL hub has pressured prices at the smaller German trading point in relation to the NCG.

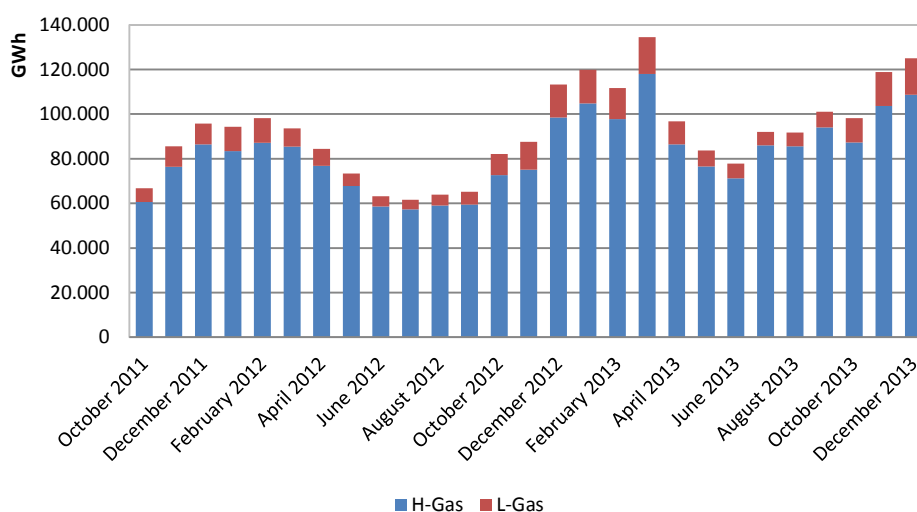
As already mentioned, there is a continuous upward trend in churn rates. In October 2013, the churn rate for H-gas at Gaspool was 3,132 and for L-gas it was 1,717, both well up on the previous year. This positive trend represents a year-on-year increase of 13,8%.

Figure 26. Reference price at Gaspool.



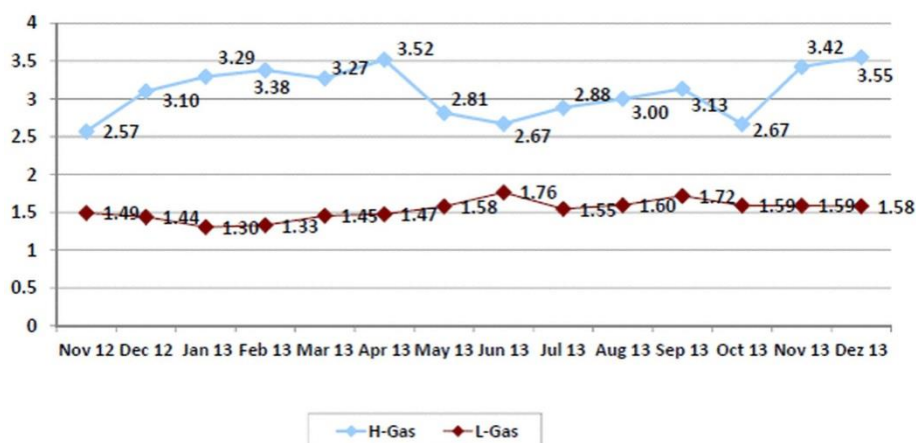
Source: Gaspool Data Service

Figure 27. Trade volumes at Gaspool hub.



Source: Gaspool

Figure 28. Gaspool churn rate for H-Gas and L-Gas.



Source: Gaspool

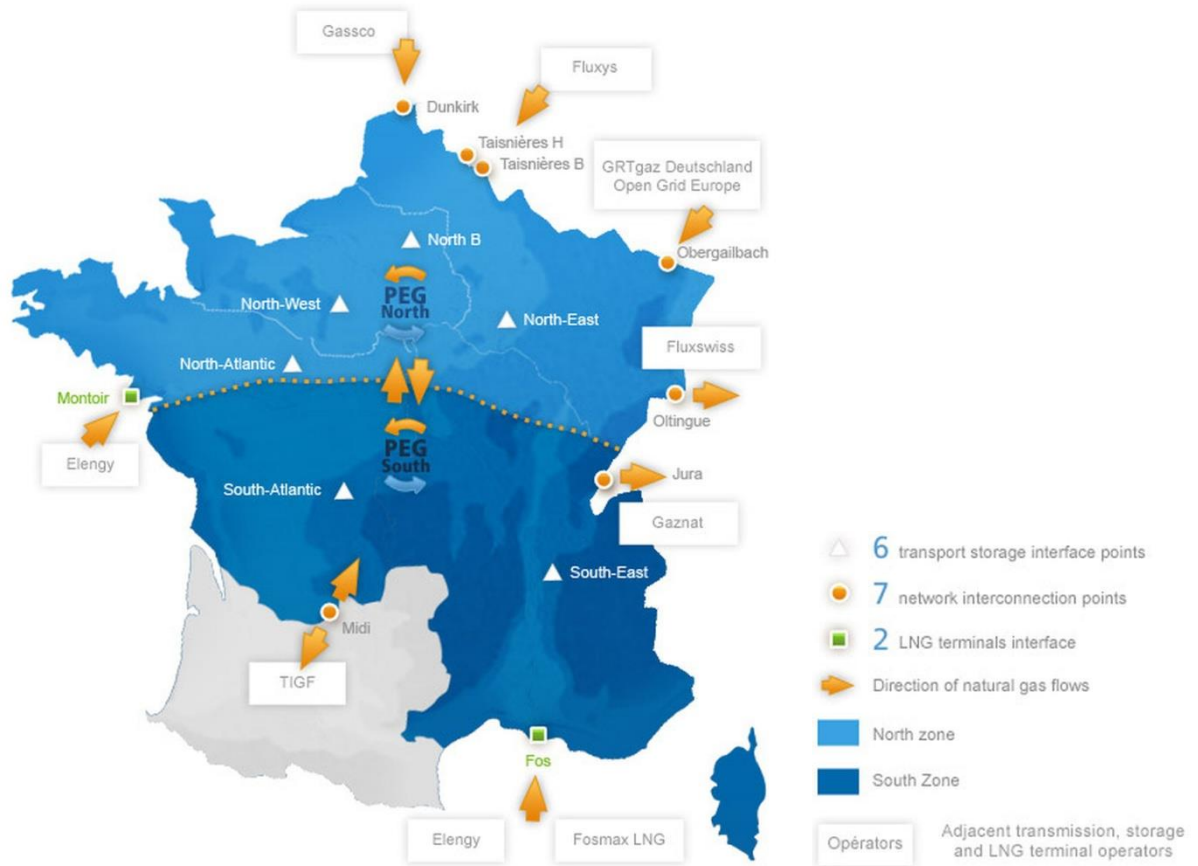
2.3.7. POINTS D' ECHANGE DE GAZ (PEGS)

The French gas market is facilitated by the Gas Transfer Points (PEG: points d'échange de gaz), owned by Gaz de France. Natural gas trades take place by deliveries and physical removal of quantities of gas at the PEGs. The PEGs are linked to three balancing areas for the gas transmission network: the Northern zone (GRTgaz), the Southern zone (GRTgaz) and the South-West zone (TIGF). To each of the three balancing zones there is a corresponding virtual trading point: PEG Nord, PEG Sud and PEG TIGF.

On the PEGs market participants can exchange quantities of gas either via OTC bilateral agreements or via the gas exchange operated by the French investment firm Powernext. Services offered at these French hubs are varied. The PEG Nord offers contracts made on Day-ahead, Weekend, one month ahead, one quarter ahead, and one season ahead. Both the PEG TIGF and the PEG Sud offer contracts made on the Day-ahead and Weekend. Powernext offers spot contracts for all three hubs, as well as future contracts for the PEG

Nord. Nevertheless, the PEGs have only been used as balancing points rather than areas of trade due to low levels of liquidity.

Picture 6. Title Transfer Points and Transmission System in France.



Source: GRTgaz

While the North PEG has a satisfactory level of liquidity and competitiveness, both on the wholesale and retail markets, the South PEG and the TIGF PEG still have little liquidity. Thus, consumers, in particular industrial ones, do not have the benefit of market conditions as attractive as those at the North PEG.

Figure 29. French PEGs activity.



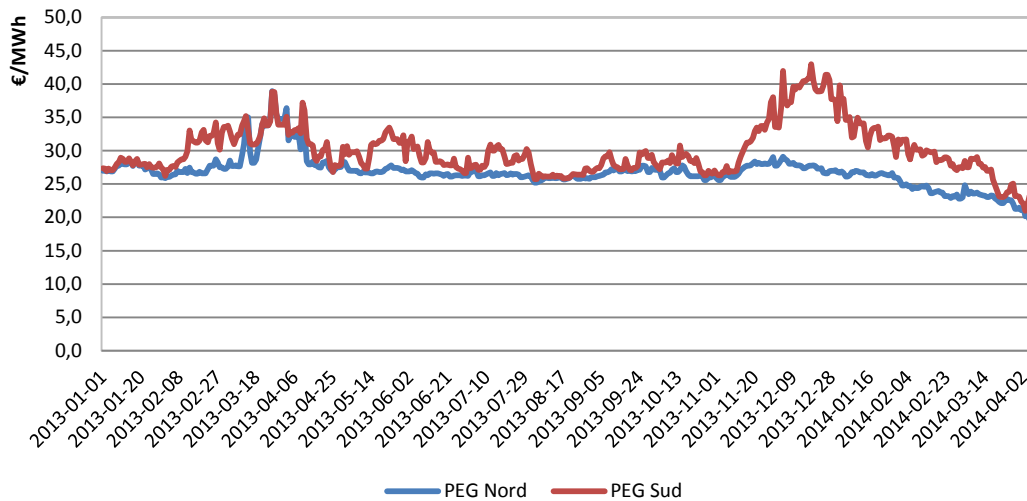
The PEGs have been recording a steady rise in trade, proportional to the rise in the number of players: there were 87 active players on the French PEGs in mid-2012.

Source: Gas in Focus-Observatoire du Gaz

Since July 2011, the price differential between regions decreased from €1/MWh to zero, most of the days. However, at the start of 2012 there was significant price divergence between the North PEG, and the South PEG and the TIGF PEG. These spreads are the consequence of physical transmission constraints between the North PEG and the South PEG because of the fall in LNG deliveries, as a result of high LNG prices in Asia [19]. As long as the LNG spot premium continues to decrease LNG deliveries in France, this price divergence is likely to continue.

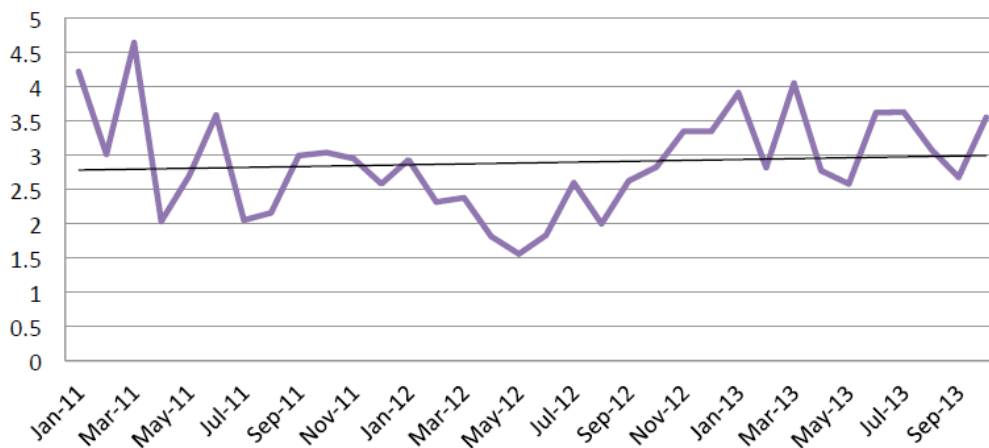
As depicted in Figure 30, in December 2013 there was also a significant divergence in the Daily Average Price (DAP) between PEG Nord and PEG Sud. Traded volumes have been relatively stable, while the very low churn ratios at the PEGs are indicative of the poor liquidity exhibited by the specific hubs.

Figure 30. Daily Average Price at PEG Nord and PEG Sud.



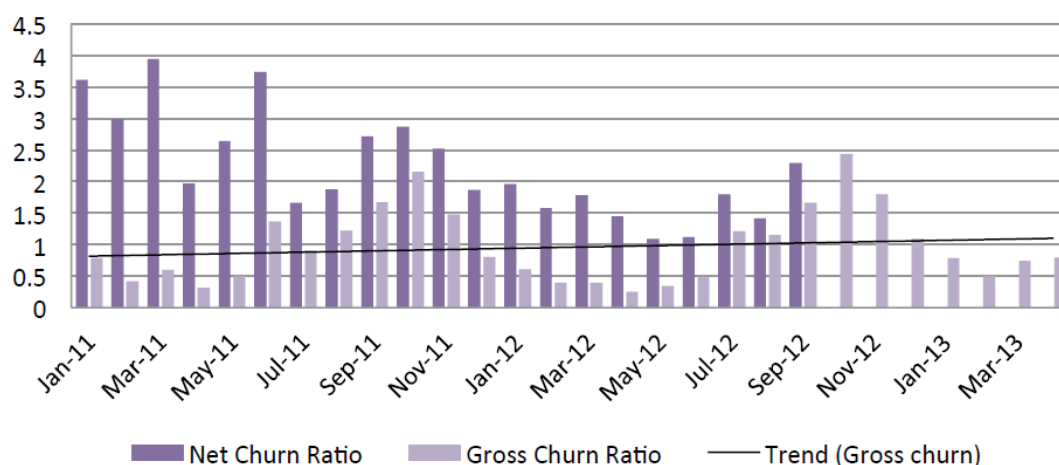
Source: Powernext

Figure 31. Traded volumes at PEGs (bcm).



Source: IEFÉ

Figure 32. Churn ratios at PEGs.



Source: IEFE

2.3.8. PUNTO DI SCAMBIO VIRTUALE (PSV)

Italy has strong gas demand growth since it generates almost half 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. There are around 150 operators trading gas on the PSV, from around 110 in 2011 and 82 in 2009.

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.

Picture 7. Italian gas transmission network.

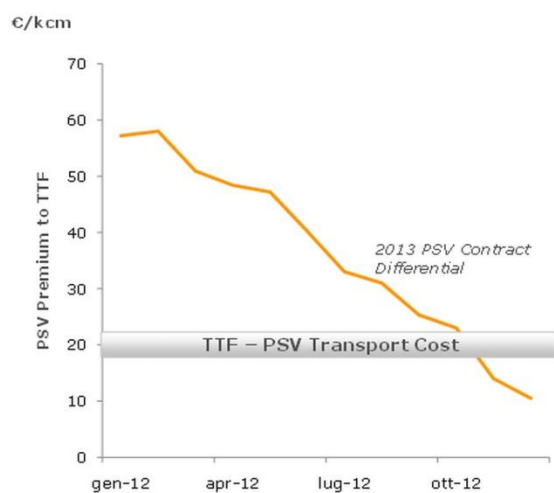


Source: Snam Rete Gas

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.

Figure 33. PSV premium to TTF.



Source: ENI

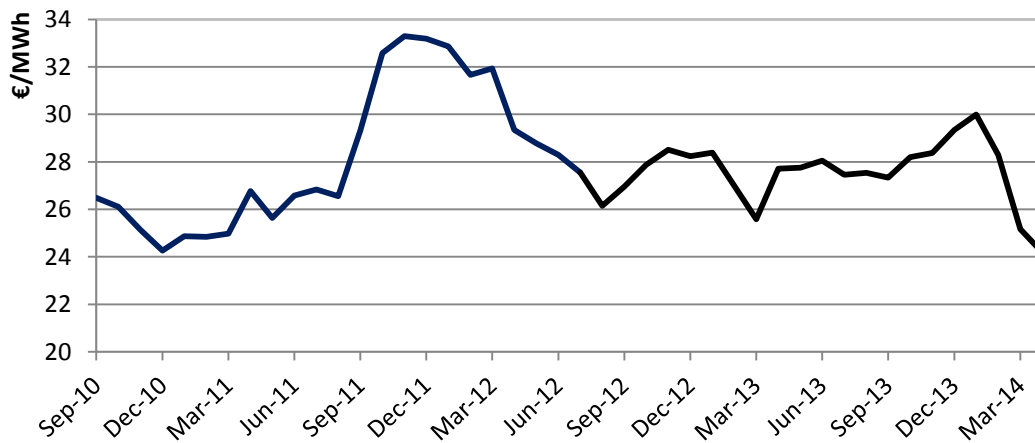
Indeed, Italian gas prices have been historically high. The price benchmark for gas on the Italian market is based on the TTF index plus costs of transportation of gas to Italy, with the rest of the pricing depending on the company making the deal. In 2012 the PSV premium to TTF started decreasing and therefore, PSV prices started to converge with the prices at the Dutch TTF and other North West European hubs, as a result of resolved capacity availability issues in linking infrastructure [67].

Figure 34 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 24,20 €/MWh in April 2014, which is the lowest monthly price in the examined period (September 2010 – April 2014).

Despite some signs of progress, the churn rate was 3 in 2013, compared with 19 at TTF and 23 at NBP. As previously mentioned, a churn rate of 10 is considered a threshold for a

mature market. The introduction of the PB-Gas balancing platform in 2011 led to an increase in liquidity and favors the shift to a balancing mechanism less based on storage, and more compatible with European balancing standards. Traded volumes have also started to increase.

Figure 34. MAGI Index from August 2012 and 70/30 weighting of GeEO transaction and quotation indices from September 2010 to April 2014.



Source: magindex.org

Figure 35. PSV traded volumes.

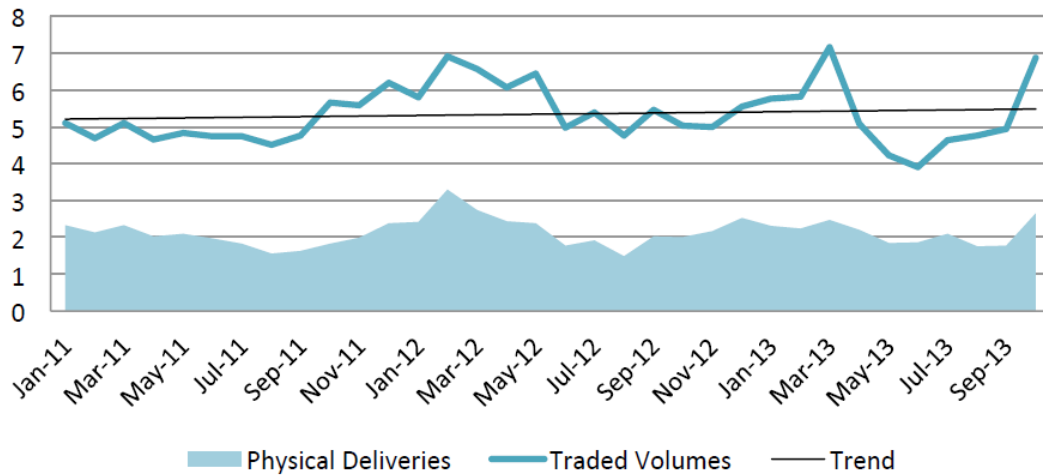
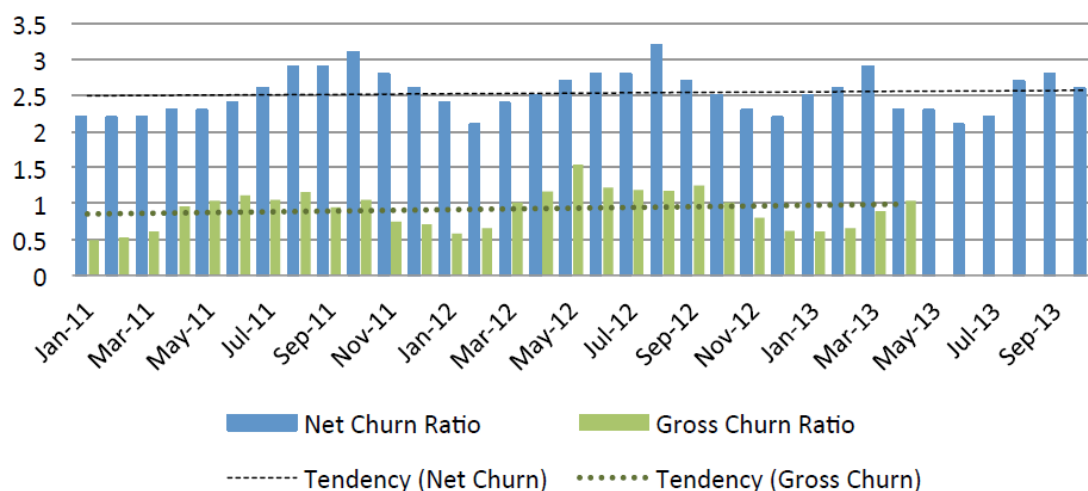


Figure 36. Churn ratio at PSV.



Source: IEFE

2.4. TRADING ACTIVITY AND PRICES AT EUROPEAN GAS HUBS

As shown in Table 3, in 2012 physical delivered volumes increased by 13% in European trading hubs, while traded volumes increased by 14%. The NBP is the European gas hub with the biggest physical volumes, accounting for a third of the total physical delivered volume. Physical delivered gas increased from 242 bcm in 2011 to 272 in 2012, despite the decrease in natural gas demand (-2%).

In 2012 European traded volumes recorded the smallest annual increase for at least seven years as reduced physical gas consumption, unusually low levels of price volatility and increased regulatory costs weighed on the market. According to analysts, total European traded volumes rose 6% to 34.000 TWh in 2012, despite the UK gas market posting no growth at all and trading at the Belgian Zeebrugge hub shrinking slightly in 2012. Trading activity at the NBP accounted for 62% of all continental European gas trading activity in 2012, from nearly 90% in 2007. The NBP still has more participants, but its lead over TTF is diminishing. According to ICIS Heren, NBP traded volumes have been following a downward trend since they hit a record high in 2011 on account of traders transferring volumes to mainland hubs and the Intercontinental Exchange (ICE).

Table 3. Nominated (net-traded) and physical volumes on European gas hubs (bcm).

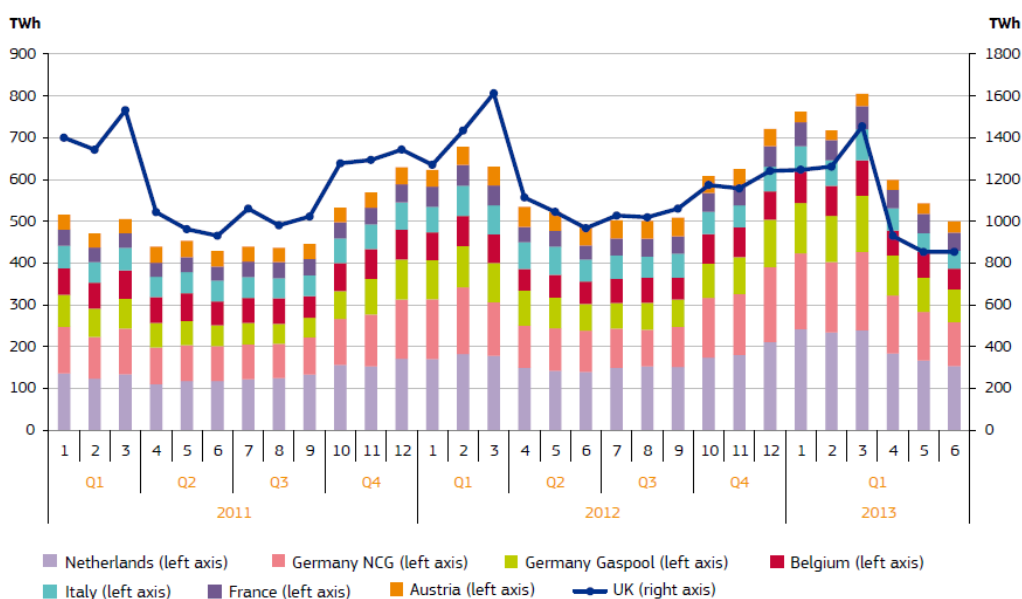
	Physical delivered volumes							
	NBP	Zeebrugge	TTF	PSV	PEG's	GASPOOL	CEGH	NCG
2003	52.5	10.2	1.3	0.1				
2004	53.2	10.6	2.3	1.0	0.2			
2005	53.7	8.4	3.8	2.0	2.7	0.3	0.7	
2006	60.6	8.6	5.9	4.8	3.8	0.8	4.7	0.1
2007	66.8	7.9	7.4	6.8	5.1	2.2	6.9	4.1
2008	66.6	9.1	18.7	7.7	6.6	4.4	5.2	14.4
2009	74.6	12.9	25.0	11.0	8.1	12.9	7.6	25.0
2010	95.8	16.7	31.3	21.5	8.7	29.6	10.9	31.3
2011	79.6	14.3	35.6	23.0	12.8	29.6	11.6	35.5
2012	88.2*	12.6	39.6	25.9	17.0	35.0	13.4	42.3
	Net traded/nominated volumes							
	NBP	Zeebrugge	TTF	PSV	PEG	GASPOOL	CEGH	NCG
2003	611.0	38.6	2.3	0.1				
2004	551.9	41.1	6.2	1.1	0.3			
2005	500.1	41.7	11.6	2.6	4.0	0.4	0.8	
2006	615.2	45.1	19.1	7.1	7.0	1.2	8.9	0.2
2007	902.6	40.2	27.6	11.5	11.1	4.8	17.7	6.6
2008	960.8	45.4	60.5	15.6	16.5	9.7	14.9	25.3
2009	1 016.1	64.9	73.6	23.5	23.1	28.6	22.8	56.0
2010	1 095.5	65.2	106.5	43.1	27.8	65.0	34.1	84.1
2011	1 137.2	69.3	151.7	57.7	39.8	75.8	39.2	108.5
2012	1 271.0	66.6	187.9	64.7	46.3	88.3	47.3	133.1

Source: IEA Medium Term Natural Gas Report 2013

According to the Quarterly Report on European Gas Markets published by the European Commission, total volumes traded on European gas hubs in the first half of 2013 remained stable compared to the first half of 2012 (10.530 TWh). There was only a slight decrease of 3,6%. The UK NBP hub traded 6.600 TWh, while the Dutch TTF hub traded 1.218 TWh and the two German hubs 1.520 TWh (622 TWh on Gaspool and 898 TWh on NCG) [20].

Relative to first quarter of 2012, the Dutch TTF and the two German hubs Gaspool and NCG increased their volumes by 27%, 23% and 22%, respectively, in the first quarter of 2013. On the other hand, traded volumes on NBP decreased by 11% (compared to the first quarter of 2012). During the first semester of 2013, total volumes physically delivered on European hubs increased by 5% in comparison with the same period in 2012. The hubs with the most notable increase in volumes physically delivered were Zeebrugge, Gaspool and NCG: +48%, +14% and +13%, respectively.

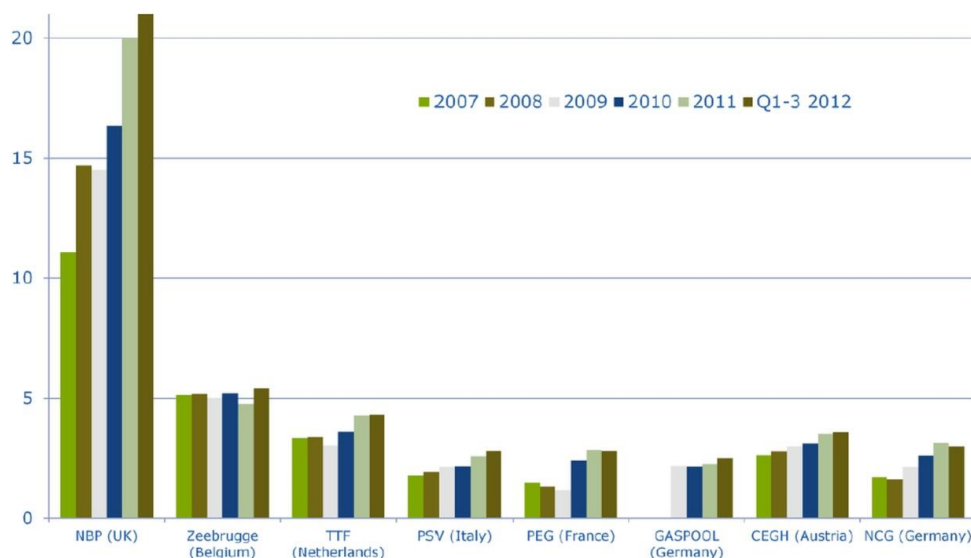
Figure 37. Traded volumes on European gas hubs.



Source: European Commission, Quarterly Report on European Gas Markets (Vol. 6)

The increase in physically delivered as well as traded volumes in European hubs is an indication that liquidity at most of the hubs is increasing. However, as the IEA points out, gas hub liquidity cannot be expressed in a single number. In addition to traded volumes, liquidity also measures features such as the churn ratio, the number of different products traded at a hub and the bid-offer spread. The NBP has by far the highest ratio between traded and delivered volume, with monthly churn ratios between 12 and 20. Continental European hubs generally demonstrate low churn ratios, between 2 and 7. In order to produce sustainable price signals, the churn ratio should be over 8, according to Jonathan Stern of the Oxford Institute of Energy Studies, while a hub is generally considered to be liquid if it has a churn rate of at least 10 to 15. As shown in the figure below, only the NBP meets this condition. However, as hub markets mature, churn ratios will grow.

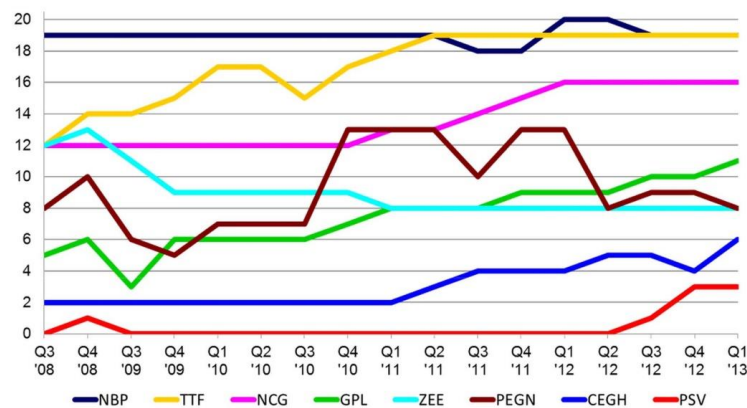
Figure 38. European gas hubs churn ratios.



Source: Sergei Komlev presentation, Gazprom Export

A particularly widely used liquidity indicator is also the ICIS Tradability Index, a figure published quarterly by ICIS-Heren which measures how narrow bid/offer spreads are across the trading curve [21]. It considers both the number of products that are traded on the market and the average spread between bid and offer prices for these products. From the figure below it is evident that the NBP and the TTF have the same performance in terms of tradability from the third quarter of 2012 and until the first quarter of 2013. The German NCG is the transition hub with the best tradability performance. The Zeebrugge hub and the North PEG do not present any promising results, while Gaspool and the CEGH show an upward trend. Finally, the Italian PSV is performing poorly.

Figure 39. ICIS Tradability Index.



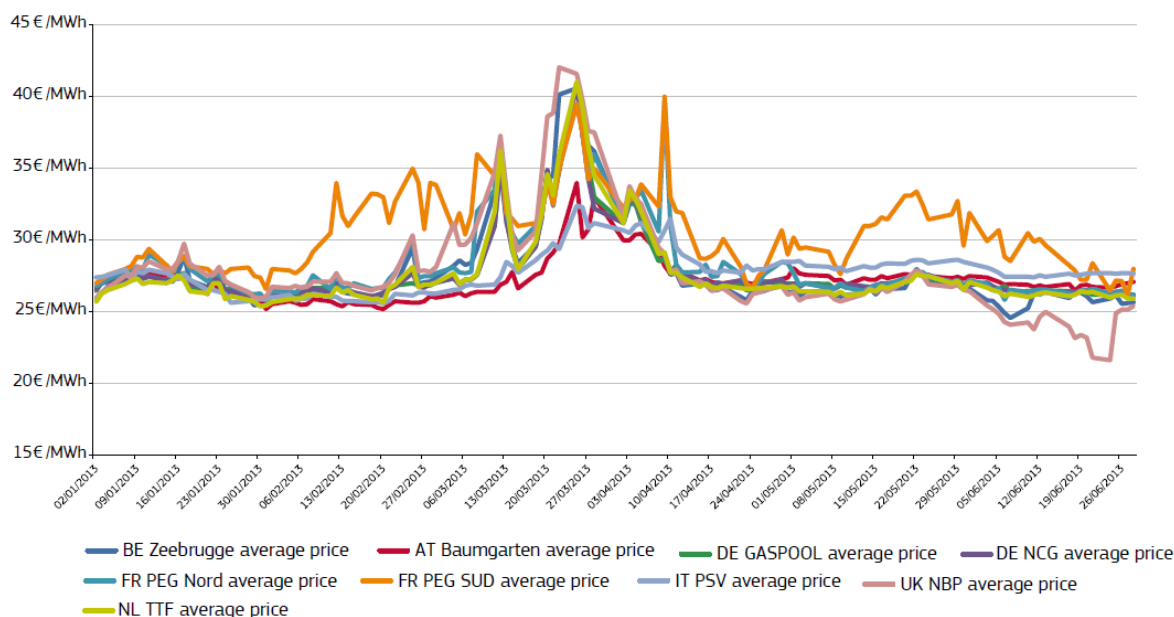
Source: Partick Heather

2.5. GAS PRICES ON EUROPEAN HUBS

According to the Quarterly Report on European Gas Markets published by the European Commission, during the last quarter of 2012 and in January 2013, the difference between the highest and the lowest day-ahead price was 1-2 Euros/MWh. This price convergence was interrupted by the cold spell in March 2013, as the difference between the highest and the lowest day-ahead price surpassed 6 Euros per MWh. The British NBP price even went above 40 Euros/MWh. After March, European gas hub prices started to converge again. However, in May 2013 the French PEGs and the Italian PSV exhibited price divergence from the rest of the European hubs, while in June the British NBP price decreased significantly, below 25 Euros/MWh, increasing once again the divergence between the highest and the lowest day-ahead price.

Over the next few years, natural gas prices are expected to stay close to current levels, and even decline as new gas sources become available. New sources of LNG as well as relatively stable oil prices will probably curb price rise.

Figure 40. Wholesale day-ahead gas prices on European gas hubs.



Source: European Commission, Quarterly Report on European Gas Markets (Vol. 6)

The next figure presents one-year forward prices on four hubs (TTF, NCG, NBP, Zeebrugge) during the first quarter of 2013. The prices of forward contracts were lower than the spot prices in March, which is usually associated with supply shortage (backwardation). In the following months one-year forward prices started moving higher than spot prices (contango), with minor differences between current and one-year forward prices. The hubs with the lowest forward prices are TTF and NCG.

Figure 41. One year forward gas prices on European gas hubs.



Source: European Commission, Quarterly Report on European Gas Markets (Vol. 6)

3. EUROPE'S INTERNAL ENERGY MARKET AND THE ROLE OF ENERGY EXCHANGES

3.1. THE INTERNAL ENERGY MARKET OF THE EUROPEAN UNION

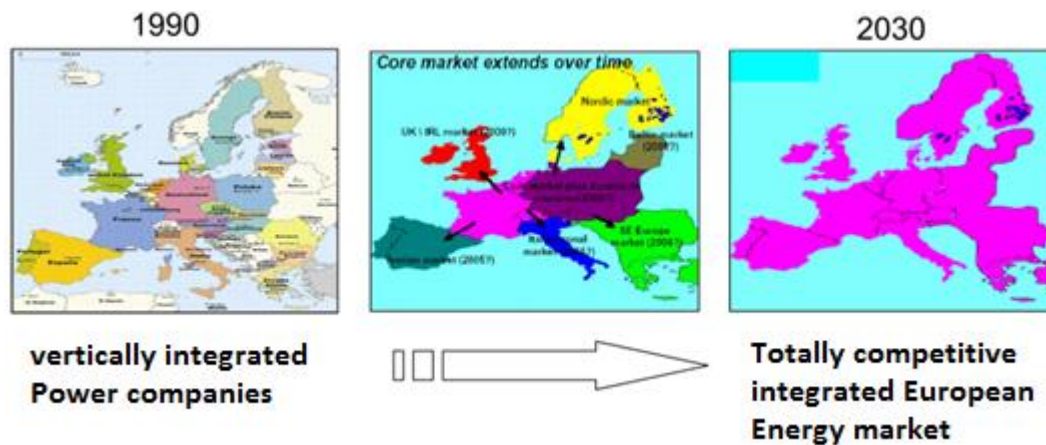
The objective of the present chapter is to present the basic framework and key developments in the EU internal energy market, in the process of integration and especially to present the energy exchanges which carry out a very important part of trading in the energy market. The principles of the internal market in electricity and natural gas, the new market operation model, and the regional initiatives in the energy market are presented briefly.

Regional initiatives primarily and originally being developed in the electricity market are an important step towards integration. Focusing on the internal electricity market, particular interest is drawn by the wholesale electricity market, which corresponds to the most significant part of the trading volume of electricity. In addition to the above, the aim of the chapter is to familiarize the reader with the role and the operation of power exchanges, as a core function of the wholesale market for electricity and natural gas, and also the role and operation of the Energy Transmission System Operator (TSO). Finally, a brief reference is made to the National Regulatory Authorities (NRAs) of energy, which constitute the controlling factor of the electricity market.

3.1.1. INTEGRATION OF THE INTERNAL ENERGY MARKET FOR ELECTRICITY & NATURAL GAS

The development of the internal energy market of the EU began in the late 90s. Currently, it is undergoing the 3rd stage of integration and development. The third energy package, which was adopted in 2009, defines today the formation, development and evolution of the internal electricity and natural gas market in the EU.

Picture 8. Integration stages of the European Energy markets.



3.1.1.1. FIRST LEGISLATIVE PACKAGE ON THE INTERNAL ENERGY MARKET

In 1992, the European Commission put forward proposals to the Council on common rules for the internal market in electricity and natural gas. As a result, the first legislative package for the liberalization of the European energy market was introduced.

Regarding the electricity market, the Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity was adopted, followed by the related set regarding the natural gas, i.e. Directive 98/30/EC European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas (OJ L 204, 21.7.1998).

3.1.1.2. SECOND LEGISLATIVE PACKAGE ON THE INTERNAL ENERGY MARKET

In 2003, the obstacles identified in the comparative reports of the European Commission, led to the adoption of the second package of measures for the liberalization of the European energy market.

Regarding the electricity market, the Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC was issued. Alongside, the Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity was adopted.

The new Directive extended the liberalization of the electricity market to all non-household customers by July 2004 and to all customers by July 2007. Furthermore, the new Directive includes measures for the legal separation of the management of the transmission and distribution of electricity from the generation and supply activities, enhances the role of Energy Regulators of the Member States, requires the publication of charges for the use of networks, enhances utility services particularly for vulnerable consumers and establishes measures for the security of supply.

The new Directive is accompanied by the Regulation on cross-border trade (1228/2003). The Regulation establishes common rules for cross-border electricity trade. The guidelines for implementing the Regulations for the compensation of managers of networks that undergo

transits of electricity, for the harmonization of national charges for transmission and the distribution of capacity of interconnections will be adopted by the procedure laid down in the Regulation.

For the regulation of the gas market the Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas was adopted along with the Regulation (EC) No 1775/2005 of the European Parliament and of the Council of 28 September 2005 on conditions for access to the natural gas transmission networks.

Moreover, the ERGEG was established with the Decision 2003/796/EC of 11 November 2003 on establishing the European Regulators Group for Electricity and Gas.

Furthermore, the 2004 Gas Security Directive has been intended to improve security of supply in the natural gas sector.

3.1.1.3. THIRD LEGISLATIVE PACKAGE ON THE INTERNAL ENERGY MARKET

The 3rd Energy Package provides for the implementation of the Single European Market Model, which provides for the creation of the internal market, which will benefit consumers through equitable access to energy resources of all countries.

The third package includes:

- **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.
- **Regulation (EC) No 714/2009** of the European Parliament and of 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 the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005.

The **basic settings of the third package** include:

- Effective separation of the transmission and distribution activities from the activities of generation and supply.
- Promoting competition, regional electricity and natural gas markets, in order to integrate the internal energy market.
- Increased transparency and better functioning of the retail market/consumer protection and establishing obligations for the supply of utilities services/fighting energy poverty and implementation of intelligent measuring systems.
- Each consumer participates in the formation of the price of electricity charged and adapts its consumption characteristics by providing opportunities for load management, thus streamlining the consumption and promoting energy saving.
- Strengthening solidarity and regional cooperation between Member States to ensure security of supply.

- Establishment of the Agency for the effective cooperation between national regulators, coverage of the regulatory gap at the European level and the promotion of the effective functioning of the internal energy market.
- Establish mandatory cooperation between Transmission System Operators (ENTSOs: ENTSO-E/ENTSO-G) aiming to harmonize all rules governing the transmission of energy in Europe, and for coordinated planning of infrastructure investments of cross-border interest.
- Strengthening of the Independent Regulators for effective regulatory oversight.

As stated in Directive 2009/72/EC, the objective of the internal market in natural gas is to deliver real choice for all consumers of the European Union, be they citizens or businesses, new business opportunities and more cross-border trade, so as to achieve efficiency gains, competitive prices, and higher standards of service, and to contribute to security of supply and sustainability.

Directive 2009/72/EC of the European Parliament and the Council is the heart of the third energy package. This directive involves adopting common rules for the internal market in electricity and natural gas and revoking previous arrangements. This Directive establishes common rules for the transmission, distribution, supply and storage of natural gas. It lays down the rules relating to the organization and functioning of the natural gas sector, access to the market, the criteria and procedures applicable to the granting of authorizations for transmission, distribution, supply and storage of natural gas and the operation of systems. The rules established by this Directive for natural gas, including LNG, shall also apply in a non-discriminatory way to biogas and gas from biomass or other types of gas in so far as such gases can technically and safely be injected into, and transported through, the natural gas system.

Among the provisions of the directive, it is stated that Member States are responsible for monitoring security of supply issues and in particular those related to the balance of supply and demand on the national market, available supplies, maintenance of the networks and the measures to be taken in the event of supply problems. Regional or international cooperation may be put in place to ensure security of supply.

It is also provided that Member States shall ensure the integration of national markets at one or more regional levels, as a first step towards the integration of a fully liberalized internal market. The gas islands in isolated regions shall also be integrated. In this context, the national regulatory authorities shall cooperate with the Agency for the Cooperation of Energy Regulators.

Unbundling

Starting from 3 March 2012, Member States were directed to unbundle transmission systems and transmission system operators and to designate one or more storage and LNG system operators responsible for:

- operating, maintaining and developing transmission systems, storage and/or LNG facilities with due regard to the environment;
- ensuring non-discrimination between system users;
- providing information to any other transmission system operator, any other storage system operator, any other LNG system operator and/or any distribution system operator to ensure the interconnection of the transmission and storage of natural gas;
- providing system users with the information they need to access the system.

Transmission system operators have to build sufficient cross-border capacity to integrate the European transmission infrastructure. Every year, they submit to the regulatory authority a ten-year network development plan indicating the main infrastructure that needs to be built or modernized as well as the investments to be executed over the next ten years.

Distribution and supply

Member States designate distribution system operators or require undertakings from companies that own or are responsible for distribution systems to act in such roles.

Distribution system operators are mainly responsible for:

- ensuring the long-term capacity of the system in terms of the distribution of gas, operation, maintenance, development and environmental protection;
- ensuring transparency with respect to system users;
- providing system users with information;
- covering energy losses and maintaining reserve capacity.

The distribution system operator is independent in legal terms from other activities not relating to distribution.

Distribution systems responsible for distributing natural gas within a geographically confined industrial, commercial or shared services site may be classified by the competent authorities as closed distribution systems. On this basis, they may be exempted from the requirement to have their tariffs, or the methodologies underlying their calculation, approved in advance.

Organization of access to the system

Member States or the competent regulatory authorities define the conditions for access to storage facilities and linepack. They take measures to ensure that eligible customers can obtain access to upstream pipeline networks. Moreover, they organize a system of third party access to transmission and distribution systems.

Natural gas system operators may refuse access to the system on the basis of lack of capacity or where access to the system would compromise the performance of their public service obligations. Substantiated reasons shall be given for any such a refusal.

3.1.1.3.1. REGULATION (EC) NO 715/2009 ON CONDITIONS FOR ACCESS TO THE NATURAL GAS TRANSMISSION NETWORKS

This Regulation lays down rules for natural gas transmission networks, gas storage and liquefied natural gas (LNG) facilities. It concerns access to infrastructures, particularly by determining the establishment of tariffs (solely for access to networks), services to be offered, allocation of capacity, transparency and balancing of the network.

Certification of transmission system operators

National regulatory authorities send notification of decisions relating to the certification of a transmission system operator to the European Commission. The Commission then has a period of two months to deliver its opinion to the national regulatory authority. The authority then adopts the final decision concerning the certification of the transmission system operator.

European Network of Transmission System Operators (ENTSO) for gas

ENTSOG's role is to manage the development process and fulfil the TSOs' obligation to cooperate at European level as defined by Gas Regulation (EC) 715/2009. Established on a non-profit basis in December 2009, ENTSOG works closely with the European Commission, the new European regulatory agency ACER, and a wide variety of stakeholders to fulfil its mandate.

The ENTSO for Gas is responsible for adopting:

- common network operation tools;
- a ten-year network development plan;
- recommendations relating to the coordination of technical cooperation between Community transmission system operators;
- an annual work programme;
- an annual report;
- annual summer and winter supply outlooks.

Costs and tariffs

The regulatory authorities determine tariffs or methodologies for their calculation. Member States may take decisions relating to tariffs such as fixing auction arrangements.

Third-party access services

Transmission system operators offer their services equitably to all network users on a rolling basis in the long and short term.

LNG and storage facility operators must also offer their services according to the procedure described above and make them compatible with the use of interconnected gas transport networks.

Allocation of capacity and congestion management

All market participants must have access to maximum network capacity as well as storage and LNG facilities.

Infrastructure operators shall implement and publish non-discriminatory and transparent congestion-management procedures which facilitate cross-border exchanges in gas on a non-discriminatory basis.

3.1.1.3.2. REGULATION (EC) NO 713/2009 ESTABLISHING AN AGENCY FOR THE COOPERATION OF ENERGY REGULATORS

The third energy package is completed with Regulation (EC) No 713/2009 of the European Parliament and the Council, which established the Agency for the Cooperation of Energy Regulators (ACER). The purpose of the Agency is to coordinate and assist National Regulatory Authorities (NRAs) in their work on the establishment of common rules for the internal market in electricity and natural gas, as well as to exercise, at the European level, the responsibilities that regulatory authorities have on the national level. Furthermore, ACER is responsible for developing specific instructions (Framework Guidelines), concerning the operation of the power system, balancing the power system and other related issues, in light of the legislative provisions of the third energy package. These Framework Guidelines would be then the basis on which to develop technical guidance (Network Codes).

3.1.1.3.3. THE HIGHLIGHTS OF THE 3RD ENERGY PACKAGE

The **highlights of the third energy package** include:

- **Separation of the Transmission & Distribution System**
 - **The problem:** The legal and functional unbundling of network operators that were vertically connected with supply and production companies proved to be inadequate to ensure third party access, to prevent the creation of a dominant market position, the distortion of competition and determining and implementing the necessary investments.
 - **The option of ownership unbundling:** the Owner and the Operator of the transmission system may not directly or indirectly control producing and/or supplying companies (or be controlled by them).
 - Parallel participation in the System Operator and a production and/or supply company is permissible only if there is no issue of control.
 - **Independent System Operator (ISO) standard**
 - ➔ **Provision:** Choosing the Independent System Operator standard, provides the ability of vertically integrated companies to retain ownership of the system, without controlling its operation.

- **Consequence:** The new System Operator (ISO) - certified under stringent conditions and subject to constant supervision - for autonomous trading and investment decisions
- **Reception:** Choosing the Independent System Operator standard did not prove popular among Member States.
- **Independent Transmission Operator (ITO) Standard**
 - The ownership of the assets of the transmission system, as well as the authority for the operation of the system is transferred to a new company (ITO), which remains as member of the group of companies of the parent company.
 - The new company must meet strict criteria of independence and autonomy, especially with respect to particular assets, personnel and economic operation.
- **Strengthening of national regulators**
 - **The Problem:** Inhomogeneous authorities of the regulatory authorities in the EU and the problematic regulation of the internal market
 - **The Solution:** Strengthen the independence and powers of national regulatory authorities, including powers to regional / community.
 - Internal Function
 - Independence from the executive and economic interests particularly in the energy sector,
 - Financial Independence
 - **Members:** a minimum term of five to seven at most years, renewable once
 - Responsibilities on cross border issues. The development of regional markets and the removal of barriers to cross-border trading is introduced as an objective for the Regulators. For this purpose the following are established:
 - Cooperation with Regulatory Authorities of other member states and the ACER (the Regulatory Council in which they participate with voting rights)
 - The obligation for compliance and implementation of the decisions of the Commission and ACER
 - The obligation to ensure the compatibility of the national program of investment in transmission infrastructure with the Community-wide investment program.
 - Responsibilities on national Level
 - Certify that the institution proposed as Operator meets the separation criteria under Directives and Regulations. The decision is notified to the European Commission, which may consult the ACER.
 - They conduct constant supervision on the validity of the certification criteria
 - The powers of preventive and repressive control are enhanced. Regulators impose appropriate measures / binding decisions for businesses, as well as penalties and especially for the well-functioning of the competition in the energy market, the emergence of restrictive practices, the operation of the Operators, etc.

- **Retail Market and Consumer Protection**
 - Previous Regulatory Framework: Emphasis on wholesale market
 - 3rd Package: Grid Provisions for Consumer Protection/Focus on the Organization and Functioning of the retail market to achieve:
 - ➔ Provision of upgraded Services
 - ➔ Effective exercise of the right of vendor selection
 - Regulatory Oversight:
 - ➔ Effective protection of consumers is the objective, in particular for those belonging to the category of Vulnerable Consumers
 - ➔ The role, powers and responsibilities of Operators and Vendors towards the Customer will be clearly defined and disclosed. Review by regulators and other competent authorities.
 - ➔ The Regulators decide or approve standards for the quality of the service and verify compliance.
 - ➔ Vendors can supply customers anywhere in the EU
 - Each Member – state defines:
 - ➔ "Contact Points" for continuously informing consumers about their rights, current legislation, and the methods and procedures for resolving disputes.
 - ➔ Independent Energy Ombudsman for quick and effective response to complaints and out of court settlements.
 - ➔ Residential Customers and Small Businesses have the right to enjoy Universal Service (including the possibility for setting Supplier of last Resort).
- **The European regulatory authority: ACER**
 - The establishment of the Agency for the Cooperation of Energy Regulators (ACER)
 - o General Responsibilities
 - ➔ Monitors the functioning of the internal market for electricity and gas and the compliance with the relevant European legislation by Member States.
 - ➔ Publishes opinions and recommendations addressed to the European Parliament, the European Council, the European Commission, regulators and transmission system Operators for electricity and natural gas.
 - ➔ In addition to supervisory, advisory and consultative powers, the ACER has decision-making powers.
 - ➔ Takes individual decisions in specific cases defined.
 - ➔ Determines the regulatory framework governing the interconnections between two or more Member States.
 - ➔ Exercises decisive authority in the case of cross-border investments (exemption from liability for third party access) and establishes the regulatory framework for cross-border trade.
 - ➔ Specifies the Independent Operator (ISO).
 - ➔ Resolves cross-border disputes.
 - ➔ Issues an opinion on the annual agenda of ENTSO, the codes of operation and the 10-year development plan of transmission systems.

- Monitors the implementation of the 10-year development plan and monitors any deviations during the implementation, making recommendations to managers and the national regulatory authorities.
- Monitors the regional cooperation of Operators.
- **ENTSO: Compounds of Transmission System Operators for Electricity and Natural Gas**
 - The purpose of ENTSO is to become and remain the focal point for all European, technical, market and policy issues related to TSOs, interfacing with the energy users, EU institutions, regulators and national governments.
 - ENTSO's work products contribute to security of supply, a seamless, pan-European internal energy market, a secure integration of renewable resources and a reliable future-oriented grid, adequate to energy policy goals.
- **Regional Cooperation**
 - Although there is no specific reference to the already -established regulatory framework for regional cooperation (EREG Regional Initiatives), there is a clear reference to the need for cross-border cooperation between regulators and administrators, while the Commission has stated that it does not wish to inhibit the action of regional initiatives.
 - Benchmark for cooperation is the geographical areas defined in the Regulations and provides for the possibility that cooperation may cover other geographical areas as well
 - ACER Regulation: ACER will take account of the conclusions of the work of regional cooperation in decision making.
 - Individual manifestations of Regional Cooperation
 - (i) Mechanisms for Regional Cooperation - regional solidarity mechanisms -
(Example: coordinated regional programs of emergency)
 - (ii) International regional cooperation
 - (iii) Regional Co-Trustees (with expressed obligation, among others, to elaborate regional development programs).
 - Conclusion: coordinating regional and national approaches during the transition to a single European energy market remains a priority.

3.1.2. REGIONAL INITIATIVES

3.1.2.1. ELECTRICITY MARKET

The Regional Initiatives in the electricity sector created in the spring of 2006 by ERGEG⁸ refer to the creation of regional blocs aimed at coordination, harmonization and integration of electricity markets at regional level, initially, as an intermediate step for the realization of the common internal market in electricity. Therefore, regional initiatives are regarded as the first important step towards the integration of national electricity markets of EU (ERGEG 2006a and ERGEG 2006b).

Picture 9. Baltic Regional Initiative (Estonia, Lithuania, Latvia)



Picture 10. Regional Initiative of Central and Western Europe (CWE) (France, Belgium, Germany, Holland, Luxembourg)



Picture 11. Regional Initiative of Central and Eastern Europe (CEE) (Germany, Poland, Austria, Czech Republic, Hungary, Slovakia, Slovenia)



Picture 12. Regional Initiative of Northern Europe (Finland, Norway, Sweden, Denmark, Germany, Poland)



⁸ European Regulatory Group for Electricity and Gas - ERGEG

Picture 13. Regional Initiative Central and Southern Europe (CSE) (France, Germany, Italy, Austria, Greece, Slovenia)



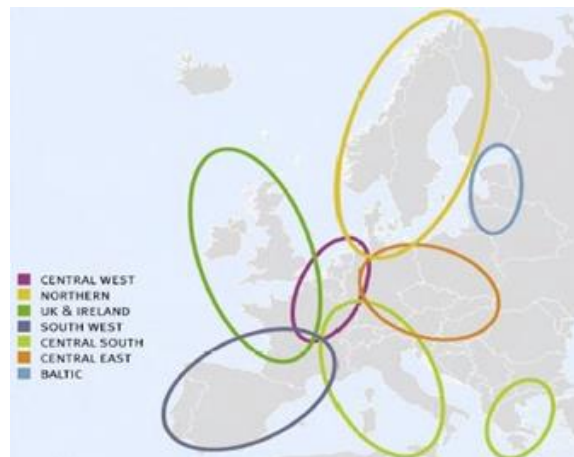
Picture 14. Regional Initiative of Southern and Western Europe (SWE) (Spain, Portugal, France)



Picture 15. Regional Initiative France – UK -Ireland



Picture 16. Overall presentation of Regional Initiatives for the integration of electricity markets



The regional initiatives mentioned above are currently in different stages of coordination, harmonization and integration. In this context, the role of regional initiatives is important to promote good practices and practical ways to test the proposed solutions concerning the electricity market. Additionally, they serve as a platform for monitoring and compliance of Member States with the provisions of regulations, directives and framework of network codes of the EU institutions. At the same time, they are the vehicle for improving the coordination, harmonization and integration of different national electricity markets.

3.1.2.2. NATURAL GAS MARKET

The European gas market has started to take shape following the publication of the 3rd Package and the subsequent development of Framework Guidelines and Network Codes by the Agency and ENTSOG, respectively. The first Network Code in gas was adopted in 2013, in the area of capacity allocation mechanisms (CAM), and a second one on balancing received the favourable opinion from the Gas Committee in the fall of 2013. Two more Network Codes, on interoperability and data exchange and harmonised transmission tariff structures, are expected to be completed or adopted in the course of 2014.

South South-East region

The South South-East (SSE) region comprises Austria, Bulgaria, Croatia (which joined in July 2013), Cyprus, Czech Republic, Hungary, Greece, Italy, Poland, Romania, Slovakia and Slovenia.

In 2013, the areas of work and main achievements in the region were the following:

- **Market integration:** three projects are included in the regional Work Plan 2011-2014 within this area of work, with the respective goals of establishing a cross-border Regional Balancing Platform by the Austrian Central-European Gas Hub (CEGH), analysing the implementation of the GTM in the region by creating a Central-Eastern European Trading Region (CEETR project) and setting up a roadmap for the creation of a common regional gas market in the Visegrad Four Region (V4 - Poland, Czech Republic, Slovakia and Hungary).

The main **achievements** in these projects included: (i) the completion of the first phase of the CEETR project, through the publication of the analysis of the macroeconomic benefits of implementing different models for balancing and trading zones as well as of the main principles under which a trading region could work; and (ii) the development of the Roadmap for V4 integration, which was endorsed by the V4 Prime Ministers in June 2013 and entered its implementation stage in the second half of 2013. The involved NRAs will need to coordinate and ensure the compatibility between the V4 and CEETR projects.

- **Interoperability:** the region aims to adopt common standards in order to improve system interoperability, based on the EASEE-gas (European Association for the Streamlining of Energy Exchange - gas) common business practices (CBPs), regarding aspects such as the units for measuring gas and a harmonised definition of the gas day. The possibilities for an early Network Code implementation with regard to interoperability will also be explored. In addition, the other priority in the region is to achieve sub-regional integration and harmonisation of procedures, in particular on the route from Slovakia to Germany and back to Slovakia or Austria (Baumgarten).

3.1.3. NATIONAL REGULATORY AUTHORITIES

National Regulatory Authorities (NRAs) are national, independent, supervisory structures, with responsibility for the regulation of energy markets and the promotion of cooperation at European level. Articles 35 to 40 of Directive 2009/72/EC of the European Parliament and the Council define the role, independence, purpose and powers of national regulators.

Among others, the national regulatory authorities are responsible for:

- Promoting, together with other legal entities, a competitive, secure and open energy market at national and European level.
- Correcting and approving of user fees for transmission and distribution, as well as the methodology of calculation.
- Ensuring compliance of TSO and DSO with the provisions of the European legislation.
- The implementation of European legislation and other legally binding decisions of ACER.
- Monitoring and evaluation of investment and development projects of TSOs in relationship with the development of the transmission network.
- Monitoring the efficiency of market opening and competition at both the wholesale market and retail market.

3.1.4. ENERGY EXCHANGES

Most Energy exchanges in Europe have been established in order to become Market operators of the Power market of the relevant country that they operate in. Gradually they have expanded their activities to cover natural gas, carbon certificates, coal and other products.

Energy exchanges offer a trading platform accessible by members only for submitting bids for buying and selling power or natural gas. They organize markets that are optional and anonymous and accessible to all participants satisfying admission requirements. The main objective of energy exchanges is to ensure a transparent and reliable wholesale price formation mechanism on the market by matching supply and demand at a fair price to ensure that the trades done at the exchange are finally delivered and paid.

Energy Exchanges operate within the wholesale market for electricity and natural gas and constitute the Market Operator. This is the place where transactions take place. These transactions refer to the signing of contracts for purchase or sale of electricity and natural gas, according to the market mechanism. Therefore, an energy exchange is the place where the price of electricity and gas is determined. In this context, an energy exchange is not particularly different from a common commodity market. The difference lies in the fact that the product that is available for trading is electricity and natural gas.

The trading parties in an energy exchange can be power and gas generators, power and natural gas suppliers, large end users, traders and brokers. The energy exchange guarantees transparency of procedures, impartial and prompt execution of orders of counterparties, secure clearing, payment and settlement of contracts, as well as anonymity of transactions.

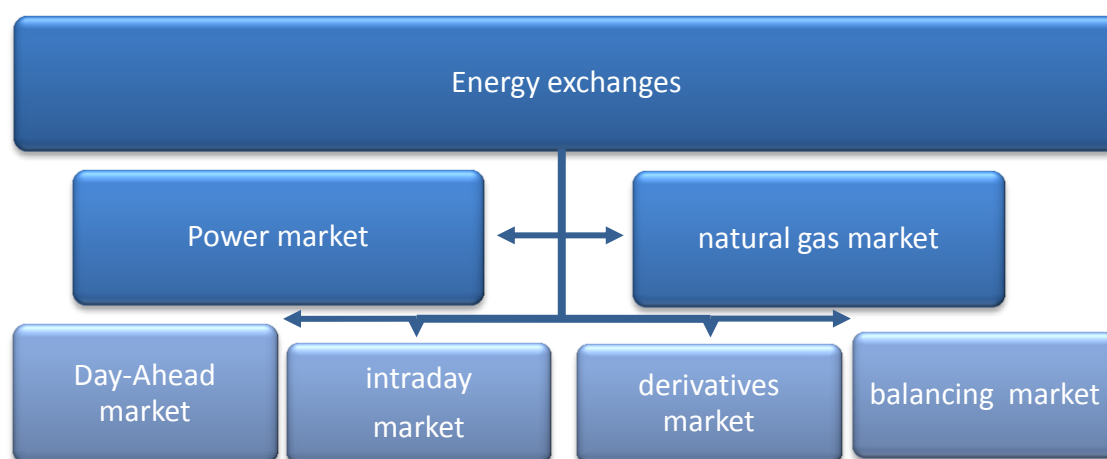
In an energy exchange, for example, the trading parties submit purchase or selling orders for electricity to the trading system. Producers submit sales orders, for the sale of the electricity that they produce to suppliers, large consumers, traders, or TSOs, when electricity is needed to balance the system. Suppliers submit purchase orders in order to buy electricity from

producers or traders for their customers (end users). Brokers are also active as trading parties, in order to promote bilateral contracts for purchase and sale of electricity between stakeholders. Similarly, the same applies for the natural gas market.

In an energy exchange four main markets exist, according to the predictions of the model of the internal electricity and natural gas markets. As shown in Figure 42, these are the Day-Ahead Market, the Intraday market, derivatives market and the balancing market. The aforementioned markets currently exist and operate in different energy exchanges in a different range of application and integration.

Correspondingly, Energy exchanges that trade natural gas support the same market structure for the Natural Gas market.

Figure 42. Market structure of energy exchanges.



3.2. ENERGY EXCHANGE TRADED PRODUCTS

As mentioned earlier most energy exchanges in Europe have started their operation in the electricity market and have gradually launched natural gas markets. The market structure and the products traded in the electricity and natural gas markets are quite similar. Most products traded in various exchanges have quite similar characteristics. The following energy products may be found in Energy Exchanges across Europe.

3.2.1. POWER MARKET PRODUCTS

3.2.1.1. SPOT MARKET CONTRACTS

3.2.1.1.1. SPOT – DAY AHEAD

A physical market, where prices and quantities are determined by supply and demand, while prices and total trading volumes are disclosed. The contracts traded on the spot market

involve the delivery and receipt of power on the day following the trading day (day ahead). Trading is usually concluded at noon and deliveries take place from midnight to 24 hours ahead. The producers and consumers of energy submit their tenders on the market from 12 to 36 hours before delivery, indicating the amount of electricity supplied or demanded and the corresponding price. Then, for each hour, the price cleared in the market is determined in the energy exchange. In principle, all energy producers and consumers can trade in the energy exchange, but in reality, only large consumers (distribution companies, trading companies and large industries) and producers operating in the market trade in, while smaller businesses create marketing cooperatives (as in the case of wind turbines), or agree with larger businesses so that they can act on their behalf .

This market mainly concerns:

- Electricity producing companies
- Intermediaries of Electricity trading
- Electricity consumers
- Wholesale electricity trading companies
- Brokers and commodities brokerage companies.

3.2.1.1.2. SPOT – INTRADAY DAILY

Quite long time lags exist between the closing of trading on the day-ahead market, and the settlement of the energy market. The Intraday market therefore acts as an "intermediate market", where the participants of the day-ahead market may trade bilaterally. Usually, the product negotiated is a contract with duration of one hour of supply of electricity. The prices determined in this market are based on supply and demand.

Intraday trading is needed due to imbalances that are generated by sudden fluctuations in total production or consumption in the respective units of production and consumption. The variations are particularly likely in the production of wind energy, since it is difficult to forecast the exact production more than a few hours earlier.

The intraday market aims to help increase competition by offering additional trading opportunities, as the time of delivery is approaching. Thus, unexpected fluctuations in supply and/or demand can be solved through changes in prices, according to the available information used by market participants to assess their positions on the market.

In the Elbas market of Nord Pool, for example, electricity may be traded up to 1 hour prior to delivery, whereas in the United Kingdom a group of markets operate in which participants can correct previously underwriting positions via so-called NETA bilateral contracts. In this case, the transactions made during the three and a half hours before delivery.

Most of these markets function with a continuous trading system, and some through the auction system, as in the case of Spain.

3.2.1.1.3. SPOT – INTRADAY HOURLY – BALANCING SERVICES/REAL-TIME MARKET

To balance power generation to load at any time during real-time operations, system operators use a balancing or real-time market. After the closure of the spot market, participants can submit bids that specify the prices they require (offer) to increase their generation or decrease their consumption (decrease their generation or increase their consumption) for a specific volume immediately.

Such balancing services (also referred to as ancillary services), for which competitive market mechanisms are increasingly sought, cover the provision of a number of services, for instance voltage control, frequency response and reactive power support.

Some grid operators in Europe have started to procure the capacities and energy necessary to provide ancillary services from other companies via published auctions. This currently still fragmented market is expected to become increasingly integrated in the near future.

Therefore, especially the tertiary and minute-reserve market could turn into a liquid wholesale market, as there are many power producers who are able to provide those services and to meet the existing substantial needs of both the grid operators and the suppliers in this direction. Furthermore, as there is no need to make additional investments in technical equipment, the market access barrier is small.

CHP plants could basically provide these services, too, given that sufficient capacity is being held in reserve for these purposes when optimizing the unit commitment and/or dispatching. The authority responsible for the bidding at the market has – sometimes simultaneously – to find the best bidding strategy for electricity, reserve capacity, heat, and possibly fuel in order to maximize profits.

3.2.1.2. DERIVATIVES

Financial contracts used to hedge price changes and for risk management. The contracts have a time horizon of up to six years, covering daily, weekly, monthly, quarterly and annual contracts. The system price calculated in the spot market is used as a reference value (underlying) for the derivatives market.

No physical delivery is provided for financial electricity contracts. The cash settlement takes place throughout the course of trading – and/or maturity, commencing on the expiration date of each contract, depending on whether the product is a futures or forward. Technical terms, such as traffic congestion and network access are not taken into account when negotiating these contracts. However, buyers and sellers can with the help of derivative financial contracts of the energy market manage risks related to prices in the underlying market.

3.2.1.2.1. FUTURES - FORWARDS

Futures and forwards are traded on most energy exchanges in Europe, usually as contracts involving cash settlement, while there is a great variety of available maturities which are weekly, monthly, quarterly, and yearly.

A forward contract with physical delivery for electrical power supply (power derivative) is a contract in which the seller (issuer of the contract) is committing to deliver electrical power on a specific date (term) in the future, at a specified price and the buyer (buyer of the contract) commits to purchase electrical power on a specified date and at a specified price.

Forward contracts with physical delivery allow setting the price of electrical power over a longer time horizon, which creates significant price incentives for investors planning to build new generation capacity. They allow power dealers and large consumers to forecast the prices and optimize their costs of buying/selling electrical power.

One of the key characteristics, which differentiate a futures contract from a forward contract, is the fact that, in the former, the gains and losses resulting from price fluctuation, during the trading phase, are settled on a daily basis while in the latter this only occurs during the contract delivery period and on a monthly basis.

Futures are also distinguished based on the period of time during each day for which delivery of electricity is agreed. The available options refer to the base load, meaning the delivery of power for 24 hours per day, the peak hours and the off peak hours. The peak load time span varies in each market, depending on the needs of the respective network of the reference country. Usually it refers to a period of 8:00 to 20:00.

Settlement of futures contracts involves both a daily mark-to-market settlement and a final spot reference cash settlement, after the contract reaches its expiry date. Mark-to-market settlement covers profit or loss from day-to-day changes in the daily closing price of each contract. Final settlement, which begins at delivery, covers the difference between the final closing price of the futures contract and the system price in the delivery period. Throughout the final settlement period, which starts on the expiry date, the member is credited/debited an amount equal to the difference between the spot market price and the futures contracts final closing price.

Execution of the contract (physical delivery)

On the day dated one day before the delivery date (after closure of the trading session) the contract is being reduced by the amount of energy subject to delivery on particular hours of the delivery date. Execution of a forward contract means physical delivery of the energy, in compliance with the scheduled period of delivery, depending on the type of contract, in a breakdown adequate to the daily energy batches, corresponding to the following product:

"number of hours during the day (depending on the type of contract) x number of contracts"

As a result, in the execution period, forward contracts are converted to physical contracts (so-called reduced contracts) with a volume decreasing daily by the daily volume of energy delivery.

3.2.1.2.2. OPTIONS

Similar to the financial options, options in the energy exchange give the right to the owner to purchase electricity (call option) or sell (put option) a certain quantity of electricity at a specified future date (or time span) at a predetermined exercise price.

- The buyer of a call option (call) is entitled to receive a long position in the corresponding Base Month Future at the exercise price of the option on the last trading day.
- The seller of the call option (call) receives a short position in the corresponding Base Month Future after the call option is exercised and assigned at the exercise price on the last trading day.
- The buyer of a put option (put) is entitled to receive a short position in the corresponding Base Month Future at the exercise price of the option on the last trading day.
- The seller of the put option (put) receives a long position in the corresponding Base Month Future at the exercise price after the put option is exercised and assigned on the last trading day.

The buyer of an option contract is obliged to pay the price for the purchase of the right of option (option premium) on the Business Day after the purchase. The premium is credited to the seller of the option on the same day.

Power exchange options are usually European type, i.e. the option can only be exercised on the last trading day.

Maturities are usually Month, Quarter, Season and Year.

The option can only be exercised on the last trading day. Said exercise is carried out by means of an entry into the system between 08:00 a.m. and 03:00 p.m. (Exercise Period) on the last trading day. On the last trading day the exchange determines the intraday market value of the underlying and publishes it in due time before the end of the Exercise Period.

3.2.2. NATURAL GAS

3.2.2.1. SPOT MARKET CONTRACTS

Similarly to the electricity market, the spot market for natural gas is separated in the Day Ahead, the Intraday and the balancing market.

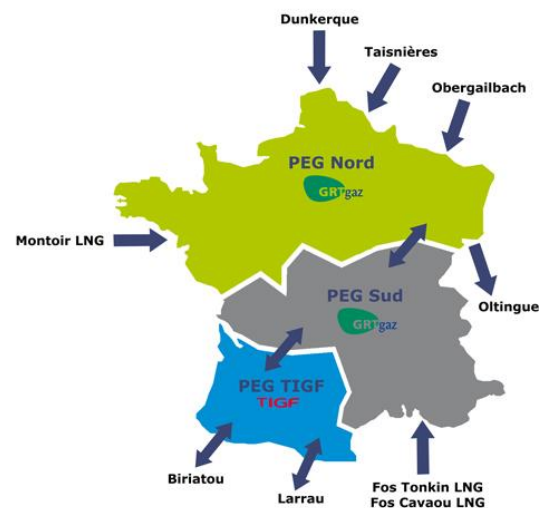
Contracts for the physical delivery and receipt of gas are being traded in the spot market of Energy exchanges around the clock (24/7) and on all calendar days of the year. The spot contracts for natural gas are block contracts for the delivery and/or supply of gas at a constant rate of delivery for daily load (Daily Natural Gas Contracts) or weekend (Natural Gas weekend Contracts), as well as the variable delivery capacity on an intraday basis (Intraday Natural Gas Contracts).

Underlying for the trading is gas of specific standards or quality, that is either the H-gas (High calorific natural gas), which is the most common product, or the L-gas (Low calorific natural gas).

Delivery is made at a trading hub at predetermined reference locations. In Germany, for example, those areas are the NetConnect Germany GmbH & Co KG (NCG-Contracts Natural Gas), the GASPOOL Balancing Services GmbH (GASPOOL Contracts Natural Gas) exclusively in H-Gas quality. In the Dutch Gastransport Services BV the corresponding area is the Dutch Title Transfer Facility (TTF natural Gas Futures) in grades of H-Gas and L-Gas gas.

Similarly, the French territory is divided into three market areas which are simultaneously interconnected with neighboring countries.

Picture 17. The natural gas territories in France.



Delivery Periods and Delivery Time

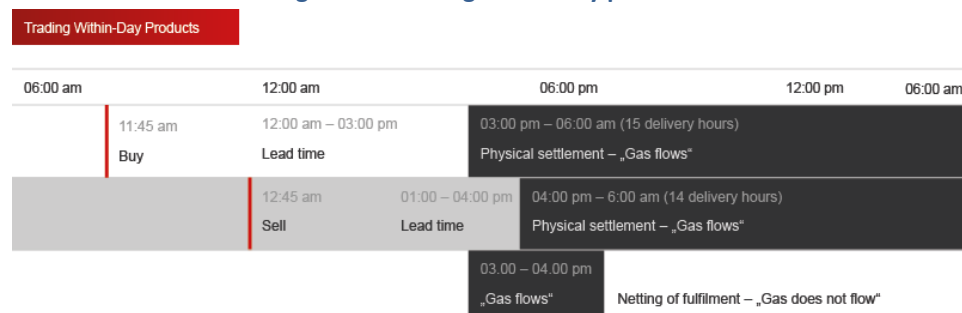
The delivery periods with the respective delivery times for the respective market area can be:

- **Within Day:** the tradable delivery period is calculated from the time of the beginning of delivery (the next full hour after the conclusion of the trade plus 3 full hours of preliminary lead time) and the end of delivery at 06:00⁹ of the following calendar day;
- **Day:** delivery time from 06:00* of any given delivery day until 06:00* of the following calendar day;
- **Weekend:** delivery time from 06:00* of the first delivery day of the delivery period (generally Saturday) until 06:00* of the first calendar day after of the end of the delivery period (generally Monday). The delivery period comprises also delivery days before or after a weekend, which are holidays in Great Britain.

⁹ 6:00 is used as beginning of the day reference time in most exchanges.

Trading of the Within-Day product as an hourly contract is also possible. In that case there is usually a 3-hour lead time before delivery can be executed.

Figure 43. Trading within-day products.



Source: Powernext

The contract volume is calculated on the basis of the factors of the number of delivery days in the delivery period and the quantity to be delivered daily. This quantity usually amounts to 24 MWh, on the day of the switch from winter time to summer time it amounts to 23 MWh, whereas on the day of the switch from summer time to winter time it amounts to 25 MWh.

Indicatively, the following table presents the characteristics of a Spot Market Gas contract of Powernext Exchange:

Table 4. Characteristics of a Gas Contract of Powernext.

Underlying	High calorific natural gas (H-gas quality) at 25°C (PCS)
Delivery	All contracts are physically settled and delivered on the specified virtual PEG of the gas transport network. Delivery occurs each calendar day of the delivery period. For a given day D of the delivery period, the delivery goes from 06:00 a.m. of day D to 06:00 a.m. of day D+1.
Contract volume units	MWh/day for Spot and Futures contracts
Contract volume	1 MWh/day
Minimum lot size	240 contracts (i.e. Minimum Volume = 240 MWh/day)
Volume increment	10 contracts (i.e. Volume Tick = 10 MWh/day)
Price unit	€/MWh, 3 decimal digits
Price tick	0,025 €/MWh
Negative prices	The use of negative prices is not allowed
Total contract volume	= Number of contracts x Contract volume (1 MWh/day) x Number of delivery days*
Maturities	WD : Within-Day DA : Day-Ahead WE : Week-End
Tradable products	<ul style="list-style-type: none"> • A WD Product is tradable each trading day for delivery on the same day, • A DA Product is tradable each trading day for delivery on the following trading day, or, alternatively, on the day communicated in a Market Notice, • A WE Product is tradable two trading days preceeding a week-end for delivery on Saturday and Sunday, or, alternatively, on the days communicated in a Market Notice
Transformation for clearing purposes	Immediately after the conclusion of the trade, each WE contract is split into the corresponding daily contracts so the covered delivery period remains the same
Tradable Spreads	Powernext offers a Spread between the PEG Sud / PEG Nord Products. Trading on this Spread

between products	results by the buying (respectively the selling) of the first PEG Sud Product and the selling (respectively the buying) on the second PEG Nord Product.
Trading hours	From 09:00 to 18:00 CET
Order book opening hours	From 07:00 to 18:00 CET

Source: Powernext

3.2.2.2. DERIVATIVE CONTRACTS FOR NATURAL GAS

Simultaneously with the spot market, European energy exchanges offer futures contracts for physical delivery of natural gas, which are similar to those of electricity.

3.2.3. CLEARING OTC TRADES

3.2.3.1. REGISTERING OTC SPOT TRADES

Many exchanges offer the service of clearing and registration of OTC bilateral trades in electricity in the respective national registries.

3.2.3.2. FORWARD CONTRACTS - FORWARDS (REGISTRATION OTC)

Forward OTC contracts involve OTC bilateral agreements for the purchase or sale of a specific quantity of electricity at a specific time period or at a specific price. Many exchanges offer the service of clearing and registering of these transactions in the respective national registries.

3.2.4. SUPPLEMENTARY PRODUCTS

3.2.4.1. GREEN CERTIFICATES

A green certificate is "proof" that the electricity fed into the grid from a producer comes from a renewable source. This certificate is a document (printed or electronic) containing information for the operator and facilities: company name, address operator, facility location, capacity, date of award, technology sector, funding that may have been received.

The green certificates are tradable certificates that guarantee that the electricity specified therein has been produced from renewable sources. These certificates are issued and delivered free of charge to producers of renewable electricity, with a ratio of one certificate for each unit of electricity that has been proven to have been produced by renewable energy. The market for these certificates, like any other market, functions under demand and supply, which essentially determine the price of the certificates.

The supply of green certificates comes from the producers of renewable electricity. These producers can sell their certificates in certain Member States in which they operate. Currently this operation is available in the Netherlands, Denmark, United Kingdom, Belgium,

Italy, Sweden, and subsequently throughout the EU if the green credentials are mutually recognized by all EU Member States.

Currently in Greece there is no legal framework for the issuance and trading of "Green Certificates". Although the National Policy sets a target for the minimum energy production from renewable sources, there is no regulatory framework that specifies the procedures and requirements for the certification of electricity from renewable sources.

Consequently, since the mechanism of "Green Certificates" is not supported by relevant laws and is not applicable in Greece, green certificates cannot be issued in Greece, or purchased abroad and used in Greece.

3.2.4.2. RENEWABLE ENERGY CERTIFICATES, GUARANTEE OF ORIGIN

A **Renewable Energy Certificate (REC)** or a **guarantee of origin** is a certificate that proves that power is produced from renewable energy sources. A certificate represents the production of a megawatt hour of electricity. A REC is sold separately from the power output. The buyer of a REC can claim after the acquisition that he has purchased renewable energy.

When the competent body for issuing the certificate - issuing authority – is appointed by the government, the system is called system of guarantee of origin or GO-system, and when the issuing agency is appointed by market players it is called RECS-system. In some cases a guarantee of origin shall be accepted by a system of RECs, but the reverse is not possible. The Guarantee of Origin and the REC certificates are standardized within the European Energy Certification System and exclude one another (dual version is not possible).

There are currently 16 countries with a standardized system certificate. The issuing authority as a member of the Association of Issuing Bodies (AIB) allows market players to transfer licenses from one system (or country) to another.

The **European Energy Certification System (EECS)** is a commercially funded, comprehensive European framework for the issuance, holding, transfer and processing of different electronic files. It is developed by the AIB to provide a suitable platform for setting Guarantees of Origin Renewable Energy, as proposed by Directive 2009/28/EC (Directive on renewable energy), which supports the Directive 2009/72 / EC (Directive on the internal market in electricity). The EECS supports all types of electricity, regardless of the source or production technology.

In Greece the corresponding certificates are offered through the following procedure:

- **Guarantee of Origin (GO):** The electronic certificate issued by the Competent Body Issue (Independent Power Transmission Operator (IPTO)), certifying the origin of 1MWh of electricity produced from a RES or CHP facility for a specified period.
- **Purpose of GO:** It is proof to the final user that a proportion or amount of electricity has been produced from RES or CHP even though the electricity supplier has no renewable energy or CHP capacity of its own.

- issuing body:
 - a) The responsible Operators or CRES as defined in Article 16 of L.3468/2006 order for electricity produced from RES and
 - b) For electricity produced from high efficiency cogeneration without using RES, the Transmission System Operator where the establishment is located in the geographical area served by the interconnected system (either connected to the system directly or through the Network, or a stand-alone installation) and the non-Interconnected Islands when installed in a non-interconnected islands (whether connected to the network of the island or stand-alone installation).
- **Supervision Authority:** the Regulatory Authority for Energy (RAE) as defined in Article 16 of Law 3468/2006.

3.2.4.3. ENERGY SAVINGS CERTIFICATES

The **energy saving certificate** is a tradable certificate. Each energy saving certificate is equivalent to one tonne of CO₂-e from energy-saving activities.

In the environmental policy, energy saving certificates (ESC), or **white certificates** are documents certifying that a certain reduction of energy consumption is achieved. In most applications, white certificates are tradable and combined with an obligation to achieve a specific savings target. Under this system, manufacturers, suppliers or distributors of electricity, gas and oil are required to undertake energy efficiency for the end user, which is consistent with a fixed percentage of the annual energy quantities they produce. If the energy producers do not meet this target for energy consumption they are required to pay a penalty. White certificates are given to producers whenever an amount of energy is saved, so the manufacturer can use the certificate of conformity for their own goals or they may be sold to others who cannot achieve their own respective goals. Quite similar to the closely related concept of emissions trading, the liquidity in theory guarantees that the total energy savings are achieved with the minimal cost while the certificates guarantee that the overall savings target is achieved.

A white certificate, also called **Energy Savings Certificate (ESC), Energy Efficiency Credit (EEC)**, or white tag, is an instrument issued by an authorized body guaranteeing that a certain amount of energy savings has been achieved. Each certificate is a unique and identifiable commodity carrying a property right over a certain amount of additional energy savings and ensures that the benefit of these savings has not been recorded elsewhere.

A white certificate can be expressed in units of energy saving, such as 1 megawatt hour (MWh), or in common energy units that allow direct comparisons of efficiency between gas and electricity saving, such as British thermal units or tons of oil equivalent. White certificates can be designed to incorporate estimated savings over the expected life of the measure or represent efficiency savings on an annual accumulated basis. The assignment of one MWh to a white certificate simplifies its use, making it easier to compare with the Renewable Energy Certificate (REC).

White certificates can be used for the purchase and sale of the social and environmental benefits as a separate product, either bilaterally or at auction, with the package of benefits

belonging to each successive owner. The ESC credited the owner of the ESC when it is withdrawn and the particular owner can make the relevant assertions related to energy conservation. Similar to the Renewable Energy Certificate (REC), the ESC may be withdrawn only once, for one purpose only.

3.2.4.3.1. ENERGY SAVINGS CERTIFICATE ON POWERNEXT

An **Energy Savings Certificate** (Certificats d'Economies d'Énergie or CEE in French) is an instrument created in 2005, enabling the promotion and stimulation of investments in terms of energy efficiency (within the context of European objectives) through a market mechanism.

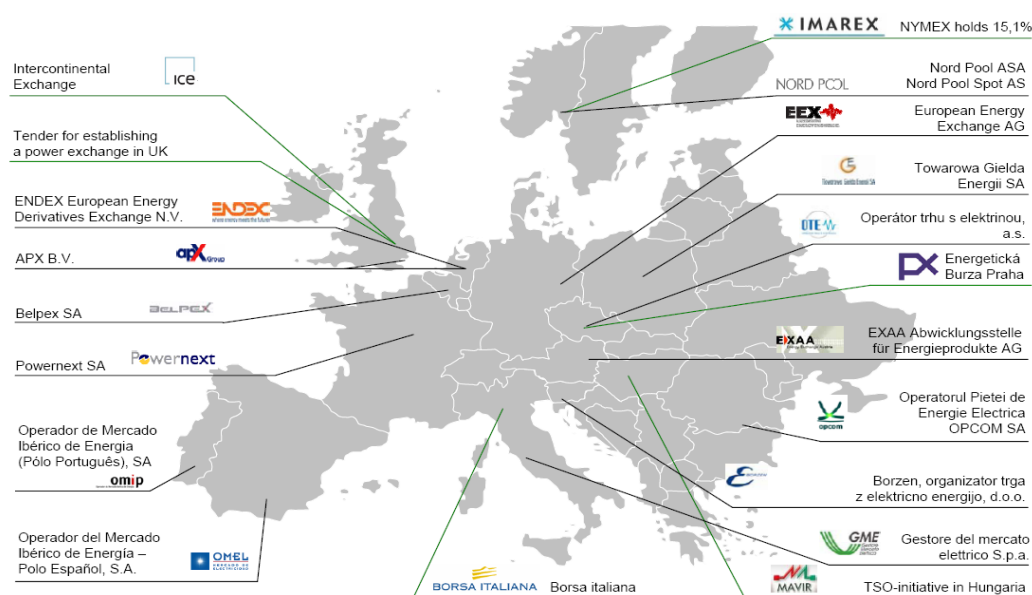
The government determines individual energy savings obligations (in **MWh** for a specific period) to energy providers: **the "Obligés"** must save the amount allocated or they will face financial penalties.

The Obligés encourage their final clients to save energy through various investments in energy efficiency (insulation, condensing boilers, etc.) rewarded by certificates credited by governmental agencies on a registry. Other "non-Obligés" actors (**the Eligibles**) may also participate in the process without any obligations other than selling their certificates on the market.

Energy Savings Certificates are tradable instruments that actors can exchange bilaterally or through the Powernext Energy Savings multilateral platform.

3.3. EUROPEAN ENERGY EXCHANGES

Picture 18. Energy exchanges across Europe.



The most significant Energy Exchanges in Europe are:

3.3.1. NASDAQ OMX COMMODITIES – NORDPOOL SPOT AS

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).

3.3.1.1. NASDAQ OMX COMMODITIES

www.nasdaqomxcommodities.com



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 countries), 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.

3.3.2. 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 percent of total energy production in the Nordic region is traded here. The rest is traded through bilateral contracts between suppliers, retailers and end consumers.

Picture 19. 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.

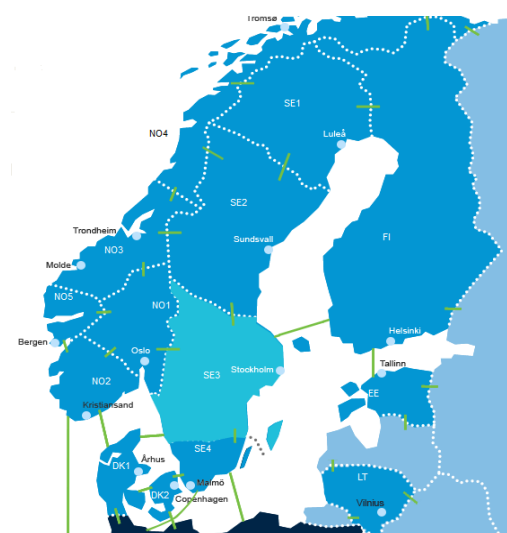
The market which the operation of Nord Pool Spot power exchange covers is divided in some areas (market areas), otherwise bidding areas. This division is decided by the electricity TSOs of each country and is decided in order to better manage congestion in the flow of electricity to the transmission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

As shown in Table 5, 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 6.

Table 5. 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)				

Picture 20. Market areas of Nord Pool Spot.



Source: Nord Pool Spot

Table 6. TSOs involved in the operation of Nord Pool Spot.

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

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.

In 2012, the total trading volume over Scandinavia amounted in 334 TWh, including the auction volume of UK N2EX. This represents a value of € 12 billion, while in 2010 it reached 18 billion euros. 98-99% of trading volume in the market was Elspot. Nevertheless, the

market Elbas plays an essential role in creating the necessary balance between supply and demand. The Elspot market operates through auction, where prices and volumes are agreed at 12:00 CET for next day delivery. However, circumstances may occur between the two time points that change the balance of the system. A power plant may stop working in Norway, or strong winds can cause greater output power than is provided for in wind power in Denmark. In Elbas, buyers and sellers can trade quantities close to real time to bring the market back into balance, while reducing risk and potentially improving profits for members.

Table 7. Main figures of the energy market of Nord Pool Spot

Nord Pool Spot AS	2013	2012	2011	2010	2009
Turnover Elspot (day-ahead)					
Volume (TWh)	348.9	334	294.4	305.2	285.5
Value (EUR mil)	13,459.7	12,131.2	14,335.5	17,970.0	10,739.5
Market share in Scandinavia (%)	84%	77.1%	73.1%	74.4%	72%
Volume of intraday market (TWh)	4.2	3.2	2.7	2.2	2.4

Source: Nord Pool Spot

3.3.3. 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.

EEX holds a 50 percent stake in the joint venture SPOT EPEX based in Paris, which operates the spot market for Germany, France, Austria and Switzerland.

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.

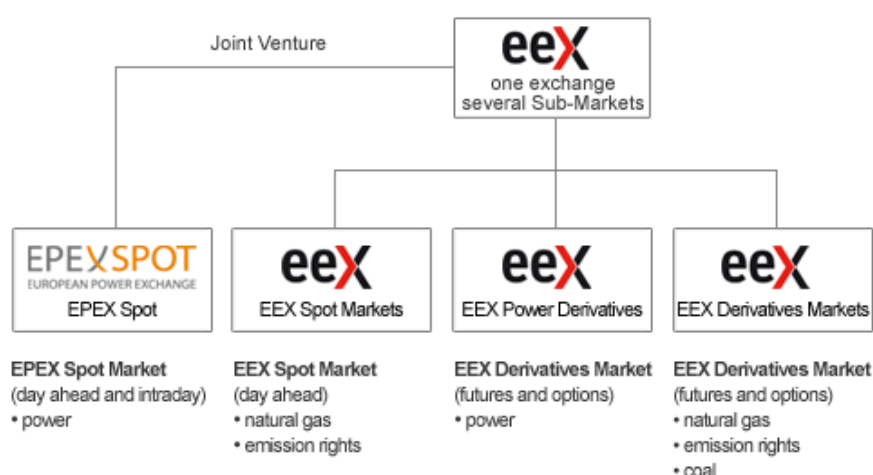
The Derivatives market offers financially settled power futures for Germany/ Austria (Phelix Futures) and France (French Futures) as well as options on Phelix Futures. Maturities offered for trading comprise Day, Weekend, Week, Month, Quarter and Year Futures. In addition to the settlement of transactions 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 44. The sub-markets of EEX.



Source: EEX

The products traded on the European Energy Exchange are:

Table 8. Products traded in EEX.

	Spot market	Derivatives Market	Trade Registration
Electricity	EPEX Spot <ul style="list-style-type: none"> Day-Ahead Auction (D/A, F, CH) Intraday (D, F) 	EEX Power Derivatives <ul style="list-style-type: none"> 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 <ul style="list-style-type: none"> Global gas spot contracts (GASPOOL, NCG, TTF) 	EEX Physical Futures (NCG, GASPOOL)	EEX Relevant products Gas Futures (NBP)

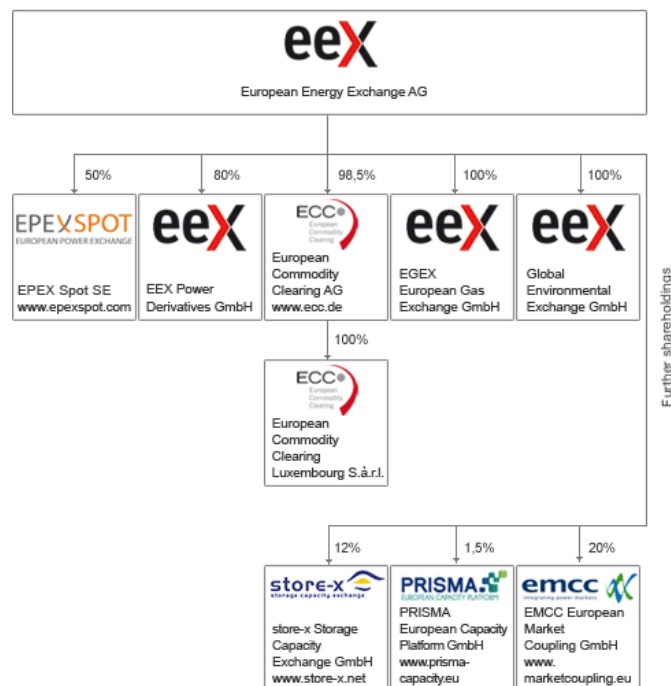
	Spot market	Derivatives Market	Trade Registration
Emission rights CO2	<ul style="list-style-type: none"> Spot contracts quality-specific H- and L-gas (GASPOOL, NCG) Day contracts Weekend contracts 		Gas Futures (IT)
	<p>EEX EUA EUAA CER Primary Auction EUA Primary Auction EUAA</p>	<p>EEX EUA Futures CER Futures EUA Options EUA Primary Auction</p>	<p>EEX All spot products All derivatives products</p>
Coal	/	<p>EEX Financial Futures (ARA, RB)</p>	<p>EEX Coal Futures</p>

Source: EEX

Furthermore, EEX holds 20 percent in EMCC GmbH (European Market Coupling Company), a company that performs congestion management in German-Danish border. Also, the EEX maintains interests in Store-x GmbH (Storage Capacity Exchange), an online platform for the secondary market for gas storage, and PRISMA European Capacity Platform GmbH, an online platform for natural gas transport capacity.

The participations of EEX are presented in the following graph:

Figure 45. Participations of EEX.



Source: EEX

Table 9. Activity results of EEX.

Results		2013	2012	2011	2010	2009
Sales revenue	K€		47.921	46	43.157	34.604
Earnings before interest, taxes, depreciation and amortization (EBITDA)	K€		15.299	20	19.496	25.758
Earnings before interest and taxes (EBIT)	K€		12.371	16	15.605	12.803
Earnings before taxes (EBT)	K€		13074	17,205	15913	13120
Core Business Parameters						
Spot Market						
Power Spot Market volume	TWh	346	339	309	279	203
Emissions Spot Market volume	1000 t		111.244	25.640	25.184	9.709
Natural Gas Spot Market volume	GWh	80.600	35.914	23.091	15.026	3.516
Participants in EPEX Spot		222	211	201	192	185
Participants in EEX Spot		178	162	123	116	103
Derivatives Market						
Power Derivatives Market volume	TWh	1.264	931	1.075	1.208	1.025
Emissions Derivatives Market volume	1000 t		143.391	81.048	127.197	23.642
Natural Gas Derivatives Market volume	GWh	29.500	39.548	35.507	31.863	11.361
Coal Derivatives Market volume	1000 t		0	420	135	117
Participants in EEX Power Derivatives				172	157	146
Participants in EEX Derivatives		198	185	170	166	152

Source: EEX

3.3.4. 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 26th November 2008 in order to hedge volume and price risks for natural gas in France. On 1st July 2011, GRTgaz and Powernext launched the first gas market coupling initiative in Europe between GRTgaz's PEGs Nord and Sud. Powernext launched on 1st February 2013 a natural gas Futures market on the TTF hub in the Netherlands.
- Powernext and EEX launched PEGAS on 29 May 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 10th January 2012.

- Powernext owns a 50% equity stake in EPEX SPOT and a 20% in EEX Power Derivatives.

Powernext started as a regulated investment firm based in Paris and operating under the “multilateral trading facility” (MTF) status and in February of 2014 it became a Regulated Market. 39 full-time employees are working for the Powernext holding company (111 in the group) in the IT, legal, regulatory, administration, finance, product and business development, communication and sales functions. In 2010, the Powernext Holding Company had a consolidated turnover of 23 million Euros, while in 2012 it reached 26 million Euros. The net profits of the company in 2012 reached 5,1 million Euros.

Energy Futures in Powernext began trading in 2004. In 2005 trading in emission rights products started, and in 2007 services to clear OTC Futures began. In July 2006 Powernext participated with 10% in the new Belgian power exchange Belpex owned by Elia (60%), RTE (10%), TenneT (10%), APX (10%) and Powernext (10%).

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 (APX, Powernext, Belpex) and the three transmission system operators (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.

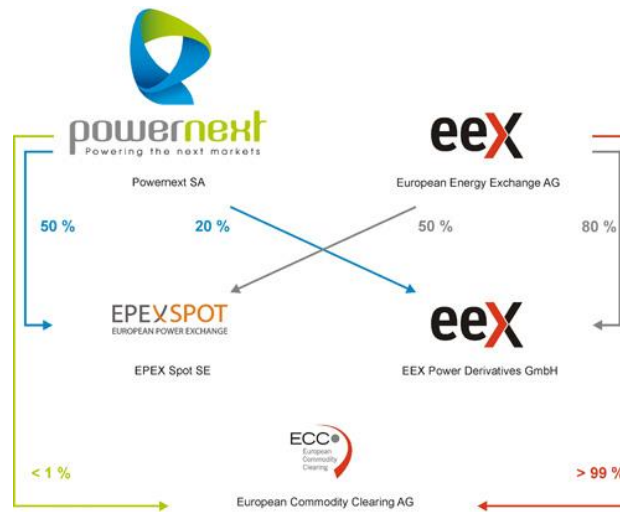
In April 2009, EPEX Spot transfers the clearing activity for French Power Products (Day-Ahead and Intraday) from LCH.Clearnet SA to ECC (European Commodity Clearing AG), Powernext transfers French Power Futures market (Powernext Futures) into EEX Power Derivatives GmbH along with its 44 trading members. 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’s capital of €11.920.730 is held by a group of European transmission system operators in electricity and natural gas, and European energy utilities.

Powernext and EEX both hold stakes in these joint ventures as explained in the graphic below.

Figure 46. Powernext and EEX common participants.



Source: Powernext

Gas Market Products

The organized Powernext Gas market enables participants to trade natural gas at the standard conditions on the French PEGs (Points d’Echange de Gaz – Gas Exchange Points) as of 26 November 2008, as well as the Dutch TTF (Title Transfer Facility) hub since 1st February 2013.

The Powernext Gas Spot market segment offers spot contracts on all three PEGs: Nord, Sud and TIGF:

- the «**Within-Day**» contract enables the intraday arbitrage and balancing for the running gas day (the French gas transport network offers daily and not hourly balancing).
- the «**Day-Ahead**» contract enables to buy/sell gas for the next gas business day.
- the «**Week-End**» contract enables to buy/sell gas for the coming week-end.
- on these three maturities, a PEG Sud/PEG Nord Spread product is also offered.

Picture 21. The Powernext Gas market.

	PEG Nord	PEG Sud/PEG Nord	PEG Sud	PEG TIGF
WD	■	■	■	■
DA	■	■	■	■
WE	■	■	■	■

GAS SPOT

Source: Powernext

The contracts are continuously traded from 08:30 to 18:00 on business days. 7 liquidity providers continuously provide liquidity by offering bid-ask spreads on the trading screen. Spot and Futures contracts coming to expiry are physically settled via a nomination to the GRTgaz and TIGF grids by the clearing house ECC.

Gas Futures

The Powernext Gas Futures market segment offers Futures contracts on the PEG Nord, the PEG Sud and the TTF hub, and enables to trade:

- the **next month** on the PEG Sud,
- the **next three months** on the PEG Nord and the TTF,
- the **next three quarters** on the PEG Nord, the next four quarters on the TTF
- the **next three gas seasons** on the PEG Nord and on the TTF,
- the **next calendar year** on the PEG Nord, the next three calendar years on the TTF.

Picture 22. The Powernext Gas Futures market.

	TTF	PEG Nord/TTF	PEG Nord	PEG Sud/PEG Nord	PEG Sud
G A S F U T U R E S	Months	3	3	3	1
	Quarters	4	3	3	
	Seasons	3	3	3	
	Calendar	3	1	1	

Source: Powernext

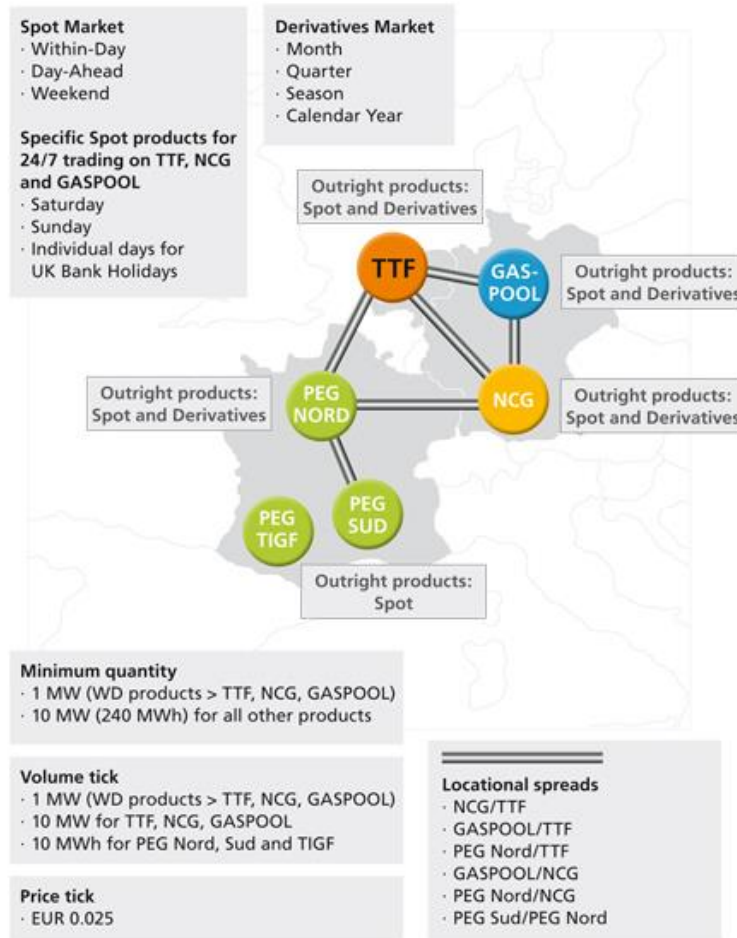
PEGAS – Pan-European Gas Cooperation

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, PEG Nord, PEG Sud and PEG TIGF 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.

Picture 23. PEGAS market areas and products.



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. Further to this, EEX expanded its offering with quality-specific gas products in October 2013. Until the end of 2013, a volume of 1.874.392 MWh has been traded in these new products.

3.3.5. EPEX SPOT SE

www.epexspot.com



EPEX Spot is a joint venture owned by the French Powernext (50%) and the German EEX (50%) located in Paris. 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.

Picture 24. The electricity market of EPEX Spot.

The European Power Exchange EPEX SPOT SE operates the power spot markets for France, Germany, Austria and Switzerland (Day-Ahead and Intraday). Together these countries account for more than one third of the European electricity consumption. EPEX SPOT SE is a European company (Societas Europaea) based in Paris with a branch in Leipzig. 339 TWh were traded on EPEX SPOT's power markets in 2012.



Source: EPEX Spot

The products that can be traded on EPEX SPOT are standard contracts for the physical delivery of electricity within the Austrian, French, German or the Swiss transmission systems. The products are characterized by two different trading processes: auction and continuous trading.

Table 10. Characteristics of the Day ahead market of EPEX Spot.

Epex Spot Day Ahead Market features

Day-Ahead Market by Region	<ul style="list-style-type: none"> • EPEX Spot Market Auction Day-Ahead for Area France (French Day-Ahead Auction) • EPEX Spot Market Auction Day-Ahead for Area Austrian / German (Austrian / German Day-Ahead Auction) • EPEX Spot Market Auction Day-Ahead for Area of Switzerland (Swiss Day-Ahead Auction)
Trading Procedure	Daily Auction
Trading Period	All year
Traded Products (Maturities - delivery)	Electricity for one hour of the day Hour 01: The period between 00:00 and 01:00 Hour 02: The period between 01:00 and 02:00 Hour 24: The period between 11:00 and 00:00
Maximum and Minimum Order	3000.0€ /-3000.0€
Price Characteristics	Prices in Euro / MWh with one decimal point
Volume Characteristics	Volumes in MW

Source: EPEX Spot

In addition to the above, in EPEX Spot power exchange Market Coupling Contracts for electricity are traded (Market Coupling Contracts). EPEX is the only energy exchange on which such contracts are traded.

Generally, in EPEX power exchange Spot two main categories of contracts are traded: Physical Delivery Contracts for Electricity (Physical Power Contracts) and Coupling Contracts for Electricity Markets (Market Coupling Contracts). Physical Delivery Contracts for Electricity refer to transactions in the Day-Ahead Market and Intraday Market and are related to physical quantities of electricity (MWh). Market Coupling Contracts refer to cross-border trades in electricity and for trading Physical Transmission Rights.

Physical Transmission Rights correspond to a specific Available Transmission Capacity (ATC), across borders, the holder of which has the right to transfer electricity within certain capacity limits and can be used for cross-border transactions. These cross-border transactions may relate either to bilateral contracts for the purchase or sale of electricity, either by purchasing orders, or selling electricity in a power exchange in another country.

Table 11. Characteristics of market coupling contracts of EPEX Spot.

EPEX Spot Market Coupling Contract	
Trading Procedure	Daily Auction
Trading Period	All year
Product types	<ul style="list-style-type: none"> • EPEX SPOT France to Germany • EPEX SPOT Germany to France • EPEX SPOT France to Belgium • EPEX SPOT Germany to Netherlands
Traded Products (Maturities - delivery)	<p style="text-align: center;">Electricity for one hour of the day</p> <p>Hour 01: The period between 00:00 and 01:00</p> <p>Hour 02: The period between 01:00 and 02:00</p> <p style="text-align: center;">.....</p> <p>Hour 24: The period between 11:00 and 00:00</p>
Clearing and Settlement	<p>Trade information transmitted by EPEX SPOT SE to the Central Counterparty, ECC AG for Settlement and Delivery of the Contracts.</p> <p>Nomination by ECC to TSOs on the corresponding electrical borders of the contracts:</p>
Delivery procedure	<ul style="list-style-type: none"> • RTE-AMPRION and RTE-EnBW for EPEX SPOT France to Germany • AMPRION -RTE and EnBW-RTE for EPEX SPOT Germany to France • RTE-ELIA for EPEX SPOT France to Belgium • AMPRION -TENNET TSO BV and TENNET TSO GmbH -TENNET TSO BV for Germany to the Netherlands
Quantity Characteristics	<p>Whole MW on the corresponding electrical borders of the contracts:</p> <ul style="list-style-type: none"> • RTE-AMPRION and RTE-EnBW for EPEX SPOT France to Germany ; • AMPRION -RTE and EnBW-RTE for EPEX SPOT Germany to France ; • RTE-ELIA for EPEX SPOT France to Belgium. <p>0,1 MW on the corresponding electrical borders of the contracts:</p> <ul style="list-style-type: none"> • AMPRION -TENNET TSO BV and TENNET TSO GmbH -TENNET TSO BV for Germany to the Netherlands.

Source: EPEX Spot

Day-Ahead markets

Day-Ahead trading volumes in 2013 were totaling **322.788.544 MWh** (2012: 321.228.968 MWh) and can be broken down as follows:

Table 12. Day ahead market volumes of EPEX Spot.

Areas	Volume 2013 in MWh	Volume 2012 in MWh	Average Base Price 2013 / 2012 Euro/MWh
Germany/ Austria	245.566.864	245.268.525	37,78 / 42,60
France	58.478.684	59.282.499	43,24 / 46,94
Switzerland	18.742.997	16.677.944	44,73 / 49,52

Source: EPEX Spot

Intraday markets

In 2013, total trading volumes on the Intraday markets amounted to 23.054.242 MWh (2012: 17.924.234 MWh), including:

Table 13. Intraday market volumes of EPEX Spot.

Areas	Volume 2013 in MWh	Volume 2012 in MWh
Germany/ Austria	19.699.240	15.757.403
France	2.881.145	2.166.831
Switzerland	473.857	0

Source: EPEX Spot

3.3.6. 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.

Table 14. Electricity prices and traded volumes in the Italian Power Exchange.

Year	purchasing price - National Single Price			total volumes (MWh)	liquidity (%)	no. of participants at 31 Dec
	PUN (€/MWh)					
	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

Year	purchasing price - National Single Price			total volumes (MWh)	liquidity (%)	no. of participants at 31 Dec
2012	75,5	12,1	324,2	298.668.836	59,8	192
2013	63	0	151,9	289.153.546	71,6	214

Source: GME

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.

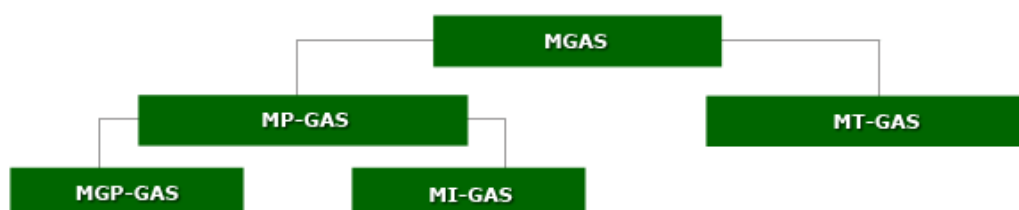
In the MGAS, parties authorized to carry out transactions at the “Punto Virtuale di Scambio” (PSV - Virtual Trading Point) may make forward and spot purchases and sales of volumes of natural gas.

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

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 47. 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 Euro/MWh, specified with three decimals.

Table 15. Natural gas prices and traded volumes in the Italian Power Exchange.

Thermal Year	Continuous Trading				Auction		
	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	3/293
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	-	-	-	0/282			

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.

3.3.7. BORSA ITALIANA – ITALIAN DERIVATIVES ENERGY EXCHANGE (IDEX)

www.borsaitaliana.it



Borsa Italiana, member of the London Stock Exchange Group, operates the Italian Derivatives Energy Exchange (IDEX)¹⁰ as a subcategory of the market of commodity derivatives (IDEX). In this market monthly, quarterly and annual contracts are traded. Power derivatives on IDEX are cash settled against the Single National Price (PUN).

¹⁰ Product characteristics can be found in the link www.borsaitaliana.it/derivati/commodities/factsheet_pdf.htm

Launched in 2008, IDEX is the only regulated financial market on Italian power derivatives and it currently offers both Baseload and Peakload Futures.

Table 16. Product characteristics of Future Contracts of the Italian Derivatives Energy Exchange.

Product Characteristics	
The underlying power spot market	The Day-ahead Market of GME (Gestore Mercati Energetici). The Single National purchase Price (PUN: "Prezzo Unico Nazionale") is calculated for every hour as a weighted average of the zonal prices determined on the day-ahead market.
Contract type:	Base load futures (power delivered every day for 24 hours per day) and peak load futures (power delivered during peak-period from 08:00 hours to 20:00 hours Monday to Friday)
Delivery rate:	1 Megawatt (MW)
Delivery periods:	Monthly, quarterly, yearly
Expiries:	Next 3 months, 4 quarters and 1 year. The second annual expiry is traded from September to the end of December for baseload futures only.
Settlement type:	Cash settlement
Optional physical delivery:	Members of GME markets can ask for physical delivery instead of cash settlement
Trading period:	Until last trading day before the beginning of the delivery period (monthly futures) or until cascading (quarterly and yearly futures)

Source: Borsa Italiana

3.3.8. APX - ENDEX

<http://www.apxendex.com/>

3.3.8.1. APX POWER SPOT EXCHANGE

www.apxgroup.com



The APX power spot exchange operates the spot markets for electricity in the Netherlands, the United Kingdom, and Belgium. APX provides exchange trading, central clearing and settlement, and data distribution services as well as benchmark data and industry indices.

APX has over 150 members from more than 15 countries. In 2012, a total volume of 86 TWh of energy was traded or cleared by APX.

Trading at the Amsterdam Power Exchange (APX) started in May 1999. It was the first electricity exchange market in Continental Europe. At the same year the Europe's first screen-based spot market for trading in wholesale gas, EnMO (now APX Gas UK), was launched in the United Kingdom. In 2000, the UK's first independent power exchange UKPX (now APX Power UK) was established followed by launch of APX-UK electricity spot market in 2001. In 2003, APX expanded towards the UK by acquisition of EnMO and APX-UK (including the brand name APX which was introduced for operations in all countries). UKPX was acquired by APX one year later.

The European Energy Derivatives Exchange N.V. (ENDEX N.V.) was launched in 2002 by a number of energy companies. ENDEX was acquired by APX Group in 2008 and the integration was completed in 2009. After merging the APX Group and ENDEX a new name APX-ENDEX and new logo were introduced.

Picture 25. The markets of APX.



Source: APX

In 2005, APX became a shareholder of Belgian power exchange Belpex SA. In 2010, APX and Belpex announced that they will integrate their activities and Belpex is becoming a part of APX. Belpex is a 100% subsidiary of APX.

In 2006, the trilateral market coupling (TLC) between the Netherlands, Belgium and France was implemented. For coupling of the UK energy market, the APX signed an agreement in 2007 to develop the cable between the UK and the Netherlands, BritNed.

On 25 May 2010, the APX-Endex announced a plan to expand the carbon market and emissions trading to acquire majority stake in carbon trading platform Climex owned by TenneT and Rabobank.

On 9 June 2010, the APX-ENDEX, the Belpex and the Nordic power exchange Nord Pool Spot agreed to create a cross-border intraday electricity market based on technology Elbas Nord Pool Spot, the European Market Coupling Company (European Market Coupling Company). The common intraday market includes the Nordic countries, Germany, the Netherlands and Belgium.

On 1 March 2013, APX-ENDEX was separated into two companies: the power spot exchange APX and the gas spot, gas derivatives and power derivatives exchange ENDEX. As of 27 March, Intercontinental Exchange (ICE) is the majority shareholder of ENDEX. The name of the new company is ICE Endex.

APX Power NL operates the Dutch power market. The core activity of APX Power NL is the Day-Ahead auction. Table 17 presents the characteristics of the APX day-ahead market.

Table 17. Characteristics of the APX ENDEX Day Ahead Market Hourly.

APX ENDEX DAM Hourly	
Delivery Point and Delivery Process	Delivery as purchase contract for the next day in Dutch TSO Tennet TSO BV, through an agreement
Pricing	Euro and Euro cents per MWh
Minimum Price Step	1 Euro cent per MWh, € / MWh 0.01
Minimum Quantity Step	0.1 MW (100 kW)
Price range	Contract prices expressed in € / MWh. minimum / maximum Range -> -3000.00 / +3000.00 € / MWh
Product Expiry	Hourly contracts cease trading at 12:00 CET, the day just before the day of delivery.
Available time periods	Available time periods for the purchase and sale of electricity is each of the 24 hours of day

Source: APX

3.3.8.3. BELPEX

www.belpex.be



Belpex Spot power exchange operates under the Belpex Spot BV and is the Spot market of electricity for the region of Belgium. It is a subsidiary of APX power exchange. It operates under the initiative coupling exchanges in Central and Western Europe (CWE Market Coupling).

The whole territory of Belgium is considered a market area, where contracts to buy and sell electricity are traded. In the operation of the electricity market in Belgium the company Elia System Operator SA (Elia), as TSOs-E is involved. In the Belpex Spot day-ahead market (Belpex DAM) contracts for the purchase and sale of electricity for delivery in the TSO in Belgium (Elia) and in interconnected regions are traded, for delivery the day after this trading, as well as intraday trading products.

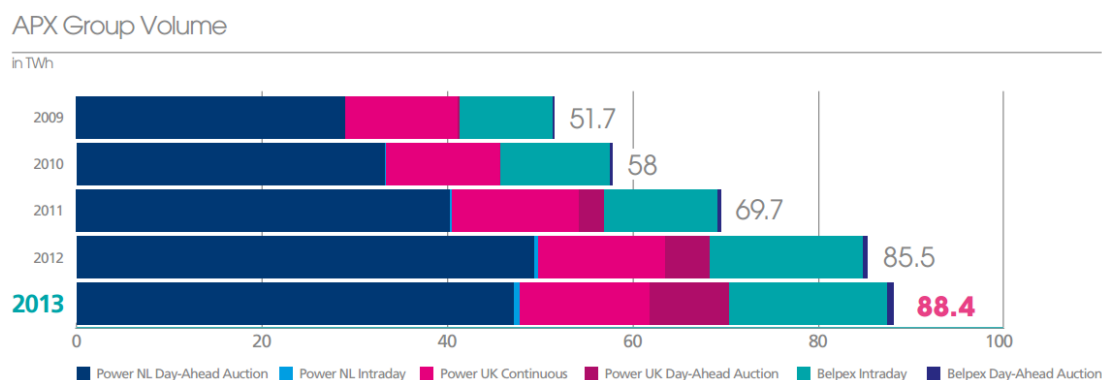
Results of the APXGroup

In 2013 in the Dutch spot market 47,26 TWh were traded, including day-ahead and Intraday markets, compared to 50 TWh in 2012. The total traded volume represents almost half (48%) of the total Dutch load.

In the spot electricity market in Belgium 17,13 TWh were traded in 2013, including day-ahead and Intraday, an increase of 4% compared with 2012. The total volume represents 21% of the Belgian load.

The Power UK volume recorded a total of 22,6 TWh in 2013. The UK Day-Ahead Auction volumes increased 77% year-on-year from 4,84 TWh in 2012 to 8,57 TWh in 2013. Volumes on the Spot Market increased from 10,39 TWh in 2012 to 10,66 TWh in 2013.

Figure 48. APX Group Volume, 2009 – 2013.



Source: APX

The value of the cleared volumes of power and gas of the APX group in 2013 reached €9 billion.

3.3.8.2. ICE ENDEX

www.iceendex.com



ICE Endex serves markets for trading natural gas and power derivatives. In the electricity segment of the market, futures are traded, covering the Netherlands, the United Kingdom and Belgium (weekly, monthly, quarterly and yearly in base, peak and peak 16-hour period).

Gas Market

ICE Endex provides transparent and widely accessible continental European markets for trading natural gas, gas balancing markets and gas storage services, including the Title Transfer Facility (TTF) Virtual Trading Point in the Netherlands, the UK On-the-Day Commodity Market (OCM), the German Virtual Trading Points: GASPOOL and NetConnect Germany (NCG), and the Belgian Zeebrugge Trading Point (ZTP).

The Within-Day Market for **TTF Spot** (TTF) is open for trading on a 24/7 basis. Rolling 24 hourly blocks can be traded continuously and anonymously with the backup of complete TSO (GTS) nomination and clearing services. The Day-Ahead Market is open for trading on Dutch business days from 06:00 am to 04:00 am CET. Individual Days, Weekend Strip, Balance of Week and Working Days Next Week instruments can be anonymously traded on a continuous spot market model, as a primary tool to help shippers to fully optimize their TTF portfolios.

ZTP Spot went live for trading in September 2012 as Continental Europe's first exchange traded market, combining 24/7 virtual gas trading and TSO physical balancing in an end of day balancing model. ZTP Spot is the result of a close cooperation between ICE Endex and Fluxys Belgium SA which offers an anonymous market place for integrated trading, clearing

and notification of day-ahead, within-day contracts for delivery at the ZTP notional hub in Belgium.

The Day Ahead Market of ZTP is open for trading seven days a week, from 06:00 am to 04:00 am CET. Individual Days, Weekend Strip, Balance of Week and Working Days Next Week instruments can be anonymously traded on a continuous spot market model. ZTP Spot is a primary tool to help shippers fully optimize their gas portfolios, vis-à-vis other short term NW European gas markets, on a single screen via Trayport Technology.

The Within-Day instruments for the ZTP Spot market are open for trading on a 24/7 basis. Rolling 24 hourly end of gas day virtual instruments can be traded continuously and anonymously, with the peace of mind of single sided TSO nominations up to 40 minutes before delivery. Further the market is integrated with Fluxys balancing operations, critical TSO balancing messages can be seen via the ICE Endex front end as well as the opportunity to place physical orders resulting in a firm commitment to flow gas to help the system operator restore transmission balance.

The **On-the-day Commodity Market (OCM)** provides trading products to meet the changing requirements of today's traders. Three products are traded on the OCM, namely Locational, Physical and Title, all of which result in exchange of rights to gas at the UK hub, the NBP (National Balancing Point). Two of these products include an obligation to change physical gas flows at entry/exit points around the hub.

ICE Endex is the assigned market operator for the On-the-day Commodity Market. Products consist of Title, Physical and Locational. Of the three products, Title is the most liquid and runs from 12:00 midday Day-Ahead until 03:35am calendar day following the gas day, with gas being delivered in accordance with the UK standard 'gas-day' 06:00hrs until 06:00hrs.

In 2012, the volume of transactions in spot market OCM reached 137 TWh, remaining unchanged compared with the previous year, while trading volume for gas storage reached 928 GWh, increasing by 164%.

In the Derivatives Market of ICE Endex the following products are being traded:

- TTF Gas Futures
- TTF Gas Options
- GASPOOL Gas Futures
- NCG Gas Futures
- Belgian Power Futures
- Dutch Power Futures

In 2012 in the Dutch spot gas market 13,7 TWh were traded, an increase of 15% compared with the previous year, while in the derivatives market the traded volume reached 366 TWh, (includes exchange traded and OTC), an increase of 10%. Similarly, in Belgium 1,8 TWh were traded in the spot market.

Rough Gas Storage Trading

In co-operation with Centrica Storage Ltd (CSL), the Gas Storage is a market for trading secondary storage capacity and gas in store at Rough, the UK's largest gas storage facility. The Gas Storage Market is available to all members of the On-the-day Commodity Market (OCM), provided that they are signatories of CSL's Storage Services Contract and the associated Credit Agreement.

ICE Endex Gas UK members are able to use existing collateral provided for trading on the OCM, while all contracts traded on the Gas Storage Market are fully collateralized to ensure risk is fully covered at all times. APX Commodities Ltd. is appointed by ICE Endex as the central counterparty to all trades; all contracts are traded anonymously, then cleared and settled by APX Commodities Ltd.

All trades at Rough will be notified to Centrica Storage Ltd, a supplier of physical gas storage in the United Kingdom. The transfer of commodity or capacity is made on behalf of members via StorIT, Centrica's online customer services system.

GasTerra – Gas Storage Services

On behalf of GasTerra, ICE Endex auctions gas storage services in the Netherlands. The storage services are sold in the form Standard Bundled Units or SBUs which allow market parties to inject natural gas in or withdraw from a virtual storage facility. Almost 2 bcm of gas storage, in the form of 13,2 million SBUs is offered under market based conditions.

Since 2011, ICE Endex has successfully operated auctions for a yearly product. In addition to the one-year product, ICE Endex introduced a new five-year product, providing long-term storage capacity starting 1 April 2014 and ending 31 March 2019. Roughly 30% was sold as five-year storage capacity in the auction on 20 November 2013. The remaining capacity will be offered as one-year storage capacity for the coming five storage years. The first 3.653.682 SBUs for the storage year 2014-2015 were sold on 21 November 2013. The remaining 5.445.219 SBUs has been offered in the auction on 12 February 2014.

ICE Endex developed a custom built single-sided auction mechanism which ensures that the SBUs are sold in a transparent, independent and market-based way. More importantly, ICE Endex ensures the anonymity of market parties who bid in the auction and the confidentiality of all information regarding their bids. A notary monitors the auction process to ensure that it is conducted in a transparent and non-discriminatory manner. All information pertaining to bidders and their bids is only accessible to ICE Endex and the notary. GasTerra does not have access to this information and neither does it have any involvement in the auction process. The auction process, the rules for price determination and allocation are further detailed in the Auction Rules. ICE Endex facilitates the day-to-day nomination processes as well as the financial settlement of the contracts.

3.3.9. ICE FUTURES EUROPE

www.theice.com



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).

3.3.10. OMI (IBERIAN MARKET OPERATOR).

The two Iberian countries Spain and Portugal decided in 2004 to proceed in the integration of energy markets and create a single entity called the OMI (Iberian Market Operator).

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 (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. Finally, the two exchanges are supervised by the Capital Market Commissions and Regulatory Authorities for Energy (RAE) of each country.

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.

The size of all of these contracts is 1 MW, with a 0,01 Euros/MWh tick.

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.

3.3.11. 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 is planning to operate an electronic auction platform for gas, which will trade weekly, monthly, quarterly and annual contracts for the supply of natural gas.

Trading volume in the day ahead, intraday and bilateral agreements markets in 2012 amounted to 18.983.898 MWh, which corresponds to about 35% of consumption in the country, against 13.990.405 MWh, in 2011, which was 26% of the consumption.

Also, in 2012 1.053.229 green certificates were traded, against 451.841 in 2011. In 2012 there were no transactions for ERU and CER Emission Rights, while in 2011 1.500.000 contracts were traded.

3.3.12. EXAA - AUSTRIA

www.exaa.at



EXAA (Abwicklungsstelle für Energieprodukte AG) is Austria's energy and environmental exchange seated in

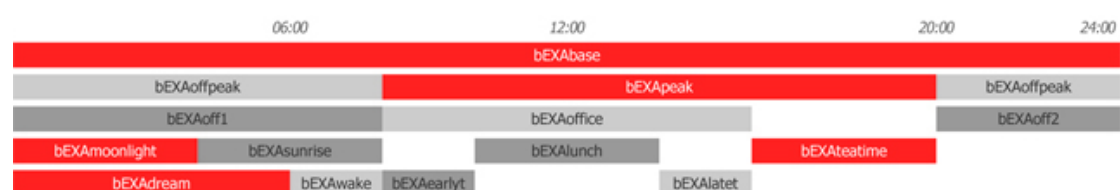
Vienna. EXAA was founded on 8 June 2001 and opened for spot market trading in electric power on 21 March 2002.

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. The EXAA market share is 15,6% of the Austrian electricity market in 2012.

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 EUR 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 49. 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.

Table 18. Traded volume and traded value in EXAA.

		2012	2011
Trade volume (GWh)	7,820	9,346	7,558
Trade value (EUR)	297,856,687	407,174,833	390,236,567

Source: EXAA

3.3.13. 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 opens international gas traders a gateway for trading

in the 2013 implemented entry/exit zone of the Austrian market. In 2012, CEGH achieved a total trading volume of approximately 46,8 bcm of natural gas, thus consolidating its position 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:

- CEGH OTC (over-the-counter) Market,
- CEGH Gas Exchange Spot Market of Wiener Boerse (Day-Ahead and Within-Day Market),
- CEGH Gas Exchange Futures Market of Wiener Boerse.

The CEGH Gas Exchange of Wiener Boerse is operated in cooperation with Wiener Boerse AG and European Commodity Clearing AG (ECC). A fully integrated trading system in combination with comprehensive trading, clearing and settlement services in the heart of CEE offers unique possibilities for international traders.

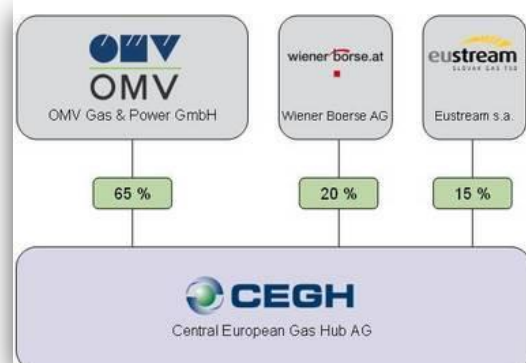
The CEGH Gas Exchange of Wiener Boerse is based on a solid partnership of CEGH, Wiener Boerse and European Commodity Clearing (ECC), each fulfilling different tasks reflecting their strengths.

- *CEGH*, as the Gas Exchange Market operator, operates the physical settlement and is the face to the customer.
- *Wiener Boerse*, as exchange license holder and operator of the Austrian securities exchange, is responsible for the operation of the IT infrastructure for all exchange related systems.
- *European Commodity Clearing (ECC)*, as the commodity exchange clearing house, offers clearing and settlement services for exchange transactions as well as OTC trade registrations.

Following the start of the joint CEGH Gas Exchange of Wiener Boerse at the end of 2009, the Wiener Boerse AG has acquired a 20% stake in the Central European Gas Hub AG as announced on June 17th 2010. This

continues the successful cooperation between OMV and the Wiener Boerse AG. In

Figure 50. CEGH structure.



Source: CEGH

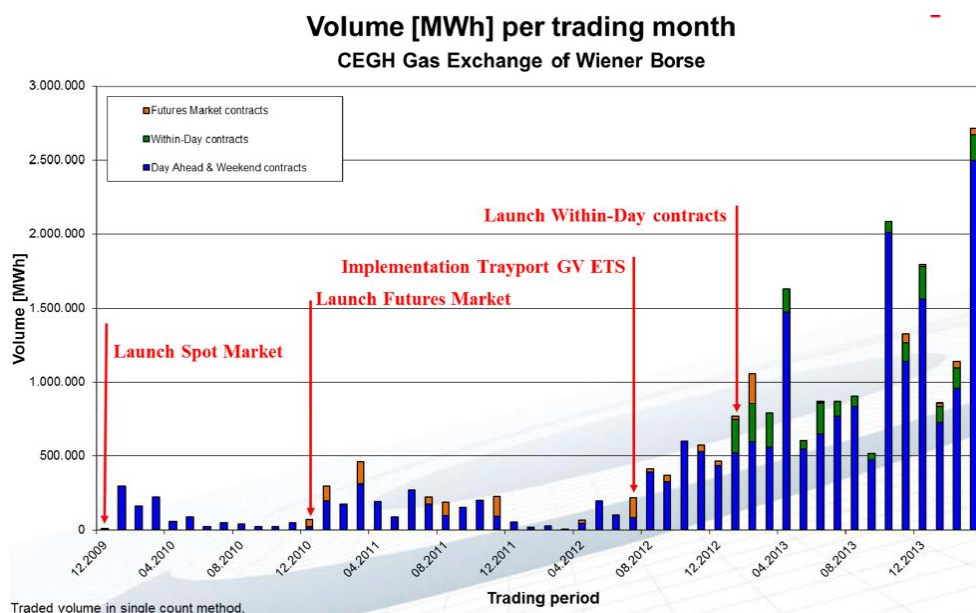
September 2012, Slovak Eustream acquired a 15% stake, which gives another boost to the significance for Central and South-Eastern Europe.

Table 19. Characteristics of CEGH Gas Exchange Products.

	Spot Market		Futures Market
	Within-Day	Day-Ahead	
Gas product type	Base load	Base load	Base load
Delivery point	VTP Austria	VTP Austria	VTP Austria
Settlement	Rest of day with a lead time of 3 hours based on the next full hour to 06:00 am (d or d+1)	Physical delivery from 06:00 am (d+1) to 06:00 am (d+2)	Physical delivery from 06:00 am (d+1) to 06:00 am (d+2)
Trading hours	24/7	From 09:00 am to 05:00 pm	From 09:00 am to 05:00 pm
Price units	EUR/MWh	EUR/MWh	EUR/MWh
Minimum price change	0.025 EUR/MWh	0.025 EUR/MWh	0.025 EUR/MWh
Minimum trade size	1 MW	10 MW	10 MW

Source: CEGH

Figure 51. CEGH Gas Exchange volume, 2009 – 2013.



Source: CEGH

3.3.14. POLISH POWER EXCHANGE

www.polpx.pl/en



Towarowa Giełda Energii SA (currently POLPX) 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, POLPX was the first and so-far only entity to obtain a license to run a commodity exchange market from the Financial Supervision Commission (KNF). Since February 2012, it has been part of the Warsaw Stock Exchange Group, which holds 98% of POLPX shares.

The key areas of POLPX 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)
- CO₂ Emission Allowance Market (EAM).

The Commodity Forward Instruments Market with Physical Delivery (CFIM) was established on November 19th, 2008. Initially, the CFIM market traded BASE-type contracts with 24h execution. On January 19th 2009, POLPX introduced PEAK5 contracts with supply between 7:00 and 22:00 (15 hours per day), on working days.

Currently, the CFIM Market is trading four types of instruments (classified in relation to their term of execution):

- Weekly (BASE_W), (PEAK5_W), (PEAK7_W), (OFFPEAK_W)
- Monthly (BASE_M), (PEAK5_M), (PEAK7_M), (OFFPEAK_M)
- Quarterly (BASE_Q), (PEAK5_Q), (PEAK7_Q), (OFFPEAK_Q)
- Yearly (BASE_Y), (PEAK5_Y), (PEAK7_Y), (OFFPEAK_Y)

Three nearest series of contracts are being traded for a particular execution date. This means that for instance if a monthly BASE_M-01-09 contract is being executed (01 means the number of the month - in this case it is January, 09 means the year, in this case 2009), there will be three subsequent monthly contracts in the trading period: BASE_M-02-09, BASE_M-03-09 and BASE_M-04-09. PEAK5 contracts are traded in a similar way.

Trading of the contracts is carried out in the continuous trading mode only, in the form of a table of orders, using the IT system of POLPX. Trading sessions take place from Monday to Friday 8:00 to 14:00.

The total volume of trading in electricity markets of POLPX in 2012 reached 131.997 TWh, showing an increase of 4,20% over the previous year. This amounts to 82,57% of the total energy produced in Poland and 84,06% of total consumption.

In 2006, POLPX launched a spot market for CO₂ emission certificates in collaboration with the National Administrator of the Emission Allowance Certificates Trading System. Participants of this market can trade EUA units (European Union Allowance).

Natural Gas market

In December 2012 POLPX admitted forward contracts to trading on the Commodity Forward Instruments Market with physical delivery. The contracts are settled by way of a physical delivery of Group E high-methane natural gas and are hereinafter referred to as “gas forward contracts”. The launch of the Commodity Forward Instruments Market with physical delivery (gas) is only the beginning for the gas exchange in Poland. On 31 December 2012 the gas spot market Day-Ahead Market (DAMg) was launched.

The first half of 2013, the total trading volume in the gas reached 464.648 MWh, 179.071 MWh of which were traded in the spot market and 285.577 MWh in the forward market.

The total trading volume of the day-ahead market of natural gas in 2013 reached 1.399,76 MWh.

Energy Efficiency Certificates

As of 4 November 2013, the property rights arising from Energy Efficiency Certificates, i.e. the so-called White Certificates have been introduced to trading on the Polish Power Exchange.

The trading takes place daily, Monday till Thursday; OTC deals on Mondays and Wednesdays, session trading on Tuesdays and Thursdays.

The Certificate of Origin Register keeps the records of the quantity of the Energy Efficiency Certificates and the property rights arising therefrom with the accuracy of 0,001 toe. This means that the number of the Property Rights corresponds to the toe value specified in the relevant Energy Efficiency Certificate where one property right corresponds to 0,001 toe. Toe stands for a tonne of oil equivalent, i.e. the equivalent of one tonne of oil with calorific value of 41.868 kJ/kg.

3.3.15. OTE (CZECH REPUBLIC)

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



OTE, a.s., was founded on 18 April 2001 as a joint-stock company 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. In connection with OTE’s new role in the gas sector, the Company’s original business name – Operátor trhu s elektřinou, a.s. – was changed to OTE, a.s., in 2009. OTE, the Czech electricity and gas market operator provides comprehensive services to individual electricity and gas market players. OTE commenced organizing trading in the day-ahead electricity market in 2002 and the intra-day and block electricity markets in

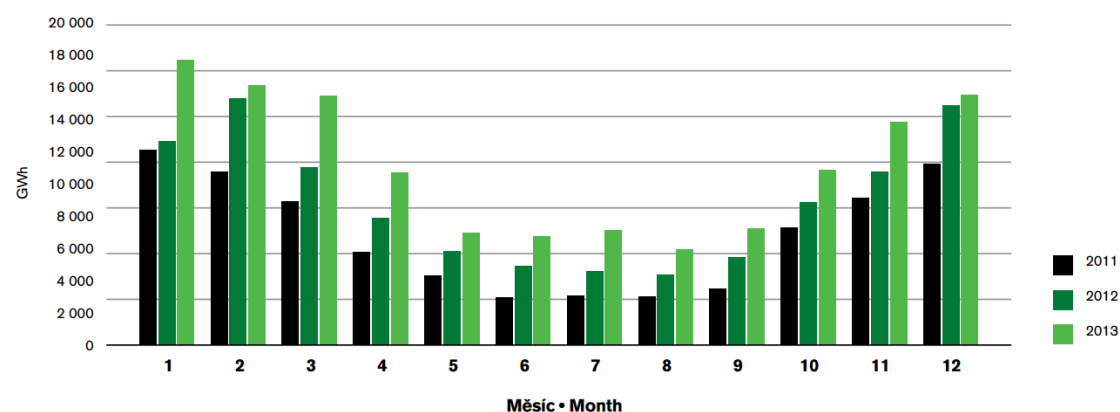
later years. OTE has been the market operator on the gas market since 2010 including operation of day-ahead gas market and intraday gas market.

Continuous data processing and exchange required for the accounting and settlement of imbalance between the contractual and actual volumes of electricity and gas supplied and received are among services offered by the OTE to players in the Czech electricity and gas markets, as well as administrative procedures associated with a switch of supplier. The OTE also administers the National Register of Greenhouse Gas Emissions. OTE is the holder of the license for market operator's activities, which includes activities in the electricity and gas market in the Czech Republic.

In 2013, nearly 92% of traded electricity was registered in the OTE system under bilateral contracts. Compared to 2012, the volume of registered electricity traded through bilateral intra-state contracts in 2013 fell from 112.466 to 101.999 GWh.

As far as the natural gas market is concerned, the entire territory of the Czech Republic is one balancing zone, the so-called Virtual Trading Point (VTP), at which all gas transactions are registered. The Bilateral contracts of the natural gas market in 2013 registered a volume of 135.067.421 MWh, the Day ahead market reported no trades, while the Intraday market reported a total volume of 269.312,5 MWh.

Figure 52. Volumes of bilateral contracts registered in OTE system in 2011 – 2013 (GWh).



Source: OTE

3.3.16. POWER EXCHANGE CENTRAL EUROPE (PXE)

www.pxe.cz



The POWER EXCHANGE CENTRAL EUROPE (PXE) established in July 2007 offers power trading for Czech, Slovak and Hungarian power. PXE is a subsidiary of the Prague Stock Exchange and it is part of the CEE Stock Exchange Group (CEESEG).

Trading involves futures contracts for electricity, which started in 2007 for the Czech Republic, in 2008 for Slovakia and in 2009 for Hungary. In co-operation with the Austrian

energy exchange CEGH, PXE launched derivatives products on natural gas with physical delivery concerning the Czech market. Available product maturities refer to the 3 following months, the 4 following quarters, the 3 following seasons and the next 2 years.

The subject of trading at the PXE is electricity with an hourly output of 1 MW for each hour of each day of the agreed delivery period. The delivery locations are the electricity systems in the Czech Republic (CZ), Slovakia (SK) and Hungary (HU); the transport of electricity is not included in the contract price.

The market trades futures contracts with physical settlement, which involve the commitment of delivery and payment of certain MWh during the entire delivery period. The contracts are annual, quarterly, monthly.

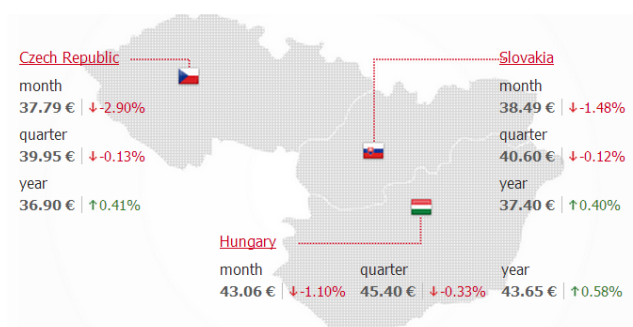
Spot contracts relating to the delivery commitment and payment of certain MWh during a specific delivery date are also traded in PXE.

These contracts are daily or hourly and refer only to the Czech market. Delivery of energy is due Monday through Friday, from 8am to 8pm (including weekends and public holidays) during the delivery period. Hourly products with the place of delivery in CZ are not listed directly as exchange products but as a subject of trading on the OTE Day-Ahead Market, where offers for sale and purchase can be entered using the PXE system.

Until 31 August 2013 the settlement and clearing of trade at PXE was done by the Central Securities Depository and three independent central counterparties. Since 1st September 2013 this system has been replaced by a system run by a major European clearing house, European Commodity Clearing AG (ECC).

The trading volume of future contracts in Czech Republic in 2013 amounted to 24.744.375 MWh (17.864.066 MWh in 2012), in the Slovak market 875.080 MWh (1.562.175 MWh in 2012) and in the Hungarian market to 3.496.914 MWh (400.464 MWh in 2012).

Picture 26. The electricity market of PXE.



Source: PXE

3.3.17. CEGH CZECH GAS EXCHANGE

The CEGH Czech Gas Exchange is a natural gas futures market launched by the Central European Gas Hub (CEGH) and Power Exchange Central Europe (PXE). CEGH with its long experience in operating gas markets and PXE with the know-how of the Czech market and in electricity trading together bring a lot of benefits for gas traders. CEGH Czech Gas Market is operated by PXE. For members of both, CEGH or PXE the access to the CEGH Czech Gas Market is available at reasonable costs with significant discounts on the participation fees.

At the CEGH Czech Gas Exchange the following products can be traded:

Monthly futures	3 consecutive months
Quarterly futures	4 consecutive quarters
Seasons	3 consecutive seasons (winter/summer)
Yearly futures	2 consecutive years

The trading method is order driven with market makers and fully electronic. The market runs on the Trayport GlobalVision Exchange Trading System (ETS). The registration of OTC deals for clearing is possible.

Clearing and settlement is provided by European Commodity Clearing AG (ECC).

3.3.18. HUNGARIAN POWER EXCHANGE (HUPX)

www.hupx.hu



The mission of HUPX Ltd. is to carry out the obligatory task assigned to MAVIR Ltd. (as Transmission System Operator) by the Hungarian Energy Office requiring the formation and operation of the organized

electricity market in Hungary.

In HUPX electricity products are traded in the Day ahead market since 2010, and futures with physical delivery since 2011.

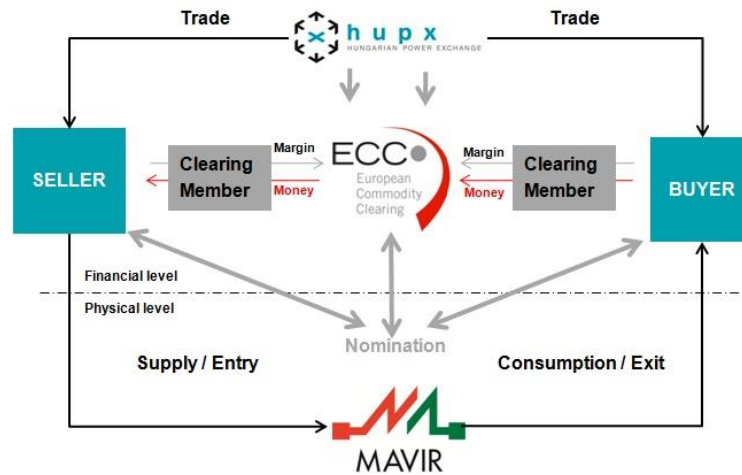
The products that can be traded on HUPXDAM are standard hourly contracts for the day-ahead physical delivery of electricity within the Hungarian transmission systems.

On the HUPXPhF physical futures market four (4) front week, three (3) front month, four (4) front quarter and three (3) front year electricity contracts are tradable, which are physically delivered through the Hungarian electricity grid after their expiry.

The total trade volume in 2012 reached 13 TWh, which represents 30% of total consumption in Hungary. In the day-ahead market 6.321 TWh were traded, while in the futures market 6.291 TWh.

HUPXSPOT day-ahead market auction system is using the EPEX Trading System (operated by EPEX Spot SE is used as single system for French, German/Austrian and Swiss auctions), while clearing is made by the European Commodity Clearing AG (ECC) of EEX.

Figure 53. Trading and clearing procedure in HUPX.



Source: HUPX

3.3.19. BSP SOUTHPPOOL

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.

In the middle of November 2008, BSP took over the implementation of electricity exchange services from Borzen. The company provides Day-ahead and Intra-day trading on the Slovenian electricity market.

Through its affiliates the company is present also on the Serbian and FYROM's electricity markets where the company has established basic infrastructure for trading on electricity markets.

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.

The traders can submit orders with a quantity from 1 – 999 MW, rounded to 1 MWh and a price between €-9.999,99 and €9.999,99.

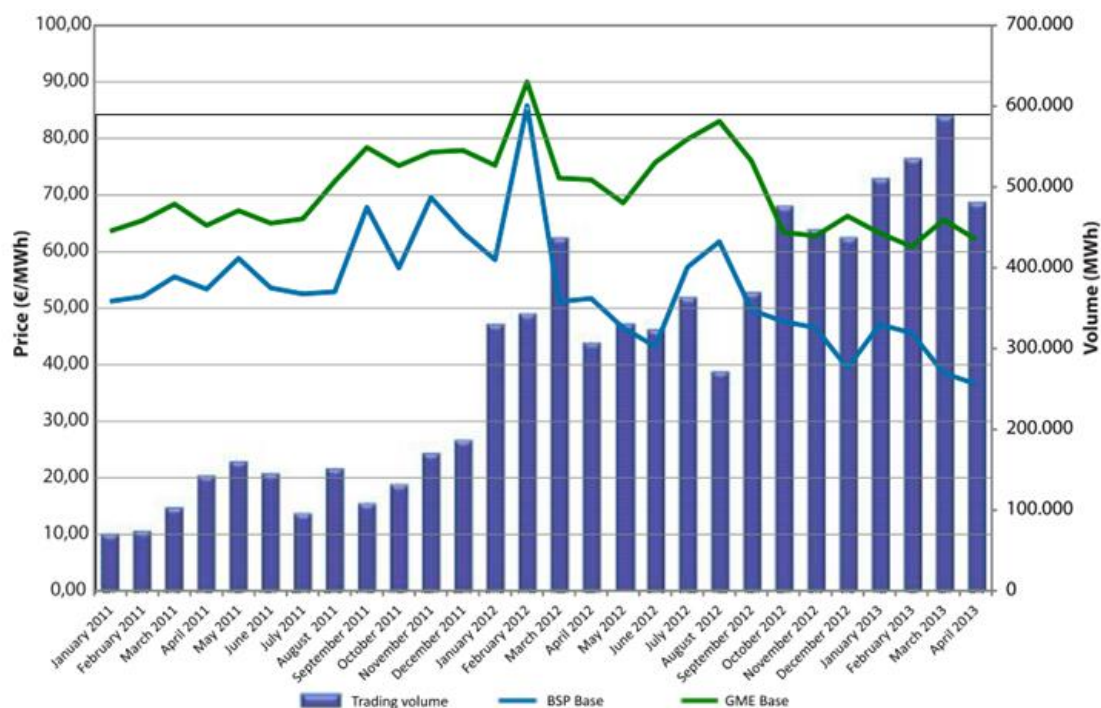
The Trading phase takes place 1 day before the delivery day from 11:00 till 60 minutes prior to product expiration on the delivery day.

Balancing Market

The Balancing market is embedded in the intraday market in which the Transmission System Operator (ELES) buys and sells electricity for the settlement of imbalances in the electricity system. For trading on the Balancing market the same rules as for the Intraday market are applied. The only difference between these markets is a prolonged trading phase on the Balancing market (with regard to the Intraday market) for one hour, until product expiration. Trading results for the Balancing market are part of Intraday market results.

Members of BSP Regional Energy Exchange LL C are also members of BSP’s clearing system. BSP provides the clearing and settlement of transactions concluded on the energy exchange for members.

Figure 54. Trading results of BSP South Pool.



Source: South Pool

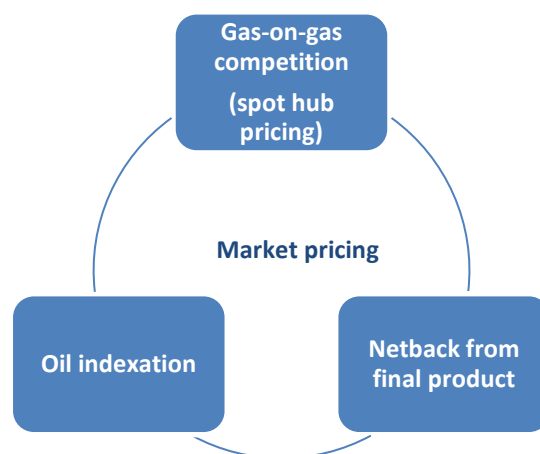
4. THE ROLE OF HUBS IN EUROPEAN NATURAL GAS PRICING

4.1. NATURAL GAS WHOLESALE PRICE FORMATION

A wholesale price level for natural gas can mainly be established via market-based pricing or price regulation. According to the International Gas Union (IGU), there are three major market-based pricing mechanisms:

- Oil price escalation i.e. oil indexation, indicating that the price is linked to competing fuels such as crude oil, gas oil or fuel oil, usually through a base price and an escalation clause,
- Gas-on-gas competition i.e. spot hub pricing, which refers to an indexation to spot prices determined by supply and demand of natural gas traded in physical as well as notional hubs and
- Netback from final product, whereby the price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces (most commonly ammonia) [22] [23].

Figure 55. Market-based pricing mechanisms.



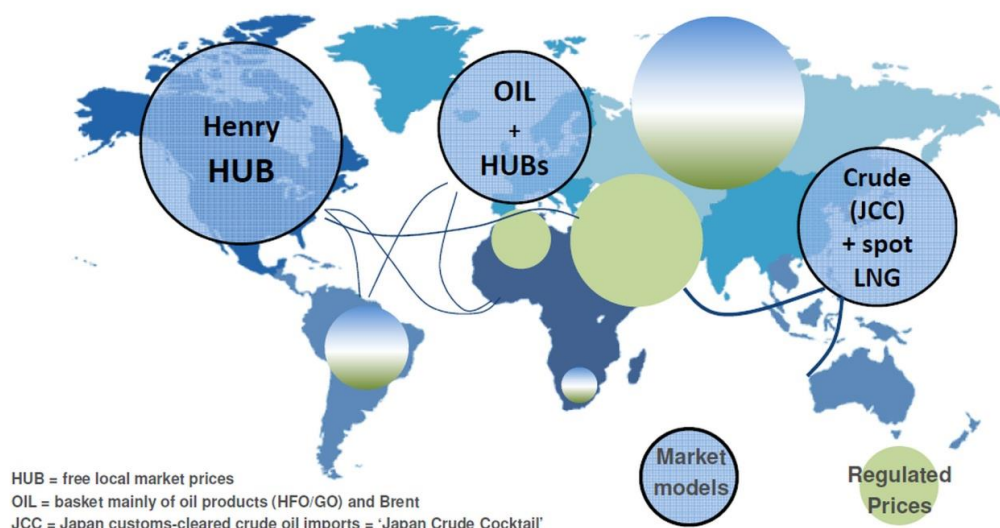
Market-based pricing in fact indicates that the price of natural gas is subject to a number of market factors, such as supply and demand, exploration, production and storage levels, weather patterns, pricing and availability of substitute fuels and market incumbents' views on future developments. It can also mean that the price of natural gas is linked i.e. indexed to another commodity, such as oil, therefore allowing another market to affect the price development of natural gas. Oil indexation is essentially based on the economic concept of substitution.

On the other hand, when the natural gas wholesale price is determined by the government (price regulation), price formation follows government policy objectives. According to the IGU, price regulation mechanisms are principally applied in the former Soviet Union, the Middle East, China, Malaysia and Indonesia. Price formation in Russia is both regulated and non-regulated. Mainly State-owned Gazprom is the major natural gas supplier in the regulated sector, while independent gas producers represent the non-regulated sector.

On the other side of the Atlantic North American natural gas prices are set in an open and highly competitive market. Gas-on-gas competition is after all a mechanism created in the US. Natural gas prices are set based on spot and futures markets where thousands of well-informed buyers and sellers participate.

In Europe, gas pricing systems based on spot markets and oil price indexed formulas have co-existed for more than ten years. Oil indexing emerged in Europe in the 1960s, and spread to Asia, where it remains the prevalent model. However, in today's two-tier European pricing system, oil indexation is losing ground as the European gas market is moving increasingly towards hub-based pricing.

Picture 27. Pricing models.



Source: Bergen Energi

In Europe, the competition oriented EU strategy and the participants' preference to hub-based pricing have led to dramatic changes in the price formation regime. According to IGU,

Europe has been shifting from oil indexation to gas-on-gas competition since 2005. Gas-on-gas competition increased from 15% in 2005 to 45% in 2012 while oil indexation decreased from 78% to 50% during the same period. The remaining 5% is mainly regulated. However, in the Mediterranean¹¹, oil indexation has decreased from 100% in 2005 to just nearly 90% in 2012 with gas-on-gas competition representing the remaining 10%. This shift can be attributed to spot LNG imports with some spot pipeline imports into Italy.

In South Eastern Europe¹² there is no gas-on-gas competition (see Fig. 58). A large segment of price formation is regulated: There is RCS (Regulation: Cost of Service) in Romania and RSP (Regulation: Social and Political) in Croatia. According to IGU, lower imports in Romania resulted in lower oil indexation levels in 2009 and 2010, while the increase in 2012 can be attributed to the Bulgarian shift from Bilateral Monopoly to oil indexation.

GAS-ON-GAS COMPETITION VS. OIL INDEXATION

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. Oil-linked prices were also considered to be more predictable than prices set by gas-on-gas competition. However, they are now under pressure by a combination of factors, predominantly the consequences of the 2008 financial crisis, the full liberalization of British energy markets, the deregulation of European electricity prices and the arrival of shale gas. It is interesting to note that in gas-indexed markets such as in the US and UK, the oil indexed price has a high correlation with the gas indexed price in the long run [24].

There has been a lot of debate about pricing gas based on oil product prices. Nowadays, the transition away from oil product price linkage in contracts has already started, with a significant degree of spot gas pricing indexation in long-term contracts. Major European wholesalers want change. However, oil indexation is preferred by sellers, especially Russia.

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 [25]. It is widely regarded that gas-on-gas competition provides the “right” price of gas. Another advantage of market pricing is that it allows for separate financial risk management since it separates the “financial” from the “physical”. Market pricing is also more transparent and open. The big question is whether traded gas markets will become the dominant gas price-driver in Europe.

¹¹ Greece, Italy, Portugal, Spain, Turkey

¹² Bosnia, Bulgaria, Croatia, FYROM, Romania, Serbia, Slovenia

Figure 56. Price formation in Europe¹³.

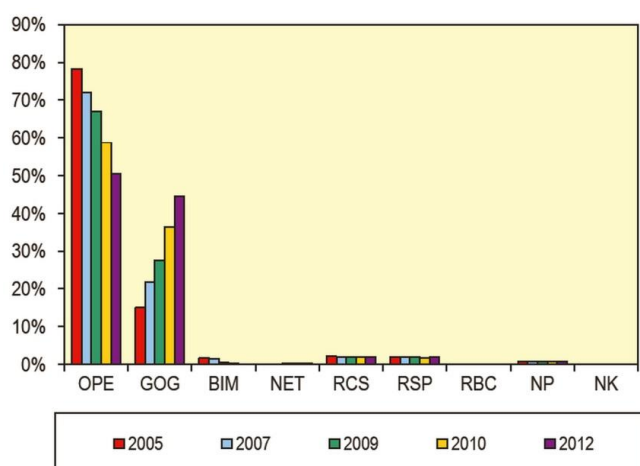


Figure 57. Price formation in the Mediterranean region.

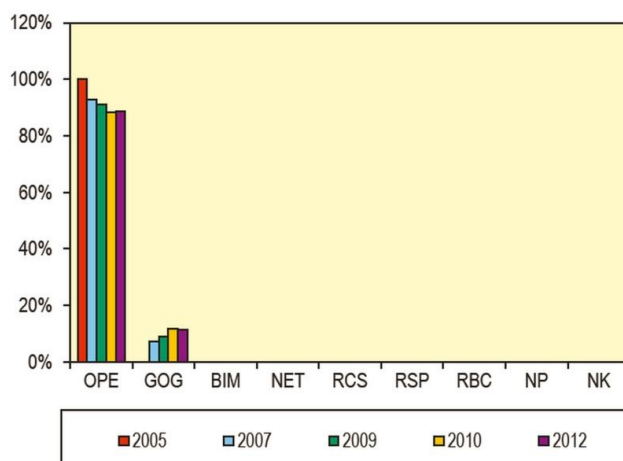
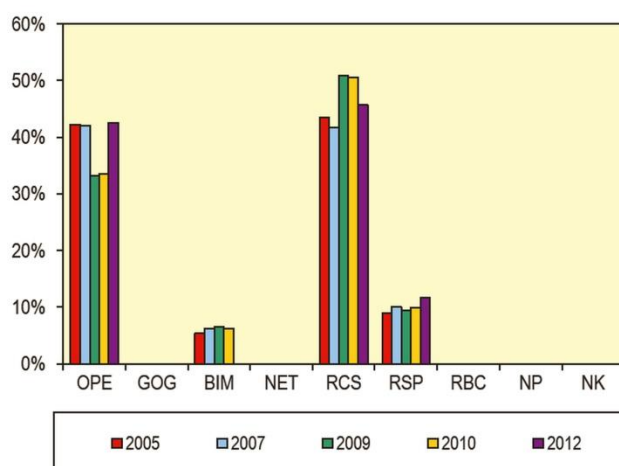


Figure 58. Price formation in South Eastern Europe.



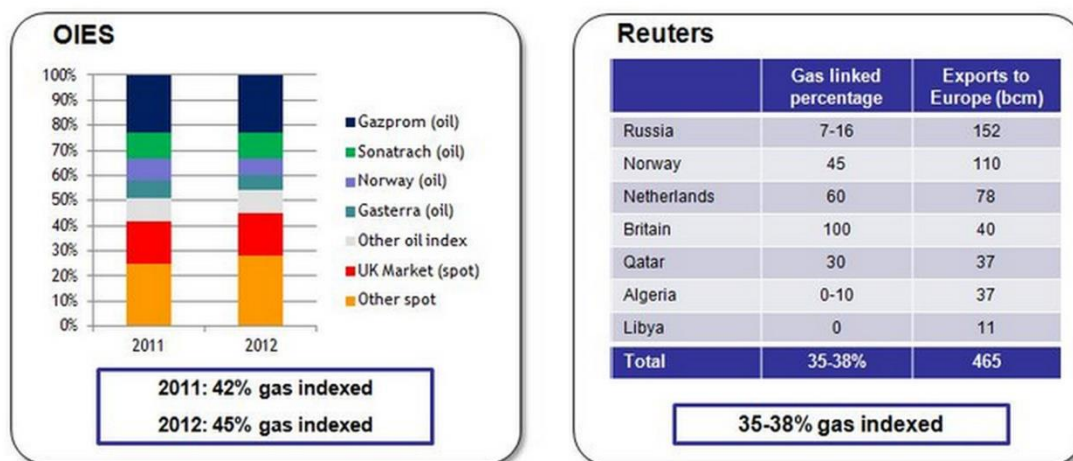
Source: International Gas Union Wholesale Gas Price Survey – 2013 Edition

It is clear that traded markets follow an upward trend while oil-indexed markets have taken a downturn. Nevertheless, despite the upward trend of the spot indexation of gas, oil indexation will most likely continue to be the main pillar for pricing gas and will co-exist with traded markets in continental Europe for years to come. The 20-30-year contracts of most European pipeline imports are still oil-indexed to a large extent. Consequently, oil-indexed

¹³ OPE: Oil Price Escalation (Oil Indexation)
 GOG: Gas-on-gas competition (Hub pricing)
 BIM: Bilateral Monopoly (price determined based on agreements between a large seller and a large buyer)
 NET: Netback from Final Product (The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces).
 RCS: Regulation-Cost of Service (The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the “cost of service”).
 RSP: Regulation-Social and Political (The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise).
 RBC: Regulation-Below Cost (The price is knowingly set below the average cost of producing and transporting the gas often as a form of state subsidy to its population).
 NP: No Price
 NK: Not Known
 (Source: IGU)

pipeline contracts are the main source of supply driving marginal pricing at hubs. Evidently, major gas producers – especially Gazprom (Russia) and Statoil (Norway) have a common interest in controlling physical flow into Europe to support hub prices at a level broadly in line with oil-indexed pipeline supply [26].

Figure 59. Two views of aggregate European supply contract indexation.



Source: Timera Energy based on data from OIES and Reuters

According to IGU, the development of “gas-on-gas competition” will most likely be benefited by the development of a global LNG market. The natural gas demand of each country will be supplied from indigenous production, pipeline imports and LNG imports. Increased shale gas production in North America and major shifts in global LNG supply patterns reflect strong interdependence between supply, demand and price in different continents [22]. LNG is the fastest-growing component of the global natural gas market, and European LNG demand is also expected to grow as a result of the decline in the production from the North Sea and the total increase in natural gas demand due to economic growth and the environmental benefits attributed to natural gas.

High LNG development costs¹⁴ will require rigid long-term agreements. Nonetheless, as projects become more expensive and buyers become more price sensitive, LNG pricing becomes more challenging. On the other hand, oil is becoming somewhat scarce and more expensive while the surplus of natural gas grows. In this context, strict oil indexation is becoming less and less attractive for buyers.

¹⁴ The huge capital cost of a ship which is a barrier to more competitors entering the industry.

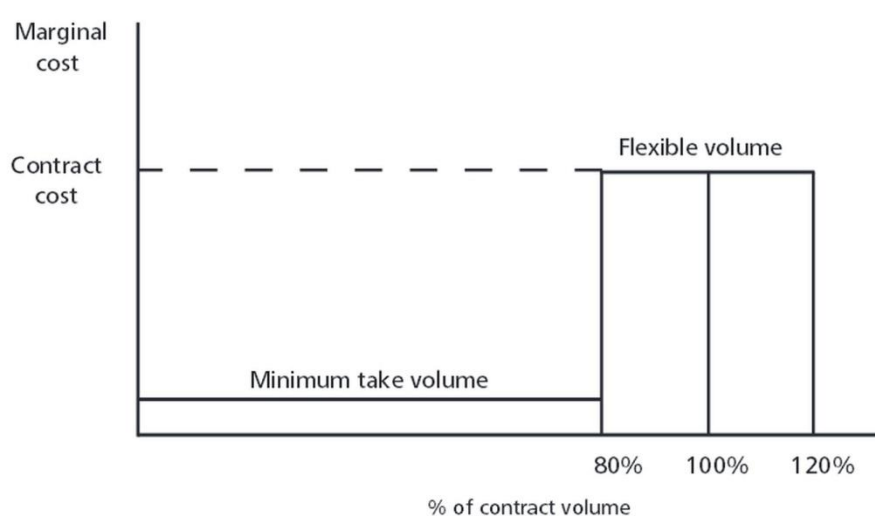
4.2. SPOT HUB PRICING VS. LONG-TERM CONTRACTS

Long-term contracts link sellers and buyers for a period of 20-30 years into a bilateral monopoly, during which both of them have specifically defined obligations. New long-term contracts often refer to a shorter period of 8-10 years. The risks are shared between the parties, with the buyer bearing the volume risk and the seller bearing the price risk. Long-term contracts provide companies that make significant investments in the extraction of gas and in the building of dedicated infrastructures, with security of demand, giving them a guaranteed source of revenue. Additionally, they provide wholesalers with security of supply and facilitate long-term energy planning [27].

In contract negotiations, gas-producing companies want deals that can support their infrastructure investments, while buyers aim at prices which can increase their market share compared to competing fuels. Oil indexation is used to a large extent in order to protect the buyer against price fluctuation relative to competing fuels, but has proven more advantageous for producers due to the high oil prices compared to the lower natural gas prices. Therefore, producers are not motivated to shift to hub-based pricing. They also hesitate to abandon well-established practices such as long-term contracts and often question a hub's ability to provide a reliable price for natural gas [6].

Long-term contracts in the gas industry typically included a 20-year term, take-or-pay (TOP) clauses and quarterly pricing adjustment based on competing fuels prices (usually oil). A TOP obligation refers to an unconditional predetermined payment, which enables the purchaser to receive a certain quantity of gas. However, minimum purchase commitments in long-term gas contracts became increasingly unmanageable as buyers were forced to pay for natural gas deliveries at much higher prices than their competitors [28].

Figure 60. Oil-price indexed contracts.



Source: Deloitte

On the other hand, sellers and buyers at spot markets can trade standardized natural gas products at a variety of delivery dates and locations, anonymously, without specific relations between the seller and the buyer. Hub trading is often used to supplement the long-term contract volumes in a portfolio, as well as to adjust a portfolio towards delivery day [29]. They now offer a realistic alternative for buyers and sellers to balance their commitments.

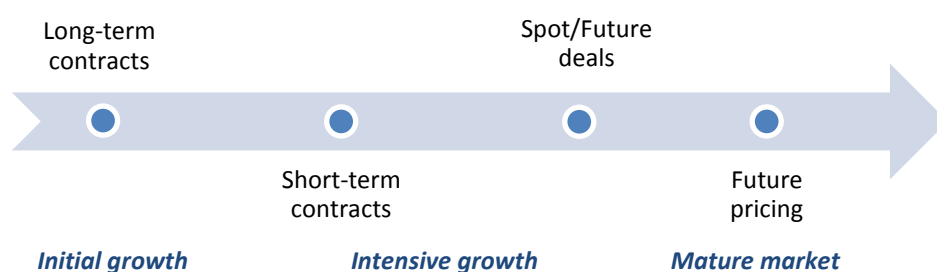
Liquidity and transparency are the fundamentals for the success of a natural gas hub. As gas market liquidity and integration increase, hub prices will reflect the EU demand and supply of natural gas and will be less vulnerable to price manipulations. As already mentioned, the usual metrics for a hub efficiency include measures of liquidity, such as the churn ratio (re-trading ratio), the number of trading parties and the depth of liquidity in the futures curve, and measures of trade concentration, such as the frequency distribution of volumes trades on an individual basis [1]. The spot market is continuously developing, both in volumes and in churn ratio and new hubs are emerging in Continental Europe. The competition between them, as well as their traded volume, is increasing.

The gas-on-gas competition pricing model demands the creation of hubs, which will function in a competitive and transparent regulatory environment. Spot transactions and futures are essential for the development of hub-based pricing. Financial trading of natural gas means that non-gas players, such as institutional investors, banks, trading firms etc. can participate in the gas market and take on gas-specific risks. As a result, natural gas futures are now the third largest physical commodity futures contract in the world by volume and continue to grow.

The futures market provides financial products based on an underlying asset price and is used to hedge physical positions. It basically allows the market participant to mitigate risk by financially hedging a future position and locking in profits. This kind of hedging is successful because futures prices are closely correlated with gas spot prices.

As the natural gas market matures (see Fig. 61), trading will increasingly be based on future pricing. These developments towards future pricing do not necessarily mean market participants will give up long-term contracts, due to their strategic importance in securing long-term supply and demand.

Figure 61. Market maturity.



Regardless of market dynamics, the role of long-term contracts is about to change because they now have to be in line with the rules integrating the EU internal gas market. Market monitoring will increase and contracts that do not meet the objectives set by the EU will not be accepted. Gas pricing mechanisms are also expected to be affected by the internal gas markets integration in the EU. Gas hub development is expected to benefit from the EU energy strategy as well. The European Commission along with the Agency for the Cooperation of Energy Bodies (ACER) and National Regulatory Authorities (NRA) will try to remove any barriers to the integration of the internal gas markets and therefore, the level of competition is about to improve [25].

4.3. GAS PRICING DISPUTES – THE ROLE OF RUSSIA

In the past few years the European gas market has emerged as the main battleground for gas pricing. On the one hand gas suppliers support the dominant gas pricing mechanism, which is oil-indexation, and on the other consumers demand the transition to the gas-on-gas competition mechanism. While oil indexation still dominates Europe's gas supply contracts, the market is shifting in favor of spot pricing. Major gas suppliers such as Russia and Qatar rely heavily on oil indexation. Great Britain and the Netherlands are the only countries where most of the gas is supplied on a spot market basis.

Long-term oil-indexed contracts usually include an adjusting mechanism to possible changes in market conditions (e.g. an unforeseen increase or decrease in demand), which is the renegotiation of contract terms and their adaptation to the market conditions. Following the shrinking of natural gas demand in 2009, the natural gas industry in Europe saw a considerable number of renegotiations [6]. Indeed, European utilities have argued against the oil-gas link, renegotiated the terms on their long-term contracts with major suppliers and achieved a reduction in contract prices. Norwegian Statoil, Europe's second-biggest gas supplier after Russia's Gazprom, now supplies almost half of its gas to Europe on a spot basis. In 2012, Norway supplied European buyers with gas at significantly lower spot-indexed prices and forced Russia to agree to a price concession and pay more than \$4 billion in 2013 in order to compensate European customers who had complained about expensive gas prices linked to the oil market. However, in 2013 Russia supplied around 133 bcm to Europe widening its lead over Norway to about 30%.

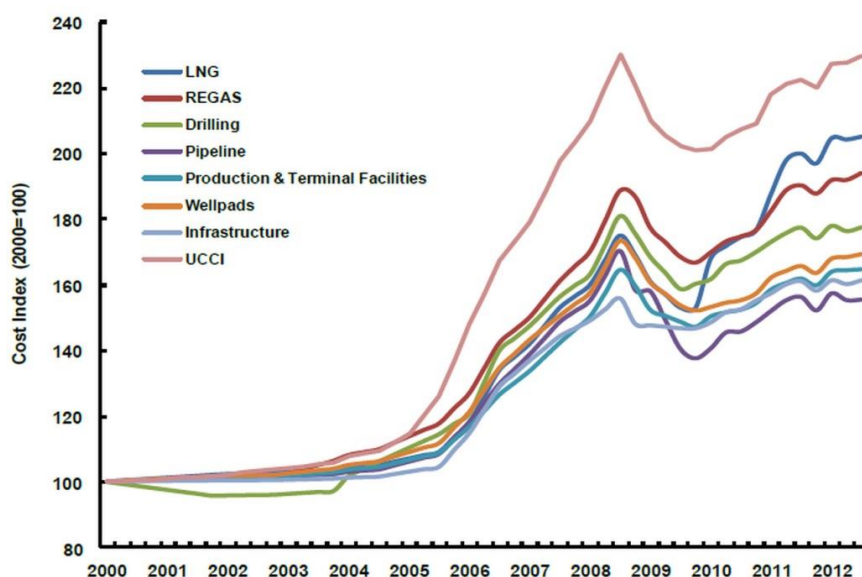
In contrast to their European customers, major gas exporters, primarily Gazprom, remain keen on maintaining the oil-gas link as the best natural gas pricing mechanism. High oil-indexed prices have threatened to reduce Gazprom's market share in the past and are likely to do so in the future, by promoting the development of shale gas in Europe and the building of more LNG import terminals.

According to Gazprom, the rising cost of natural gas exploration, production and infrastructure makes the increase of the oil-indexed gas price reasonable. As depicted in Fig. 59, upstream construction and operating costs have increased over recent years, driven

mainly by the rising costs of steel, equipment and labor¹⁵. According to IHS, upstream capital costs were estimated to increase 4 to 5% in 2013 [30]. The investment risks associated with undertaking investments of this scale are mitigated through long-term oil-indexed contracts which can lock up a satisfying return on investment. Gazprom argues that a pricing mechanism based on supply and demand is not suitable for natural gas because it does not support the necessary long-term investments.

More specifically, on its discussion paper, “Pricing the Invisible Commodity”, Gazprom states that oil indexation provides the “fair” price for gas, because oil price moves in sync with the prices of the other exchange-traded commodities and therefore, makes the price of natural gas also move along with them. On the contrary, spot prices, which tend to be 20 to 30% lower than oil-indexed prices lead to gas being undervalued. As a result, as stated in Gazprom’s discussion paper, lower gas hub prices jeopardize long-term investments of the producing companies because they “must buy the commodities necessary for those major investments at an inflated price”.

Figure 62. Growth in upstream capital costs.



Source: Gazprom Export (IHS CERA Upstream Capital Costs Index)

Nonetheless, oil and gas are two different commodities and their prices should be determined by supply and demand for each product. Moreover, prices derived from a market-based mechanism should encourage inter-fuel competition. When oil indexation was first introduced, natural gas markets were thinly traded and therefore natural gas price indexation to oil was logical. Since natural gas started playing an important role in covering the energy needs of OECD countries, it has been developing its own market fundamentals. The skyrocketing of oil prices during the last few years made natural gas prices soar in Europe, kept demand at low levels and left European utilities who had bought oil indexed

¹⁵ Upstream steel costs increased 11% between the third quarter of 2009 and the third quarter of 2012, while equipment costs increased 11% during the same period.

contracts exposed to competition. This situation resulted in an increase in arbitration proceedings¹⁶ [31].

The gas-on-gas pricing mechanism, which is basically spot pricing, can quickly adapt to rapidly changing market fundamentals. However, spot pricing does not imply that natural gas prices will necessarily be lower than oil prices, just that gas prices will be formed based on supply and demand dynamics for gas, rather than for oil. It is a common misconception that oil-linked gas prices will necessarily be higher than those set at gas trading hubs. A long-term gas contract based on the price at one or more trading hub could yield higher prices than a similar contract linked to oil prices, depending on the selection of base prices and escalators. Whether this price relationship would endure over the long term would depend on the relative tightness of the oil and gas markets. Were oil prices to collapse as a result of abundant supply (which may seem unlikely given the ongoing political problems besetting major oil producers like Iraq and Libya), at a time when incremental gas supplies were limited by delays to new LNG projects, then a situation could well emerge in which contracts with hub-based prices could provide higher prices to producers than those linked to oil.

The shift will not be immediate nor will it signify the end of long-term contracts. It is more likely that there will be a gradual but partial shift from oil indexation to spot/hub-based pricing. With gas being used increasingly in power generation, oil indexation has lost its rationale. Long-term contracts on the other hand, will still play an important role along with the spot markets.

More concisely, oil indexation of gas contracts will be meeting more and more barriers for the following reasons:

- competition between sellers increases,
- buyers become more price-sensitive,
- gas-on-gas competition becomes more intense,
- energy deregulation is promoted and
- spot-price-based LNG exports become more available [32].

Oil prices will continue to affect natural gas prices, since oil is an economical substitute for natural gas for power generators, manufacturers and large building owners, but the market shift to spot pricing is already in process. In fact, it is estimated that in 2013 more than 50% of Europe's gas was brought to market by hub-based pricing rather than oil-indexed pricing.

¹⁶ European gas contracts include an arbitration clause according to which, in the case that there is an unresolved disagreement, the parties can resort to an arbitral tribunal or and appointed expert for a decision [17].

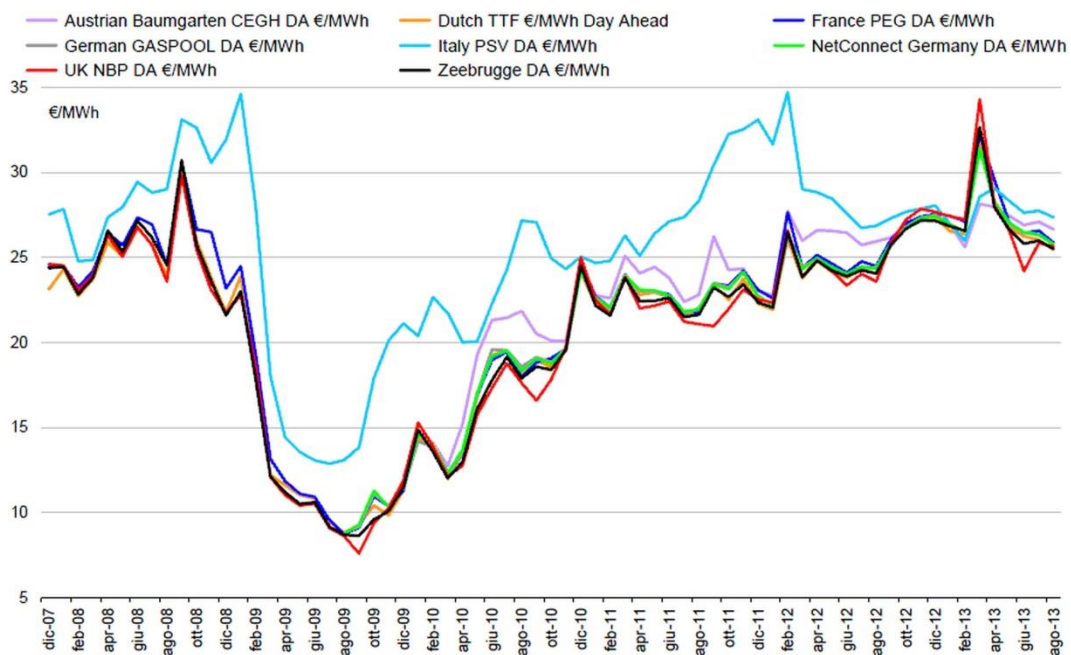
4.4. PRICE MANIPULATION AND THE OLIGOPOLISTIC NATURE OF EUROPEAN GAS MARKETS

Gas producing companies are obviously keen on maintaining oil-price indexation because they want high prices, but – as mentioned before - they are facing increased challenges from new supplies entering the market and buyers seeking better prices. However, spot trading may also have unwanted consequences. A liberalized market gives power to big suppliers. A pricing mechanism based on spot trading rather than long-term contracts would allow Russia, Europe's biggest supplier, to manipulate volumes in order to affect prices. In the natural gas global market (North America, Europe, Russia, Asia) Gazprom is the only supplier who can promptly supply volumes above current levels [31]. This implies that Gazprom would have the power to have influence on European gas hub prices by managing supplies.

A basic argument against the transition to hub-based pricing is the volatility of prices compared to oil-indexed contracts as well as the possibility of price manipulation by the suppliers or the buyers. A study performed by the Oxford Institute for Energy Studies shows that there is strong and increasing correlation between European gas prices and that the anomalies which occur are related to hub immaturity in early periods or physical connectivity constraints [1].

Price correlation between European Gas Hubs has been very strong since 2007 (see Fig. 63). Indeed, hub prices in Europe do not diverge for significant time periods. Hub prices represent market prices mainly in North Western Europe. ICIS-Heren data show some divergence in day-ahead pricing for the NBP, the TTF, the ZEE and the NCG in 2010. The divergence was more intense in September 2010 due to the closing of the Interconnector pipeline for maintenance. The Austrian CEGH and the Italian PSV prices show some divergence from the prices of the other European hubs, but in 2011 the spread between CEGH and North West European hubs narrowed significantly and by late 2012, the prices of both hubs started to move along with the other hub prices. According to the Oxford Institute for Energy Studies, most correlations seem to be strengthening year by year, while nothing suggests price manipulation.

Figure 63. European gas hubs price correlation.



Source: Sergio Ascari, Florence School of Regulation

After regulators began investigating alleged attempts by traders to manipulate ICIS Heren’s assessment of the UK’s National Balancing Point (NBP) gas price in November 2012, concerns about price manipulation still exist. However, UK’s Financial Conduct Authority (FCA) and Ofgem, the British energy regulator, have found no evidence of price manipulation. Reporting agencies such as ICIS Heren, Platts and Argus assess prices based on bids and offers from market participants. The robustness and transparency of the agencies’ methods are extremely important, because the price of natural gas affects the value of derivative contracts, which in turn affects retail prices.

Figure 64. UK gas price on the day-ahead market and alleged price manipulation (Guardian Newspaper).



Source: Timera Energy

As depicted in Fig. 64, it appears that traders executed sell orders below the prevailing market prices on 28 September 2012. The Heren index is set at the last price a product was traded. Therefore, this price behavior probably had a bigger impact on the end of day price assessment. A price based on the last trade means that it reflects more the price a product is actually valued at, while the weighted average price on the other hand, catches the entire life of a product. However, significant movements in the past can still impact the final price.

Price manipulation can occur when a trader takes a leveraged position in an instrument the value of which derives from a price index. A trader can try to manipulate a price index with a small trading volume in order to affect the value of wholesale contract volumes. The trader has a loss this way, but his loss can be outweighed by a gain in the large contract volumes with a value dependent on the index [33].

If a transaction takes place at an exchange, there is more transparency since the exchange monitors and reports market prices. Nevertheless, the exchange cannot prevent two counterparties agreeing at prices below the prevailing market and then moving forward on the transaction. As far as the Over-the-Counter trades (OTC) are concerned, involved parties are not obliged to disclose any detailed price information. Only indicative prices can be made public from OTC counterparties.

Concerns over alleged trading malpractice are enforced by the conclusion of Hegde and Fjeldstad that the majority of trading in many European hubs is done by incumbent gas companies and domestic producers [24]. This becomes more evident at the less liquid hubs in Central and Southern Europe, but can also be observed at the more liquid hubs. Nevertheless, these concerns will recede as the market liberalization process moves forward in the European Union. Hubs will gradually become more liquid and will have more market participants. As a consequence, a single trader will not have the power to manipulate prices.

THE OLIGOPOLISTIC EUROPEAN GAS MARKET

The liberalization of the EU gas sector led to a shift from national monopolies to a bilateral oligopoly, with a high degree of market concentration, where both buyers and sellers have significant market power. The supply side is dominated by three major foreign sellers (the Russian Gazprom, the Algerian Sonatrach, and the Norwegian Statoil), while the buying side is dominated by major utility companies (e.g. Gaz de France, E.ON, Eni, EDF, Enel, RWE etc.).

Price negotiations can be intense because buyers try to protect final consumers' interests. However, one could argue that there is no real competition in the European natural gas market. Prices are set competitively, but the oil-indexed contract dominance and the oligopolistic market structure have prevented the expected price behavior of a competition-based market. Oligopoly behavior with potential supply disruptions enables the producers to control prices. Significant investments in networks and gas storage capacities are needed in order to overcome competition barriers [34] [35].

Energy security has been very high on the list of the EU energy and foreign policy agenda in the last decade. The main goals of the E.U. in the energy security domain are to decrease the energy dependence of member states on as few external suppliers as possible and to

promote stable market rules which will make energy markets open and liquid. The EU aims to ensure the diversification of gas supply in order to decrease the market share of the largest foreign gas suppliers, and especially that of its biggest supplier, Russia, in an effort to shift price negotiations to the benefit of European buyers. Russian – Ukrainian tensions in 2006 and 2009 resulted in disruptions in gas supply from Russia. Particularly, the Ukraine-Russia gas dispute in 2009 caused the biggest gas supply crisis in Europe's history. Supplies to Europe were disrupted when negotiations between the two countries over gas prices and outstanding debts resulted in Russia disrupting shipments to Ukraine. In 2006 the issue was quickly resolved and supplies were restored leaving European exports unaffected. However, the tense relations between Russia and Ukraine in 2009 were intensified when Gazprom accused Ukraine of stealing millions of dollars' worth of transit supplies. Following this, all Russian gas flows through Ukraine were halted for 13 days.

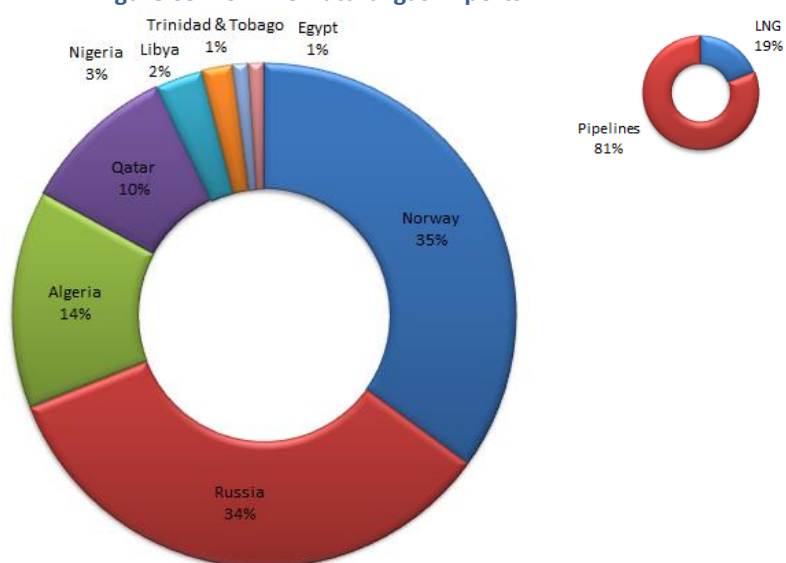
In early June 2014, Russia cut off gas supplies to Ukraine in response to the Kiev government's failure to pay for past deliveries. The cut-off of supplies was quickly followed by an explosion on one of the transit gas pipelines across Ukraine carrying gas to Europe. The availability of spare capacity along alternative routes meant that there was no disruption to Russian gas deliveries to Europe. Neither Russia nor Ukraine has anything to gain by disrupting deliveries to Europe, unless it can convincingly blame the disruption on the other party.

Ukraine is by far the most important transit country for Europe, since it transports the biggest volume of gas destined for Europe (about 20% of Europe's gas supply). If Gazprom and the Russian Federal Government were to have their way, this could change in the future. The construction of bypass capacity beneath the Baltic Sea (55 bcm/yr already operating and a similar additional capacity proposed through Nord Stream) and the Black Sea (63 bcm/yr of capacity planned through South Stream) would, in time, allow Gazprom to end the transit of gas to Europe across Ukraine. According to data published by the Ministry of Energy and Coal Industry of Ukraine, 86 bcm of Russian gas transited the country in 2013, a volume that could easily be diverted via Gazprom's proposed Nord Stream and South Stream pipelines.

5. POTENTIAL SUPPLIERS OF THE EUROPEAN GAS MARKET AND THEIR ROLE IN MARKET LIQUIDITY

In 2012 roughly 80% of the EU gas import was based on pipeline gas, while the rest was LNG. Pipeline imports will continue to dominate EU supplies, especially because a large part of LNG supplies will be absorbed by the energy-hungry Asian markets. Europe remains the second-largest LNG importer behind OECD Asia Oceania. Net natural gas imports in Europe are expected to increase by 36 bcm to 277 bcm by 2018. According to the 2013 IEA Medium Term Gas Market report, around 70% of OECD Europe imports will still be based on pipeline gas in 2018 and Europe's only additional source of supply will be Russia due to the absence of any alternatives able to provide significant volumes. LNG imports are expected to become more available after 2015 [36].

Figure 65. 2012 EU natural gas imports.



Source: BP Statistical Review of World Energy 2013

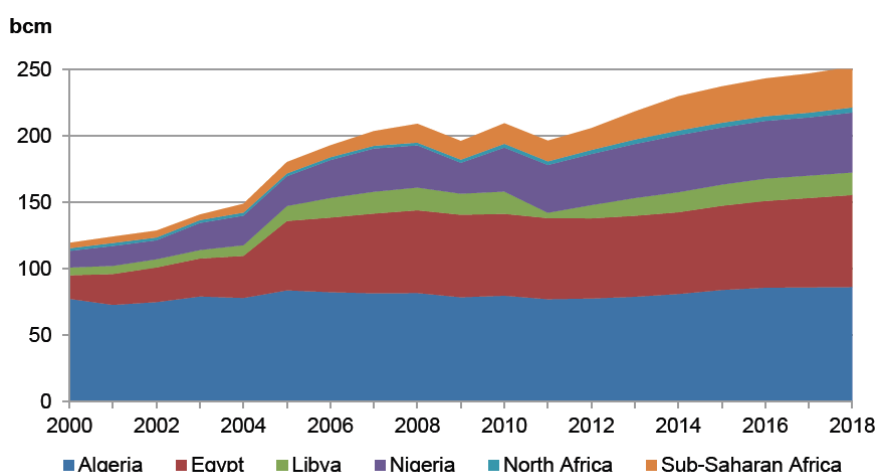
Natural gas is a vital component of the EU energy mix and will undoubtedly continue to play an important role in EU's energy strategy. As already mentioned, energy security concerns have been expressed about possible curtailment in Russian gas supplies. The EU is currently looking to diversify supply 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 by the end of 2014. 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.

5.1. NORTH AFRICA

The Middle East and North Africa (MENA) are the two regions which together account for around 40% of the world's proven gas reserves. North Africa remains the continent's leading region for natural gas production. It has been a traditional gas supplier to Europe and accounts for 20% of EU-27 natural gas imports. 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 66. African gas production, 2000-2018.



Source: IEA

All in all, North African gas is not expected to bring significant additional volumes to Europe, since the fast-growing domestic demand will absorb the increase in gas production.

Moreover, the future of African gas is expected to shift towards the East due to the huge recent discoveries in offshore East Africa, specifically Mozambique and Tanzania [37]. Nigerian gas production is also expected to rise significantly, taking a position as the third-largest African producer. Nigeria's proven natural gas reserves were estimated at 5,2 tcm at the end of 2012, while the Nigerian National Petroleum Corporation (NNPC), the country's national oil company, estimates its unproven gas potential at 18 tcm [38].

Table 20. Key North African natural gas data in 2012 (bcm).

	Reserves	Production	Exports to EU
Algeria	4.502,53	82,07	48,1
Egypt	2.037,6	62,26	2,83
Libya	1.545,18	11,32	5,66
Total	8.085,31	155,65	56,6

Source: BP Statistical Review of World Energy 2013

5.1.1. ALGERIA

Algeria is the third-largest supplier of natural gas to the European Union, after Russia and Norway. According to the BP Statistical Review, Algeria's proven natural gas reserves corresponded to 4,5 tcm in 2012. At current production levels, this would provide output approximately for another 60 years.

Algeria announced in February 2012 that it has important shale gas potential that could be equal to that of the United States. According to EIA estimations, Algeria has around 6,93 tcm of recoverable shale gas reserves. Nonetheless, exploratory work on Algeria's unconventional reserves is still at an early stage and the commercial viability of the reserves is not fully determined yet. Production is unlikely to start within the next decade.

The Algerian gas sector is generally open to international competition. Sonatrach, the national hydrocarbon company, has the right to keep at least 51% interest in all new projects and has extensive investment plans over the next five years. However, the country's difficult business environment constitutes a threat for the sector's potential. The latest developments, such as US shale gas production, the rise of new LNG exporters, and the decreasing demand for Algerian gas in Europe, pushed the Algerian government to advance its energy strategy. The Algerian government now aims to expand its gas reserves and infrastructure for exports. In January 2014 Algeria's state oil licensing body, Alnaft, announced a new bid round with 31 blocks open for bidding, that will open up new regions in the southwest and northern parts of the country. New regulations were designed, in order to make the exploitation of unconventional gas resources, such as shale gas, more attractive [37].

Algeria traditionally uses long-term supply contracts. Lower spot prices have been putting pressure on Algeria's oil-indexed prices and there is a concern that European customers may wish to change the existing pricing formula in order to achieve lower contract prices. On the other hand, Algeria will most likely try to maintain the existing pricing regime in

exchange for security of supply via pipelines and LNG delivery. However, this may turn out to be a challenge for Algeria, at a period when European demand is low and domestic demand is increasing. A disruption of Algeria's gas industry or exports would create serious problems for Algeria – due to the country's heavy economic dependence on its energy sector – as well as for Italy, Spain, and France, the major European importers of Algerian natural gas. In view of the development of unconventional gas resources, traditional gas producers such as Algeria may seek to increase their own exports even at lower prices. If these market trends continue, it is very likely that Algeria will try to find alternative markets, while the decoupling of natural gas prices from oil prices will increase [39].

5.1.2. EGYPT

Egypt is Africa's second largest natural gas producer. The Suez Canal, a 163-km link between the Red Sea and the Mediterranean, and the 320-km Sumed pipeline are strategic transit routes for Persian Gulf oil and gas shipments to Europe and North America. Egypt's gas exports to the EU are in the form of LNG. Egypt has two LNG plants, Damietta and Idku. In 2010 Egypt's gas exports to the EU decreased by 35%, while in 2011 they decreased by 12%, as a result of a government decision to enact a two-year moratorium on new gas export deals in 2008 due to the growing domestic demand for natural gas and the low international gas prices at the time. LNG exports are expected to decline further in 2013 because increased local demand has absorbed the additional natural gas supply.

Egyptian proven gas reserves correspond to 2 tcm and could cover the country's energy needs for many years to come. However, due to the increase in domestic demand, existing export commitments and delayed gas explorations, Egypt is now experiencing nowadays a natural gas crisis. According to BG Group, the British oil and gas producer, which announced on January that it broke contracts with customers and lenders because it was unable to export enough LNG from Egypt, gas exports fell because the Egyptian government, which has to deal with social unrest, had ordered the diversion of the company's natural gas production to domestic purposes. Therefore, Egypt is not expected to export any gas in the short to medium term, at least as far as its own production is concerned. Nevertheless, Egyptian LNG facilities could use Israeli gas to export LNG, but this would take 3-4 years to happen, if agreed.

Egypt's state-owned Egyptian Natural Gas Holding Company (EGAS) issued a tender for a floating storage and regasification unit (FSRU) in 2013, which was planned to start operation by April 2014, in order to meet rising demand. Its construction has experienced delays and it is now estimated that it will not start operation before summer 2014. Furthermore, the Norwegian firm awarded the project rejected the commercial terms, making it more difficult for the Egyptian government to deal with the already acute shortages. Indeed, according to government estimates, production will fail to meet the domestic demand in the next fiscal year. The country's political turmoil is aggravating the situation even more.

Egypt's energy insecurity currently affects its consumers, the local industry, as well as the Egyptian economy in general. According to analysts, energy imports would send a negative

signal to foreign firms, which are becoming increasingly reconciled to the prospect of LNG exports halting entirely this summer. Nevertheless, it is estimated that unless Egypt handles the issues blocking gas production by foreign companies, it will inevitably have to import increasing volumes to meet own rising energy needs.

5.1.3. LIBYA

With the development of offshore fields and the opening of the Greenstream pipeline to Europe, Libyan natural gas production and exports increased after 2003 [40]. The Marsa El Brega LNG terminal Libya ceased to export LNG in 2012 after the 2011 crisis, and is assumed de-commissioned [41]. During 2011's civil war, Libya's natural gas production and exports were suspended. However, since the end of 2011, gas production has been restored and is now close to pre-crisis levels.

According to the 2013 BP Statistical Review, Libya's proven natural gas reserves corresponded to 1,5 tcm at the end of 2012. The Libyan National Oil Corporation (NOC) has stated that Libya's gas reserves are "largely unexploited and unexplored". Libya may truly have a significant potential to increase its natural gas exports if natural gas exploration is boosted. Nevertheless, local demand for electricity generation may boost domestic demand for natural gas.

5.2. CASPIAN SEA REGION AND CENTRAL ASIA

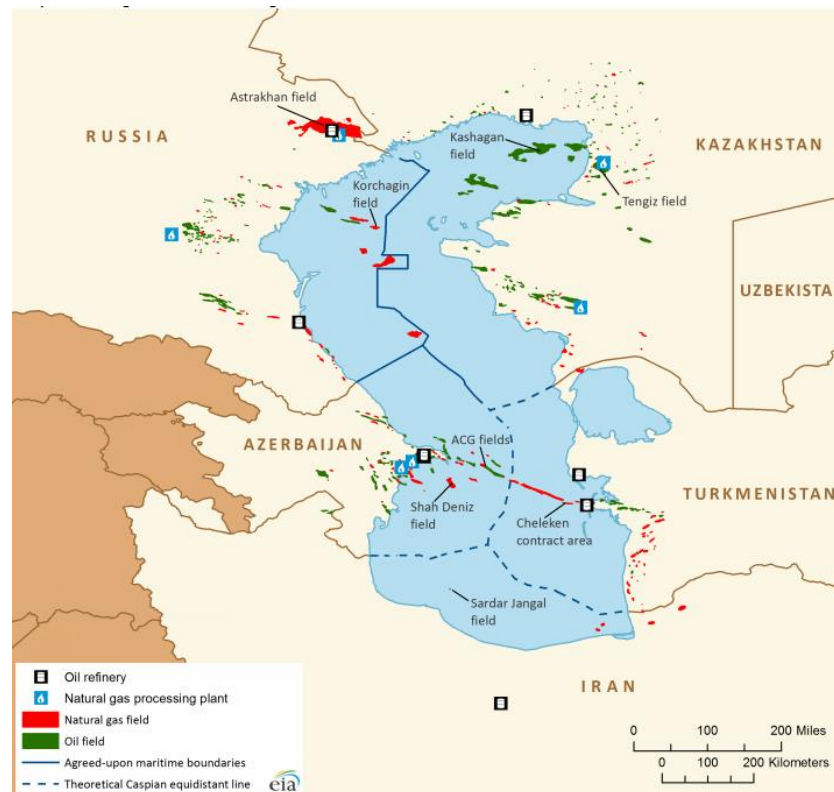
The European Commission welcomed the final investment decision (FID) on extracting gas from the Shah Deniz II gas field in Azerbaijan in December 2013. This FID will eventually open the Southern Gas Corridor and will bring Europe closer to its goal of diversifying natural gas supplies by ensuring that gas will be transported from the Caspian Sea region to Europe, specifically Central Europe and South Eastern Europe, which depend solely on Russia for gas supplies. Starting from end 2019, Europe will obtain 10 bcm of gas per year from the Caspian Sea region, starting with Azerbaijan. At a later stage and provided that the necessary infrastructure is in place, gas can be exported to Europe also from Kazakhstan, Turkmenistan, Uzbekistan and Iran.

Azerbaijan's proven natural gas reserves are about 0,9 tcm, most of which are found in the Shah Deniz field. Kazakhstan's total proved gas reserves correspond to 1,3 tcm, while Turkmenistan and Uzbekistan have 17,5 and 1,1 tcm of total proved gas reserves correspondingly [42]. Kazakhstan and Uzbekistan however, utilize most of the gas they produce domestically. Russia of course, has the largest gas reserves in the region. Nonetheless, a significant part of the expected gas flows towards Europe are expected to be absorbed by the energy-hungry Turkish market, as an annual output of 16 bcm/yr has already been contracted from Shah Deniz II.

The region's strategic location between both Europe and Asia renders it attractive for energy investments by a variety of international companies. The ability of the Caspian Sea

region countries to export greater volumes of Caspian natural gas will depend on the investment attractiveness of gas production projects, the development of export infrastructure, as well as the domestic energy demand rate of increase.

Picture 28. Caspian Sea region oil and natural gas infrastructure.



Source: EIA

Today Central Asian supplies must pass through Russia to reach Europe. A number of pipeline projects have been under discussion, but the development of Southern Corridor pipelines is very slow. Due to these delays, Europe will have to compete with Asian markets, as Central Asian countries are forced to look for new markets in the East. The pipeline projects which are already well underway or at least show a very good possibility of realization are the Trans Adriatic Pipeline (TAP), the Trans Anatolian Natural Gas Pipeline Project (TANAP) and the Expansion of the South Caucasus Pipeline:

- The TAP project defeated the Nabucco West pipeline to carry gas from Shah Deniz II from Turkey's western border to Europe, because according to analysts, it is 450 km shorter than the proposed Nabucco pipeline, while market tests delivered highly competitive purchase prices by several European utilities and traders. Natural gas will be transported from the Shah Deniz field in Azerbaijan, crossing Greece and Albania, before ending in Southern Italy. Work on the TAP is expected to start in 2015 and the pipeline will become fully operation in 2019.
- The TANAP is expected to start carrying 16 bcm of gas a year in 2018 or 2019 from the Shah Deniz II field and will be built from the Turkish-Georgian border to Turkey's

border with Europe. It is expected that construction work on TANAP will start in early 2015.

- The 692km South Caucasus Pipeline has been designed to transport gas from the Shah Deniz field in the Azerbaijan sector of the Caspian Sea, through Georgia and on to the Georgia-Turkey border. The expansion of the South Caucasus Pipeline is part of the Shah Deniz Full Field Development project. According to BP, this expansion includes the laying of new pipeline across Azerbaijan and the construction of two new compressor stations in Georgia and is expected to triple gas volumes to over 20 bcm per year [43] [44].

Picture 29. Southern Corridor.

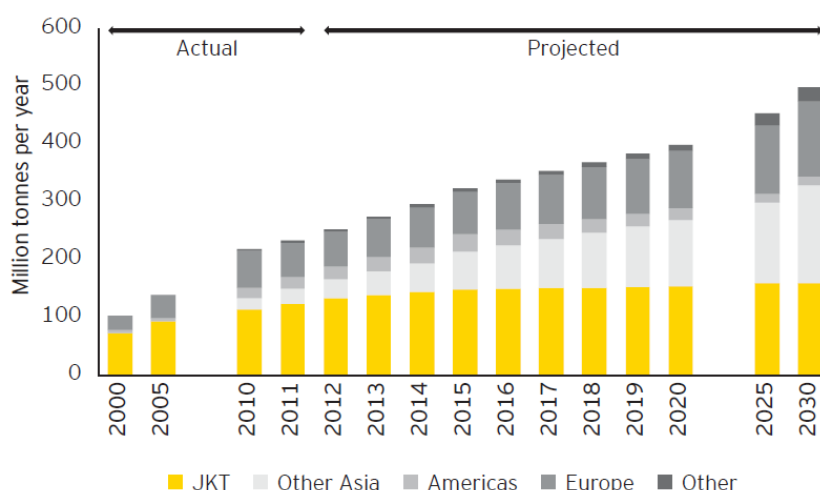


Source: The European Institute

5.3. LNG IMPORTS

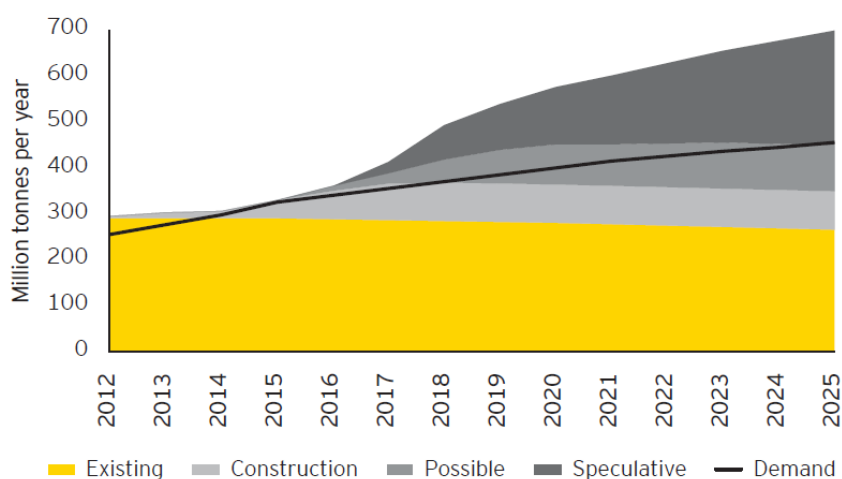
In 2012, LNG comprised 19% of the EU's total natural gas imports and 5% of total EU consumption. LNG demand is expected to grow, particularly through 2020. The average annual growth is estimated by industry analysts at approximately 5% to 6% per year. After 2020, LNG demand is expected to continue growth at a slightly slower pace (2% to 3% per year). 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.

Figure 67. Actual and projected global LNG demand.



Source: Ernst & Young

Figure 68. Global LNG capacity and demand.



Source: Ernst & Young

LNG imports offer an important alternative to natural gas imported by pipeline from Russia. Several countries are considering the construction of LNG terminals in order to reduce the dependence from single sellers and diversify their natural gas sources. Currently, EU LNG facilities are underutilized during most of the year. The EU could use gas storage facilities for import capacity management throughout the year. It should be noted that the existing capacity of EU LNG facilities can satisfy peak winter demand.

In the longer term, US LNG could also play an important role in European energy security. Companies wishing to export LG from the US require a range of permits from the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC), with different criteria for exports to countries with which the US has a free trade agreement and those with which it does not. Today several US LNG export projects are under consideration and one is under construction, due to come into operation in 2015. In fact, the US Department of Energy has approved seven such applications, for a total amount of 9,27 billion cubic feet per day (Bcf/d) of exports, which corresponds to more than 12,5% of current US natural gas production. The potential participation of the United States in the

global LNG market is expected to affect natural gas pricing globally, reducing the price differential between LNG in Europe and in Asia. US LNG production will therefore, offer an additional source of gas supply and can lead to a decrease in natural gas prices. Moreover, since US natural gas prices are not linked to those for oil, significant volumes of LNG exports from the US would put additional pressure to traditional sellers like Russia, to delink the two fuels [45]. US LNG will be sold by private companies driven to maximize their profits and there is no guarantee that large volumes of US LNG will be exported to Europe if better returns can be earned from sales to Asian buyers.

Furthermore, East African countries, particularly Mozambique and Tanzania, present new opportunities as somewhat underexplored areas with resource potential. Although the US EIA reports that gas reserves of Mozambique amounted to 4,5 tcf and those of Tanzania amount to only 0,23 tcf in 2013, recent discoveries indicate that these numbers will increase. Anadarko Petroleum Corp., an American oil and gas exploration company, has discovered recoverable gas reserves of 50-70 tcf, while Italy's Eni projects that it has around 93 tcf of recoverable natural gas. Eni has also announced that it plans to build an onshore LNG plant and two floating LNG plants in Mozambique's Mamba field with a combined capacity of 10 million tonnes per annum (mtpa). A final investment decision (FID) is expected in 2015, while production is due to start in 2020.

Tanzania's estimated reserves are smaller but still significant. The latest estimates indicate that there are total recoverable gas resources amounting to 23-26 trillion cubic feet (tcf). The resource exploration and appraisal is still ongoing. However, the British BG Group and the Norwegian Statoil have announced their plan to build an LNG export terminal which is expected to start production after 2020, while a final investment decision is expected in late 2016.

According to the US EIA, Angola, the second largest proven natural gas reserves in sub-Saharan Africa after Nigeria, had approximately 12,9 tcf in proven natural gas reserves in 2013 [46]. The LNG processing facility in Soyo, the largest investment ever made in Angola, will have a capacity of 6,8 bcm/yr at full production. The main focus for LNG exports will be drawn to Asian and European markets, although they were originally focused on the US market. However, the growing US shale gas production US lead to a decrease in US gas prices and forced the Angola LNG project partners to negotiate new contracts aiming to find markets with higher prices [39]. In June 2013 the first cargo was shipped to Japan, but only 10 cargoes since it started up. The LNG facility has been recently forced to shut down due to technical issues which have caused an unplanned interruption to production and according to Minister Jose Maria Botelho de Vasconcelos will remain offline until 2015 to allow its contractor, Bechtel, to make repairs and increase capacity at the plant.

Finally, the role of Canada has emerged, as an LNG supply source for Europe, as the German company E.ON confirmed in June 2013 that it agreed with Canada's Pieridae Energy to purchase 5 million tons of LNG annually for 20 years starting in 2020. Also, Spanish Repsol SA is considering building a \$2 billion plant at its existing Canaport facility in order to export natural gas. The Canadian government intends to back LNG projects on the East Coast, which will increase the competition between Canada and the US for a larger share of the European gas market.

5.4. EASTERN MEDITERRANEAN REGION

Discoveries of natural gas in the eastern Mediterranean region have reshaped the regional energy map¹⁷. The first significant natural discovery was made in 2009, when the U.S. energy company Noble Energy announced the discovery of the Tamar field in offshore Israel (250 bcm). The Tamar field discovery was followed by the discovery of the much bigger Leviathan field (476 bcm) in offshore Israel in 2010 and the Aphrodite field (140-220 bcm) in offshore Cyprus in 2011.

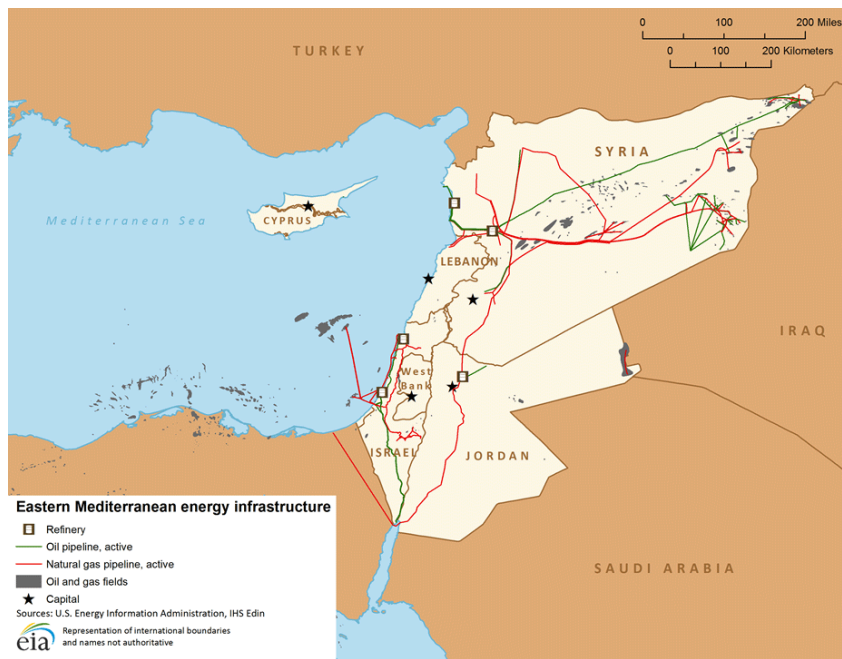
According to the Cyprus Energy Department, the country's offshore territory could contain as much as 1.700 bcm. Natural gas reserves in the region are relatively insignificant on a global scale, but could contribute in the diversification of gas supply sources of the EU, as well as boost the economies in the region. In June 2013, Cyprus and a U.S.-Israeli partnership, including Noble Energy, signed a memorandum of understanding (MOU) to construct natural gas facilities for both domestic consumption and export.

Currently, no countries in the region export natural gas. Israel will most likely start exporting gas to Egypt as early as the second half of 2014. Natural gas development in the region is expected to encounter several challenges. Major investments in infrastructure for natural gas transfer and processing will be required. The setting of environmental and safety regulations could also prove challenging. Additionally, in order to export gas new infrastructure would also have to be laid by developers and the governments of the region. Natural gas can be exported either in liquid form or via pipeline. The construction of a subsea pipeline to Greece is a possibility, but would also be very costly because of the technical difficulties involved. The proposed East Med gas pipeline would link Israel and Cyprus to Greece and Italy, but is an option that does not appear to be viable.

Local objections and disputes may jeopardize the construction of gas facilities in the region, as was the case with the Dor Beach natural gas entry point, the construction of which was cancelled. Currently, Cyprus neither produces nor consumes any natural gas. Petroleum products cover 98% of the country's total primary energy demand. The gasification of the Cypriot economy is a key priority of the government, which hopes that its newly found natural gas resources will suffice to cover domestic demand and reduce its dependence on imported petroleum products. Nonetheless, the current debt crisis could undermine demand and threaten the viability of the planned infrastructure projects. As far as the proposed LNG liquefaction facility of Vassilikos is concerned, where gas from Cypriot and Israeli gas fields would be brought for liquefaction, it is far from certain to materialize, unless additional reserves are discovered in the exclusive economic zone of Cyprus.

¹⁷ Cyprus, Israel, Jordan, Lebanon, Syria and the Palestinian Territories.

Picture 30. Eastern Mediterranean energy infrastructure.



Source: EIA

Israel was the region's second-largest natural gas consumer in 2011. The discovery of its two massive offshore natural gas reservoirs, Tamar and Leviathan, ensured that even with local demand rising, Israel can meet its own gas needs for several decades, as well as becoming a natural gas net exporter. However, there are concerns over how much natural gas the country will be able to export considering the high projected domestic demand. The Tamar natural gas production platform went into production in April 2013 and according to analysts increased Israel's GDP by almost 0,5%. It is projected to increase further the GDP by 1,5% in 2014.

The discoveries in Cyprus and Israel have shown the potential for offshore natural gas production in the eastern Mediterranean and have sparked a flurry of interest in potential natural gas reserves specifically in Syria and Lebanon. Syria launched a licensing round for offshore blocks in 2011, but exploration is postponed indefinitely by the government due to the ongoing conflict in the country. The unstable security environment in Syria, as well as the ongoing territorial disputes of the region, can undermine the success of the exploration activities. Syria does not currently possess the ability to export LNG, nor are current natural gas production levels sufficient to justify exporting volumes via pipeline. Moreover, the Syrian conflict could impair natural gas demand and interrupt production.

Lebanon has no proven gas reserves and exploration is in the early stages. The conflict between government and opposition forces has prevented the launching of an offshore licensing round despite the optimism of government officials about significant potential discoveries in the country.

Discoveries of offshore natural gas reserves will help ensure the energy security of the region as well as stimulate economic growth. However, relations between several eastern Mediterranean countries are tense and the ongoing territorial disputes could undermine

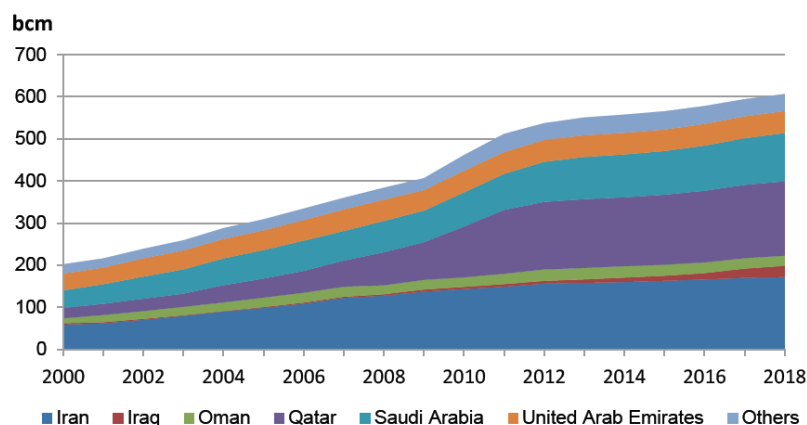
exploration and development in the region - particularly in the offshore Levant Basin - and limit cooperation over potential export projects. Eventually, the extent of natural gas development in the area will depend on regional political dynamics.

5.5. MIDDLE EAST

According to the BP Statistical Review, Middle East gas production increased by 30 bcm between 2011 and 2012. 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. According to the IEA Medium Term Natural Gas Report for 2013, gas production in the Middle East has increased by 200 bcm over the period 2006-2012 [47]. This increase can be attributed to the LNG capacity expansion in Qatar (by 70 bcm), Oman (5 bcm) and Yemen (9 bcm) and the increase in domestic demand. The IEA projects the Middle Eastern gas production will reach 607 bcm in 2018, from 537 bcm in 2012. Nevertheless, LNG exports from the Middle East actually dropped in 2012 as all LNG suppliers - with the exception of Qatar - reduced their exports. For the time being, the region is the world's largest LNG supplier (40% of global LNG supplies), but it could be overtaken by both Australia and North America, if LNG projects in these regions go ahead as planned.

Production in the Middle East is affected by many factors, ranging from security to price regulation. However, the IEA estimates that incremental supply will exclusively be absorbed by regional demand. Hence, the production boost in Middle East is driven by domestic demand, not by export requirements.

Figure 69. Gas production in the Middle East, 2000 – 2018.



Source: IEA Medium Term Natural Gas Report 2013

Despite Iran's enormous natural gas reserves, which amount to 33,6 tcm according to the BP Statistical Review of World Energy 2013, the country has been a net importer since 1997. Iran has failed to become a major gas exporter, despite its numerous announced export plans. Iran could be a potential gas supplier for Europe, but currently, pipeline projects which originate from Iran are not fully developed as to facilitate gas exports (via Turkey). Iran is also the world's third largest natural gas consumer. Gas demand is projected by the IEA to increase by 16 bcm by 2018. Therefore, the country needs to invest further in order

to create an export capacity which can ensure that the increase in natural gas production will be at a faster rate than the rise in the local demand [48].

In July 2011, Iran, Iraq and Syria signed a Memorandum of Understanding for the construction of a gas pipeline project that would transit gas from Iran's South Pars field to Greece and elsewhere in Europe, via Iraq, Syria and Lebanon, with a possible transit capacity of 110 mcm of natural gas per day. The implementation of the project has ceased, due to the conflict and lack of security in Syria. However, Deputy Oil Minister for International Affairs of Iran, Ali Majedi, stated on May 5 this year that if the situation in Syria returns to normal, the project will materialize.

As far as Qatar is concerned, six LNG mega-trains and the Pearl GTL project were completed over the past few years adding 80 bcm to production capacity in total. Qatar was the world's fourth largest dry natural gas producer in 2012 (behind the United States, Russia, and Iran), having also risen as the world's leading LNG supplier [49]. As far as the Barzan offshore project is concerned, Qatar's RasGas Company announced that four offshore platform topside modules have been successfully installed, which marks more than 80% completion of the project's offshore and onshore construction. The project's output is estimated at 14 bcm annually, but it will be used to cover the domestic needs of the power sector and the industry.

Saudi Arabia's natural gas production remains limited, although it has significant untapped natural gas potential, as its gas reserves amounted in 8,2 tcm at the end of 2012 [42]. Saudi Aramco has accelerated its gas development programme in the Persian Gulf, with major gas development projects under way. The Al Wasiit Gas Program alone is estimated to increase Saudi Arabia's gas production capacity by 21%, while production from the Wasiit and Karan gas fields together are expected to increase Saudi Aramco's gas output by 40%.

5.6. A POTENTIAL EU SHALE GAS INDUSTRY

According to an assessment of technically recoverable shale oil and gas resources performed by the U.S. Energy Information Administration, Europe's technically recoverable shale gas resources – including Ukraine - were estimated at 624 tcf. However, in 2013 the US EIA revised its assessment of Europe's shale gas resources, with the new estimate being 883 tcf [50]. The countries with the biggest estimated reserves in Europe are Russia (285 tcf), Poland (148 tcf), France (137 tcf) and Ukraine (128 tcf). Europe's shale gas production is still zero as there has not been enough shale gas exploration and it is not certain that the US experience can be implemented in Europe, since the petro-physical properties of shale gas differ from one rock formation to another [51].

The most common method of shale gas extraction is hydraulic fracturing i.e. the injection of high-pressure streams of water into rock formations, creating fissures through which trapped gas can be collected. Nevertheless, the potential risk of groundwater pollution and earthquakes attributed to this approach led the constitutional court of France to ban

hydraulic fracturing. Bulgaria was the second country after France, to ban this method. On the other hand, Ukraine has signed a \$10 billion shale gas production-sharing agreement with U.S. Chevron to develop the Olesska block in Western Ukraine, as well as with Royal Dutch Shell, in order to develop its Yuzivska field in East Ukraine. Poland had hoped to begin shale gas production by 2015, but the American technology used to extract shale gas did not prove successful in Poland, as 30 to 40 wells were planned for 2013, but only one well could produce enough gas to be economically viable.

Shale gas remains a controversial issue for Europe. Further exploration is needed to define whether shale gas exploitation is economically feasible in the continent. Indeed, the majority of industry observers estimate that shale gas production in Europe could not reach commercial levels for at least another 10 years [51].

6. SE EUROPE AS A GAS TRANSIT REGION

6.1. 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 (Iraq). According to the current state of play in South Eastern Europe, forecasts predict that the demand will grow up to 2025 at a rate of 1% each year.

Six of the SE European countries (Greece, Croatia, Bulgaria, Romania, Turkey and Serbia) already use natural gas, having well established 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 (Croatia, Romania) and three others cover small percentage shares from domestic gas (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.

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 10,9 bcm annual production (2012), while the consumption of the SE region (excluding Turkey) is around 26,6 bcm (2012). The three most gas dependent countries of the SE European region

are Turkey, Bulgaria and Greece. Indigenous production in SE Europe (excluding Turkey), at 13,5 bcm/yr, is sufficient to cover around half of current demand of 26,6 bcm (2012). 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.

6.2. REGIONAL GAS FLOWS

Greece

Gas imports account for about 100% of the total volumes of consumed gas in Greece. Most of Greece's gas imports are being realised via pipeline, and 29% is imported via LNG through the Revithoussa LNG terminal. Greece's gas pipeline imports come mainly from Russia (2,3 bcm) and a small portion of 0,6 bcm from Azerbaijan through Turkey, while most LNG originates from Algeria and Qatar (1,3 bcm). The share of Russian gas in Greece's gas imports contracted to 55% in 2012. Greece has an extensive portfolio of energy exploration projects for the future, though the present financial crisis has put a damper on these for now. Greece's domestic natural gas consumption is steadily increasing - from 2,0 bcm in 2000 to 4,2 bcm in 2012 according to DESFA - but there was a decrease in 2013, as total demand reached 3,6 bcm.

Table 21. Greece: Natural Gas Consumption 2010-2013.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2010	70,81	29,19	3,651
2011	75,26	24,74	4,591
2012	70,72	29,28	4,219
2013	84,67	15,33	3,641

Source: IENE

The demand is likely to reach 5,0 bcm by 2020 according to DESFA estimates as shown in the following table.

Table 22. Greece: Natural Gas Consumption Forecast for 2014-2023.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2014	85,12	14,88	3,399
2015	82,91	17,09	3,522
2016	78,69	21,31	4,107
2017	76,70	23,30	4,368
2018	74,19	25,81	4,650
2019	78,75	21,25	4,508
2020	75,94	24,06	4,806
2021	84,35	15,65	4,446
2022	82,97	17,03	4,580
2023	80,57	19,43	4,779

Source: IENE

Bulgaria

During the years 2010 – 2011 natural gas demand in Bulgaria showed a significant increase compared to 2009. In 2009 Bulgaria consumed almost 2,3 bcm. 0,2 bcm of its total consumption were covered by indigenous production, while the rest was imported from Russia. In 2010 the consumption of natural gas in Bulgaria increased to 2,6 bcm, while in 2011 a further increase was noted to 2,99 bcm. In 2012 there was a small decrease compared to 2011, as total gas demand reached 2,75 bcm, while in 2013 there was a small increase to 2,81 bcm. Most of the natural gas consumed in Bulgaria is used to satisfy industrial and public sector needs, although a significant proportion is used for power generation.

Table 23. Bulgaria: Natural Gas Consumption 2010 – 2013.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2010	100	0	2,66
2011	100	0	2,99
2012	100	0	2,75
2013	100	0	2,81

Source: IENE

The forecasts are that during 2014 - 2025 the demand for natural gas will rise on average by approximately 3,2% per year, reaching 6,0 bcm by the end of the period.

Table 24. Bulgaria: Natural Gas Consumption Forecast for 2014 – 2023.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2014	100	0	2,9
2015	100	0	3,5
2016	100	0	3,9
2017	100	0	4,0
2018	99,5	0,5	4,2
2019	99,3	0,7	4,4
2020	99,3	0,9	4,7
2021	98,8	1,2	5,0
2022	98,6	1,4	5,1
2023	98,3	1,7	5,4

Source: IENE

Croatia

It seems that gas production will peak over the next five years, with production expected to rise from 1,61 bcm in 2012 to 2,5 bcm in 2018.

Natural gas is produced in Croatia from 16 on-shore and nine off-shore gas fields and is currently meeting 46% of total domestic demand according to the Ministry's 2013 annual energy report. Consumption is also set to rise, from 2,82 bcm in 2012 to 3,7 bcm by 2017. Investment activities so far have focused on the completion of the development - investment cycle of the gas transmission system, as well as on the preparation of the new projects such as the planned LNG Terminal on the island of Krk. This LNG terminal, named

Adria LNG, is a proposed liquefied natural gas (LNG) regasification terminal in Omisalj on the island of Krk. The project was first considered in 1995, when initial exploratory work was undertaken. A feasibility study was completed by 2008 and the location permit was issued in 2010 after environmental impact assessment was carried out. The terminal will provide additional source of natural gas for the Croatian market. The terminal will also be a distribution point for natural gas to the surrounding market, including Italy, Austria, Hungary, Romania and Slovenia. For this purpose, a new natural gas pipeline between Croatia and Hungary was built.

Almost all of the gas quantities imported in Croatia are delivered via pipeline and mainly come from Russia. In 2012, 96% of Croatia's gas imports originated from Russia, while the remaining 4% of imported gas originated from various countries. So far, there are no LNG imports.

Romania

According to the BP Statistical Review, Romania's natural gas reserves amounted to 0,1 tcm at the end of 2012. In the same year, Romania imported 2,6 bcm of natural gas, representing 15,5% of its domestic consumption (13,5 bcm), while domestic production remained steady at 10,9 bcm.

Almost all of the gas quantities imported in Romania are delivered via pipeline, as there are no LNG import facilities. The vast majority of the gas pipeline imports originate from Russia.

Turkey

Special focus should be given to Turkey's natural gas sector. Energy demand in Turkey has been growing by 5 - 8% annually, which is one of the highest rates in the world. In addition, natural gas consumption is the fastest growing primary energy source in Turkey. Due to the efforts to diversify energy supply, the consumption of imported natural gas has risen rapidly. According to the 2013 BP Statistical Energy Survey, Turkish natural gas consumption in 2010, one year after the global financial crisis, reached 39,0 bcm. In 2011 natural gas consumption showed a sharp increase at 45,7 bcm, while in 2012, there was a smaller increase reaching 45,9 bcm, which corresponds to 1,4% of the world total. In 2013 it was estimated at 46,6 bcm. Turkey is the biggest gas consumer, as well as among the most import-dependent countries in the region, because it covers almost all of its gas needs via imports.

Table 25. Turkey: Natural Gas Consumption 2010 – 2013.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)/9155 Kcal
2010	78,5	21,5	38,037
2011	85,2	14,8	43,874
2012	82,9	17,1	45,922
2013	87,8	12,2	46,600

Source: IENE

By 2013, more than 50% of Turkey's gas imports were supplied from Russia, mainly via the Blue Stream pipeline in the Black Sea (24,5 bcm), nearly 15% was supplied from Iran (7,5 bcm), about 6,5% from Azerbaijan (2,9 bcm), and the remainder from Algeria and Nigeria, in LNG form.

Table 26. Turkey: Natural Gas Consumption Forecast for 2014 – 2023.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2014	87	13	46,500
2015	86	14	49,541
2016	85	15	52,500
2017	84	16	55,200
2018	77	23	59,852
2019	78	22	57,779
2020	78	22	60,414
2021	79	21	61,103
2022	79	21	61,510
2023	79	21	60,971

Source: IENE

6.3. PLANNED MAJOR GAS PROJECTS OF SE EUROPE

In short, the infrastructure which is currently under development or planned and will be used to connect the supply sources to European markets, includes the following:

South Stream Pipeline

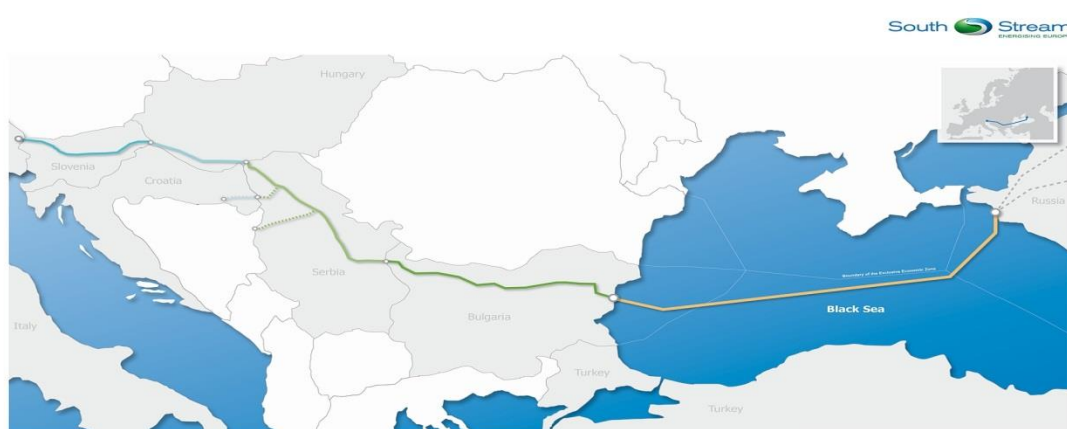
The South Stream gas pipeline system is clearly emerging as the most advanced project of all Southern Corridor pipelines. This is most evident judging from the advanced engineering design, the available gas supplies, and the secure funding. According to initial estimates, the total project implementation cost, including the infrastructure in Russia, will reach approximately 26,6 billion euros. The first of four subsea lines of the South Stream pipeline system will be completed by 2016 and the remainder are scheduled to come into operation at yearly intervals after that. The pipeline system will run under the Black Sea from Russia to Bulgaria and then north, through Serbia and Hungary towards northern Italy, on the Slovenian - Italian border (although there seems to be renewed talk of the line ending at Baumgarten in Austria). South Stream will be capable of carrying 63 bcm per year and its overall length is about 2.950 Km. In 2013, Gazprom estimated the total cost of South Stream at 29 billion euros, including 12,5 billion euros needed to boost capacity of its domestic pipeline system to deliver gas to its Black Sea coast.

Construction of the undersea section of the South Stream gas pipeline will begin early in the summer of 2014. South Stream Transport B.V., which is the pipeline's operator, will implement the offshore gas pipeline through the Black Sea. The contracts with the ports in

Varna and Burgas have already been signed and based on decisions already taken, project implementation will proceed according to the agreed schedule aiming at transporting the first gas quantities through the Black Sea by the first semester of 2016. The length of the offshore pipeline will be 925 kilometres with a designed capacity to transport 63 bcm of natural gas per year through four parallel strings.

South Stream Transport is an international consortium consisting of four major energy companies: OAO Gazprom (Russia), Eni S.p.A. (Italy), EDF (France) and Wintershall Holding GmbH (BASF Group) (Germany). In October 2013 Gazprom started building the Bulgarian section of the South Stream pipeline and in November of the same year construction begun on the Serbian section.

Picture 31. The South Stream Pipeline Project.



Trans Anatolian Gas Pipeline (TANAP)

The Trans Anadolu Gas Pipeline (TANAP) is a joint Azeri – Turkish project and aims to bring gas from Azerbaijan to the European edge of Turkey, and will be connected with TAP pipeline. The TANAP project envisages the construction of a pipeline from the eastern border of Turkey to the country's western border to supply gas from the Shah Deniz gas-condensate field in the Caspian Sea. Ongoing preparations to build TANAP, are to be completed by 2019 and will cost roughly \$10 billion.

In December 2011, Azerbaijan and Turkey signed a memorandum on mutual understanding to create the consortium to build TANAP. In June 2012 the intergovernmental agreement on TANAP was concluded. The pipeline, about 2.000 km long, is planned to be laid from the Georgian-Turkish Border and up to the Turkish–Greek Border (The pipeline which will transfer the gas from Azerbaijan to Turkish border across Georgia is the South Caucasus Pipeline, which is being expanded and has a different ownership structure to TANAP). At the first stage, the carrying capacity of TANAP will be 16 bcm of gas per year, 212 bcf (6 bcm) of which will be consumed by the Turkish consumers and 353 bcf (10 Bcm) will be delivered to European countries via TAP. At a second stage, it is planned to increase deliveries up to 847

bcf (24 bcm). The gas pipeline is planned to be put into operation in 2019 and will be devoted from the beginning to gas produced from the Shah-Deniz Phase-2 field.

Trans Adriatic Pipeline (TAP)

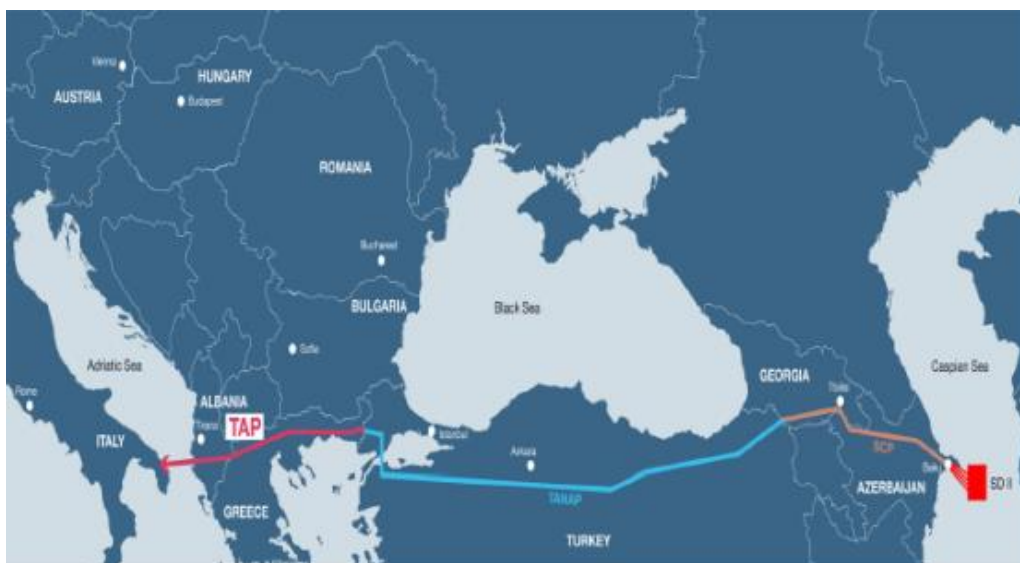
TAP has been selected by the Shah Deniz consortium, instead of the northern route (Nabucco West) to carry gas into Europe from Turkey's western border. The Trans Adriatic Pipeline (TAP) will connect existing and planned grids for natural gas transport in Southeast Europe with gas systems in Western Europe via Greece, Albania, the Adriatic Sea and Italy. The pipeline will therefore give Europe better access to the major reserves of natural gas located mainly in the Caspian region. The pipeline is designed with an initial 10 bcm/yr transport capacity and will be 48 – inches in diameter. It will have a combined length of 682 km onshore and 105 km offshore. It is estimated that the construction of the pipeline will cost about 5,3 billion dollars. In February 13, 2013, the governments of Greece, Italy and Albania confirmed their full support and commitment to the Trans Adriatic Pipeline (TAP) project by signing in Athens a tri-lateral intergovernmental agreement (IGA).

The natural gas reverse flow feature of TAP is an EU requirement set out in Regulation (EU) No. 994/2010 concerning measures to safeguard security of gas supply. It will also enable the region to connect to new gas sources, such as those in Northern Africa as well as to other more diverse sources, such as the partially liquid gas market in Italy. TAP is the only gas project, after the exclusion of ITGI by the Shah Deniz II consortium and the Russian refusal, to supply Greece and Albania with gas quantities via a southern branch of South Stream, destined to bring new gas supplies to the region. In a second stage there are plans for pipeline extension to West Balkan countries (Montenegro, Bosnia and Croatia) via the IAP pipeline. TAP as a Project of Common Interest has the support of European Union.

On May 17, 2013, the relevant regulatory authorities in Italy, Greece and Albania, the European Commission formally approved the Trans Adriatic Pipeline's (TAP) application for Third Party Access (TPA) exemption for the initial capacity of 10bcm/yr. The decision means that TAP can offer capacity for export of gas volumes from Azerbaijan to Europe for a period of 25 years. In addition, the Commission has approved exemptions from regulated tariffs on both TAP's initial and expansion capacity, as well as exemption from ownership unbundling for 25 years. Therefore, it must be noted that there is no exception for TAP's reverse flow capacity from Italy to Greece.

European Union internal market regulations typically require third party access to all energy infrastructure, including gas pipelines. However, national regulators can grant exemptions to this rule for a limited period of time, in order to facilitate major infrastructure projects such as international pipelines. Provided that all conditions have been met, the European Union then corroborates the decision, offering an exemption from certain provisions in the regulatory framework.

Picture 32. The TANAP – TAP Pipeline System.



IAP Pipeline

IAP is a planned natural gas pipeline in the Western Balkans. It will run from Fier, in Albania, through Montenegro and Bosnia and Herzegovina to Split in Croatia. In Fier, IAP will be connected with the planned Trans Adriatic Pipeline. IAP is considered to be a part of the TANAP-TAP–IAP pipeline system. Trans Adriatic Pipeline AG has signed various MoUs with developers of the IAP project, including Plinacro (Croatia), BH-Gas (Bosnia and Herzegovina), and governments of Montenegro and Albania.

Picture 33. The TAP - IAP Pipeline System.



In Split, the pipeline will be connected with the existing gas transmission system of Croatia. In addition, it may be connected with other new gas infrastructure, including the proposed Adria LNG terminal in Krk. The length of the pipeline will be 516 km (321 mi). The IAP will have a reverse flow capacity, and its capacity would be 5 billion cubic metres (180 bcf) of natural gas per year. The ministerial declaration on the IAP project was signed on 25 September 2007 in the framework of the Energy Community. The West Balkan countries prefer the construction of the Ionian Adriatic Pipeline (IAP) to start in lockstep with that of the Trans Adriatic Pipeline (TAP) in 2016 and natural gas is estimated to start flowing through IAP in 2020.

East Med Pipeline

The broad concept developed by Greece's Public Gas Corporation DEPA is for a new gas corridor in the East Mediterranean based on an underwater gas pipeline connecting Israel/Cyprus to Greece. Although several scenarios have been considered by DEPA to carry East Med gas to Europe, the pipeline scenario appears more advanced in terms of analysis, design work and financial engineering. The pipeline project considered by DEPA comprises (i) a pipeline from the offshore fields to Cyprus, (ii) a pipeline connecting Cyprus to Crete and (iii) a pipeline from Crete to Peloponnese and (or) through the Aegean Sea to Northern Greece, where the pipeline will be connected with the IGB interconnector.

Picture 34. The East Med Pipeline Project.



According to a recent DEPA study, the pipeline will be able to carry around 8 bcma. The initial design of the pipeline foresees a first leg of 150 km connecting the Cyprus/ Israeli gas fields to Cyprus, a second leg from Cyprus to Crete of 633 km and a third leg from Crete to mainland Greece of 405 km, i.e. a total of 1.188 km. There are two further options for the third leg. The first one foresees that the pipeline from Crete lands in the South Peloponnese

whence a 460 km onshore pipeline will connect it to the IGI Poseidon starting point at Thesprotia in Western Greece. The second option, which is less developed from a design point of view, will run beneath the Aegean Sea, connecting the east part of Crete to Komotini in Northern Greece (from where the IGB will start), i.e., a total distance of approximately 700 km. After a pre-feasibility study carried out by J P Kenny (Wood Group Kenny), DEPA has recently launched an international tender for a Feasibility Study with the first option as the main pipeline route (an offshore pipeline from Crete to south Peloponnese).

The East Med pipeline is expected to operate in tandem with the ITGI system which comprises the Interconnector Greece-Italy (IGI) and Interconnector Greece-Bulgaria (IGB) and thereby constitutes a powerful combination which can provide for the needs of the whole SE Europe. IGI is considered as one of the most technically mature projects of the region, while the construction of IGB will provide up to 5 bcma of either LNG or pipeline gas to SE Europe. The expansion of the existing LNG terminal in Revithoussa, already underway, in conjunction with two planned FSRU terminals, the first in Alexandroupolis and the other one in Kavala, are expected to feed the IGB. Therefore, the proposed East Med pipeline will create strong synergies with the ITGI system and will, in effect, connect the Eastern Mediterranean to the European grid. In case of an emergency, reverse flow would allow gas from Russia, Italy or even North Africa to reach the East Mediterranean countries.

Floating Storage and Regasification Units (FSRU)

The developments in the South Eastern European natural gas market are mainly characterized by a) the prospective introduction of Azeri gas into the market by 2019 through the Trans-Adriatic Pipeline (TAP), b) the South Stream pipeline, which initially will substitute the gas quantities that currently pass through Ukraine, but afterwards will also supply the region with new Russian gas supplies, c) the gas interconnectors and d) the new LNG terminals. For that reason, countries such as Greece are eyeing opportunities to exploit the new emerging gas mix that will also be coupled with substantial amounts of Russian gas through the South Stream pipeline, as well as through independent LNG suppliers as a result of the liberalization of the regional markets.

Picture 35. Alexandroupolis LNG INGS – A new energy gateway to Europe.

More specifically on the LNG sector, apart from projects aiming at either enhancing the existing infrastructure or establishing new terminals, there are two noteworthy plans in Greece, regarding the construction of Floating Storage and Regasification Units (FSRU). They are to be located right beside the route of the TAP project and the Greek–Bulgarian interconnector IGB and the existing Greek–Turkey (IGT) nearby the Bulgarian and Turkish markets, in order to be able to link themselves through the planned interconnectors.

Firstly, the private Greek company GASTRADE, who received an Independent Natural Gas System license in 2011, is developing a 6,1 bcm annual capacity floating LNG storage and regasification unit offshore Alexandroupolis. The project has been submitted to the Greek energy regulator in 2010 and has received environmental assessment approval in 2013. The 170.000 m³ offshore storage facility will be linked to the Greek National Natural Gas System through a 28 km subsea and onshore pipeline. The project location is in proximity with the TAP route and is around 55 km from the entry point of the planned interconnector Greece–Bulgaria (IGB). Completion of the permitting process is expected within the third quarter of 2014, whilst commercial operation start up can be seen as early as 2016. The Alexandroupolis LNG Terminal has been included in the first list of the EC Projects of Common Interest (PCIs). The budget of this project is estimated at €340 million and will be able to accommodate imports from various LNG sources through long-term and spot purchases, including gas from the Eastern Mediterranean fields when it becomes commercially available, adding thus to the liquidity of the local and regional markets.

Concurrently, the Greek DEPA Company is also laying down its own plans concerning a separate FSRU unit, a 3 bcm per annum facility near the port of Kavala and in a strategic location close to the aforementioned pipeline and interconnector. The project aims for a 150.000 cubic meters storage capacity and DEPA already actively seeks international investor backing for this 400 million-dollar plan. The medium-term business plan of DEPA calls for an increase in the capacity of the Kavala FSRU to 5 bcm. Success depends mostly on

DEPA's ability to attract international investor interest, taking into account the state of affairs of the Greek economy nowadays that prohibits DEPA from raising such capital by itself. Moreover, the moves by neighbouring countries are crucial, since a series of similar projects involving FSRU and underground storage cannot proceed all together, due to limitations of market dynamics and the rather low potential of the regional markets, as compared to the rest of the EU.

6.4. GAS INTERCONNECTIONS IN SE EUROPE

In February 2011, the European Council decided that each EU member state should have at least two sources of gas and electricity by 2014 to avoid repeating the scenario some member nations encountered following the Russian-Ukrainian gas crisis in January 2009.

The dispute left many countries of the region, such as Bulgaria, without gas for three weeks. It should be noted that during the crisis between Russia and Ukraine, the Revithoussa LNG terminal in Greece not only fully covered domestic needs in natural gas, making Greece the only European country supplied from Russia not facing any problems in covering its consumption, but also allowed the natural gas supply of Bulgaria for two days.

As a result, Greece, Bulgaria, Romania and Serbia commenced construction of gas infrastructures and especially gas interconnections, in order to avoid future gas disruptions and increase their energy security. This network of gas interconnectors will supply the region with new natural gas quantities coming from the TAP pipeline, the liquefied natural gas terminal in Revithoussa (currently the only LNG terminal in Greece) and possibly from one of the planned floating LNG terminals (FSRU) in Northern Greece.

Picture 36. Gas interconnections in SE Europe.



The Interconnector Bulgaria and Romania (IBR)

Bulgaria commenced construction of a gas interconnection with Romania, on August 2011. Total project value is approximately €24 million, €9 million of which are EU funds, €11 million are from Bulgaria, and the rest is to be provided by the Romanian Transgaz. The total length of the pipeline between Giurgiu and Ruse is 25 km with 15,4km in Bulgaria and 2,1 km beneath the Danube. Following a number of technical delays, the Bulgaria-Romania gas grid interconnection was expected to start functioning in June 2014.

Bulgaria, through the above interconnector, could import gas from Romania which has an advantage over Bulgaria in terms of natural gas deposits in the Black Sea. The pipeline between Giurgiu and Ruse will have an annual capacity of between 0,5 and 1,5 bcm of natural gas, representing half of Bulgaria's consumption. The initial capacity of the interconnector will be at 0,5 bcm.

Interconnection between Bulgaria and Romania is a project highly supported by Romania as well. It is particularly important because it can provide short-term flow of gas in a moment of crisis due to its reverse flow capacity, and in the long term, contribute to security of supply of both countries.

The gas interconnection pipeline between Bulgaria and Romania is not the only project that Bulgaria is counting on in order to reduce its energy dependence from Russian gas, allowing it to avoid gas supply crises, such as it experienced in the winter of 2009. Bulgaria will also build a connection with the Greek natural gas transmission system through the IGB, while the Bulgarian Ministry of Economy is working closely with the Turkish Ministry of Energy and Natural Resources on the Bulgarian-Turkish gas interconnection.

Bulgarian-Turkish gas interconnection (ITB)

The project is likely to receive a grant from the European Union. The interconnector project with Turkey is described as being "key" to Bulgaria's energy diversification efforts in view of the fact that the Turkish system has six entry points for natural gas. The 77km-long gas pipeline (75 km on Bulgarian territory and 2 km on Turkish territory) will carry up to 3 bcm metres of Caspian natural gas a year initially, the pipe diameter is 28 inches (700 mm) and the working pressure 75 bar.

The ITB project will provide a supply point not only of Azerbaijan gas, but also for traders using future gas liquefaction terminals to liquefy gas in Turkey. On March 20, 2012, Bulgaria and Turkey signed a declaration to accelerate the construction of the gas interconnection between the two countries. The implementation of this project will provide conditions necessary for the diversification of sources and routes for Bulgaria. However, the project is still at an initial planning – conceptual stage.

Bulgarian-Serbian gas Interconnection (IBS)

Interconnection Sofia-Dimitrovgrad (Serbia)-Nis (Serbia), will connect national transmission networks of Bulgaria and Serbia. The aim is to ensure diversification of routes, intersystem connectivity and gas transmission. It is expected that construction of the pipeline will provide an option for delivery of up to 1,8 bcm/yr of natural gas, in both directions, with the opportunity to further increase the volumes up to 4,5 bcm/yr. The total length of the route is 150 km, of which around 50 km are on Bulgarian territory. Possible pipe diameter is 28" and the working pressure is 55 bar.

On 8 April, 2011, a Memorandum of Understanding between the Government of the Republic of Bulgaria and the Republic of Serbia was signed in order to create favourable conditions for connecting the transmission systems of both countries and on 15 April 2011, a contract was signed between the Ministry of Economy, Energy and Tourism and the Ministry of Regional Development and Public Works, for the implementation of a project "Preparation, studies and design for construction of a Gas Interconnection Bulgaria-Serbia".

Anticipated benefits from project realization:

- Development of cross-border cooperation between Bulgaria and Serbia. Implementation of a direct connection for the gas markets of the four member states - Bulgaria, Romania, Greece and Hungary - to the gas markets of the other SEE countries;
- Diversification of sources of natural gas to Bulgaria and the markets for importers, increasing access to alternative suppliers and decreasing their dependence on one source;
- Greater flexibility for the operator in balancing the transmission system in the country and the region, and wider access to regional underground gas storages and opportunities to further increase natural gas consumption;
- Create jobs and support further economic recovery.

Through interconnections with neighbours in gas transport, Bulgaria proves to be the initiator of many projects of this type, making use of EU grants. The European Commission has already approved €9 million in financing for the Bulgaria-Romania gas interconnection and €45 million for the Bulgaria-Greece gas interconnection, as well as another €2,5 million for a feasibility study for the Bulgaria – Serbia Interconnector. The interconnector will start functioning not earlier than 2018.

Greece Bulgaria Gas Interconnector (IGB)

The IGB, which will supply Bulgaria and hence, South Eastern Europe region, with up to 5 bcma, will be operational by 2015. The project includes the construction of a trans-border reverse flow gas pipeline with a length of about 168,5 km (140 km in Bulgaria, 28,5 km in Greece), connecting the Greek gas network in the area of Komotini with the Bulgarian gas network in the area of Stara Zagora. The capacity of the gas pipeline is foreseen to be 3 up to 5 billion m³/yr, with a pipe diameter of 750 mm (32").

The total indicative value of this project is €200 million. Funding is secured from the European Energy Recovery Programme and the amount of €45 million has already been earmarked (Decision C (2010) 5813 of the European Commission on 30.08.2010).

The construction of the Greece-Bulgaria Interconnection Pipeline will help Bulgaria to achieve real diversification of natural gas supply sources, as it will allow the delivery of additional natural gas through the Southern Gas Corridor. This interconnector will also help Bulgaria access LNG gas from Greece, by allowing direct purchases from suppliers. In addition, the IGB will help develop a more liquid market in the region.

Gas from the above interconnector may originate from:

- (a) the 1st phase of Shah Deniz.
- (b) LNG terminals, either the existing one in Revithoussa or the planned FSRUs in Northern Greece (Alexandroupolis, Kavala)
- (c) Should, by 2020, TAP pipeline between Greece and Italy be operational, it will be possible to access Algerian gas through Italy (via reverse flow).

Interconnector Greece-Italy (IGI Poseidon)

IGI Poseidon, the 50/50 Joint Venture between Edison and Greece's DEPA, submitted a technical and commercial proposal to transit gas from the Shah Deniz II field in Azerbaijan to Europe through ITGI transit corridor (Interconnector Turkey-Greece-Italy). IGI Poseidon is the company responsible for the development and construction of the new pipeline between Greece and Italy, which will be part of the transit corridor ITGI (Interconnector Turkey-Greece-Italy).

ITGI project will use existing infrastructures in Turkey and Greece, with a new pipeline to be built connecting Greece to Italy (IGI pipeline). IGI pipeline has a transport capacity of up to 12 bcm a year and comprises two sections:

- *IGI Onshore*: 600 km onshore pipeline in the Greek territory (to be developed by Desfa, the Greek Transmission System Operator)
- *IGI Poseidon*: 200 km offshore pipeline across the Ionian Sea (under development by IGI Poseidon SA, a joint venture between Edison and the Greek company DEPA).

The shareholders of IGI (DEPA and Edison) have decided to continue the development of IGI Poseidon, based on the maturity of the project and the strong belief that it is a crucial project for the security of supply of the entire region, even though this project was not selected by the Shah Deniz consortium. It should be noted that IGI Poseidon remains open to export natural gas from alternative sources. The EU acknowledged IGI as a Project of European Interest and included it among its Projects of Common Interest (PCI).

Gas Interconnectors in Romania

Hungarian link

Apart from the interconnector between Romania and Bulgaria (IBR) another key interconnector project is the creation of two-way flows on the Arad-Szeged pipeline from Romania to Hungary, which is currently only capable of importing gas into Romania. Transgaz is looking to complete the project by December 2016, with the condition that it can secure agreement with relevant Hungarian authorities.

This could pave the way for gas transport from the Black Sea into markets in Central and Eastern Europe, as well as Western Europe via Austria. The Romanian TSO stated that the regional significance of the plan means it could be adopted on the EU list of projects of common interest by the end of 2014 and would, therefore, be eligible for EU funding.

Serbian link

Transgaz is developing plans to construct an interconnector with Serbia, which would allow Romania to gain access to the South Stream pipeline. This project could also potentially offer access to LNG imports via the proposed regasification terminal in Croatia. The Serbia interconnector is still in the early stages and the Romanian TSO is now looking to contact relevant authorities on the Serbian side to gauge the appetite for such a pipeline.

Table 27. Estimation on when the reverse flow capacity will become available.

Main Pipelines and Interconnector Pipelines	Year
Greek – Bulgarian (Sidirokastro)	2014 (2nd half)
Bulgarian - Turkey	2017
TAP	2018
Greek – Turkey (ITG)	Date has not been finalized
IGB	2017
ITB	2016
IBR	2014

Source: IENE

6.5. AVAILABLE AND PLANNED STORAGE CAPACITY

Greece's Gas Storage Projects

South Kavala Offshore Natural 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 planned TAP pipeline. Energean Oil & Gas has submitted to the Regulatory Authority of Energy a study about the process of converting the almost depleted South Kavala Gas field into an Underground Gas Storage Facility utilizing the existing infrastructure. South Kavala is an offshore gas field with an initial volume of 1 bcm at a

depth of 52 m and 30 km from the coast. The conversion into an underground natural gas storage facility will require an investment of approximately 400 million euros.

The working gas storage capacity ranges from 360 to 530 mcm, the total volume - from 720 up to 1 billion, a daily rate of withdrawal - from 4 to 9 mcm, a daily rate of injection - from 5 to 7,5 mcm. The existing marine and coastal infrastructure (a set of offshore platforms and installations for processing gas for further transportation), and close proximity to the national gas transmission network, are also in favour of the conversion project.

The Underground Gas Storage Facility of 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 Kavala Gas Storage is ideally positioned to support major gas pipelines and interconnectors (TAP, IGB, IGI) or act as an entry point for new offshore gas projects in the East Med region.

The project has been adopted by European Commission as a Project of Common Interest under Regulation (EU) No 347/2013 on Guidelines for trans-European energy infrastructure. Detailed information of the planned underground gas storage facility in South Kavala is given in Appendix.

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 2007, an expansion project was completed to upgrade the terminal, increasing its capacity to 185 bcf/y (5,2-5,3 bcm annually). The LNG is stored in two in-ground tanks, with a total capacity of 130.000 m³.

Revithoussa terminal is to expand its cryogenic facilities, which will boost the gas send-out rate to 1.400 m³ per hour. Currently, the terminal handles 0,68 bcm of gas per year, and consists of an import jetty, two full containment storage tanks, plus one under construction, re-gasification equipment and send-out facilities.

Bulgarian Gas Storage Projects

Chiren Underground Storage Facility

In Bulgaria natural gas is being stored in the Chiren underground storage facility, owned by "Bulgartransgaz" EAD. The storage has been constructed on the basis of an already exhausted gas field in the area. The storage facility is used to compensate for the seasonal irregularities of natural gas consumption in the country, as well as to ensure the security of gas supplies in Bulgaria. The storage has a capacity of 1,35 bcm of natural gas. The available production capacity is 0,6 bcm, while the other 0,75 bcm are used to keep the facility operational. Bulgaria's only natural gas storage facility in Chiren will be expanded to reach

its maximum usable capacity of 1 bcm of natural gas. The expansion of the Chiren site – which should be completed by 2015, will cost the company about 200 million euros.

Galata offshore Gas Storage

The gas field located off the Black Sea coast about 20km from the eastern port of Varna is operated by Scottish-based oil and gas company Melrose Resources. It ceased production at the field on 31 January 2009 in order to start preparations for converting the field into a gas storage facility. The field lies at a water depth of 35m and had gross proved and recoverable reserves of 1,37 bcm, and proved and probable reserves of 2,26 bcm. About 0,2 bcm of gas reserves were left at the field when production ceased.

Melrose had talks with the Bulgarian Government in order to get approval to complete the Karvarna field development as a subsea tie back and for the gas injection at the Galata gas storage project. The company also plans to speed up the activities related to completing the agreements required for the commencement of the Galata gas storage project. Karvarna and Kaliakra are two other fields being developed within the Galata project. First gas production from the two fields began in November 2010 after receiving government approvals in November 2009.

A memorandum of understanding was signed between Melrose and the state-owned gas utility Bulgargaz at the end of 2007. As per the agreement, the company and Bulgargaz conducted an assessment of the feasibility of converting the gas field into a storage facility.

The project was found feasible and further plans were drawn up for a three phase conversion of the field. A capital expenditure of \$90m was committed for developing the storage facility with a capacity of 1,8 bcm. The first phase of development of the gas storage facility started in 2009 and involved field compression. The second and third phases will involve tying-back Galata second well and installation of metering facilities respectively. The first phase required an investment of \$30m. Phase I will provide storage capacity of 0,7bcm. Phases II and III, with an investment of \$30m each, will raise the capacity to 1,2bcm and 1,8bcm, respectively.

Romanian Gas Storage Projects

Romania has eight underground storage facilities with a combined capacity of 3 bcm (106 bcf). Of the eight, six are operated by Romgaz and two are operated by Depomureş and Amgaz. The Romgaz underground storage facilities have a combined capacity of 2,76 bcm. The storage facilities are located in Sărmăşel and Cetatea de Baltă in Transylvania and in Bilciureşti, Bălăceanca, Urziceni and Gherceşti in Southern Romania. The largest of the six storages is the Bilciureti facility located 40 km North-West of Bucharest having a storage capacity of 1,3 bcm in one cycle and it is located at a depth of 2.000 m.

A joint venture between Romanian gas producer Romgaz and Gazprom for the construction of the Roman-Margineni gas storage facility was established in 2009. However, a project

feasibility study indicated that such a storage facility should not be built before the implementation of the gas supply diversification projects that are planned in Romania.

Albanian Gas Storage Projects

The need for more storage in South East 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 frame the Albanian government is planning the development of natural underground gas storage (UGS) reservoirs located in the Southwest part of the country where many depleted oil fields exist. There are two possible locations for the construction of a UGS: the depleted gas field near Divjaka and the salt formation in Dumre, in Central Albania. Although feasibility studies have been carried out on both locations, their economic attractiveness is questionable. The project of Divjaka envisages a large number of wells, which means high maintenance costs. Moreover, the lower pressure in the storage could require additional measures, which will probably increase the value of construction works by 50%.

The scenarios for the Dumre gas storage depend on its function. If Dumre is developed as storage to cover only national needs, two caverns of 55-60 m diameter will be leached, each storing some 65-75 mcm of natural gas. Such a decision, however, will diminish the quantities as well as the chances of investment in salt production. The shaping of the two caverns will take four years. In the second scenario, Dumre will meet the need of the regional and the transit gas markets. The project includes the leaching of eight caverns with 70-80 m diameter, which will have a combined storage of up to 1,2 bcm of gas. It is very likely for the project to attract a salt production company to develop the mine and reduce the operation costs of the storage. Taking away the salt and leaching four caverns will take about eight years.

Serbian Gas Storage Projects

In 2010, Serbia launched its first natural gas underground storage facility in the northern town of Banatski Dvor. The Serbian storage facility is to be part of the South Stream project and it is one of the largest underground gas storage (UGS) facilities in South Eastern Europe. Its working gas volume makes up 450 mcm, maximum deliverability – 5 mcm per day. In addition, Banatski Dvor has a potential for further expansion. The UGS facility enhances the security of Russian gas export to Hungary, Serbia, Bosnia and Herzegovina.

7. KEY MARKET PLAYERS AND THEIR ROLE IN A REGIONAL GAS HUB

As shown in Chapter 6, several natural gas infrastructure projects in South Eastern European countries 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 Revithoussa LNG terminal close to Athens, which mainly imports from Algerian Sonatrach and aims to be able to have a throughput capacity of more than 2 bcm per year over the coming years. Concurrently, Turkey operates two terminals, one in the Marmara Sea, close to Istanbul, and another in Izmir, supplied by a variety of companies from Nigeria, Equatorial Guinea and Qatar. The construction of at least one FSRU station in North Greece will facilitate the access of South Eastern Europe to more LNG quantities in addition to the LNG terminal in Revithoussa.

Overall, these plans can work in conjunction with the IGB, which should be operational by late 2016, 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 South Eastern Europe's system by 2018 - 2023 and the case for gas price competition will become much stronger. On the other hand, for the 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.

7.1. TRADITIONAL AND NEW GAS SUPPLIERS AND THEIR ROLE IN THE OPERATION OF A GAS HUB

Russia

Russia accounts for 34% of EU natural gas imports, making it the lead supplier of natural gas to the EU and particularly to South Eastern 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. The annual export volumes from Russia to South Eastern Europe (Turkey, Greece, Bulgaria, Romania and Croatia) exceeds 35,5 bcm of gas and could potentially reach 50 bcm following the launching of South Stream and the implementation of other gas infrastructures such as underground gas storages and gas interconnectors.

The Ukraine crisis has led to a debate concerning the implications for European gas markets and how to deal with possible threats to gas supplies, both in the short and long term. There is no question that Europe will remain dependent to a large extent on Russian gas imports. This implies that the EU should support Gazprom's efforts to diversify away from Ukraine, in particular through the Nord Stream and South Stream pipelines. The current conflict with Ukraine strengthens the rationale for the South Stream pipeline, which would bring Russian gas across the Black Sea to Bulgaria.

Gazprom might not be able to book and utilise full capacity in the onshore extensions of both Nord Stream and South Stream, as the EU Third Package for gas requires inter alia Third Party Access unless an exemption is granted. Some arguments support the view that in light of the Ukraine crisis, the EU should allow Gazprom to use Nord Stream and in the future the new South Stream pipeline for itself, without a requirement to grant access to third parties. Nevertheless, others suggest that the EU should adopt a strict regulatory policy towards South Stream and subject all of Gazprom's activities to intense legal scrutiny.

The European Commission announced in March 2014 that it wants to further investigate this project before making a decision. Furthermore, Energy Commissioner Günther Oettinger stated that the EU would "delay" a decision on South Stream in response to Russian actions in Ukraine.

Securing TPA for the South Stream pipeline project is critical, as it will allow the countries of the region, especially Bulgaria, Serbia, Hungary and Slovenia, to improve their capacity utilization and trade some marginal gas quantities. The TPA would force Gazprom to allow third-party gas suppliers, such as Greece or the Shah Deniz project partners, to also use the European section of South Stream pipeline. This is very important because trading hubs are created only when there is a TPA regime and this has reached a certain level of maturity. In

a trading hub, shippers can freely trade their excess capacities, thereby improving the liquidity of pipeline capacity in the region.

On April 4, 2014, Bulgaria's parliament legislated for the Bulgarian section of South Stream to be redefined as a "gas grid interconnection" rather than a pipeline, which theoretically allows the project to circumvent EU competition legislation. The idea is that the new legal definition of South Stream as a connector that is an extension of an existing network will mean that Gazprom will not have to open the crucial Bulgarian part of the pipeline to third parties under the EU's Third Energy Package. The widespread assumption is that Gazprom would be less keen on the project were it forced to open up its infrastructure to other suppliers.

North Africa

In North Africa, some countries like Algeria, Libya and Egypt have the potential to become some of the largest European suppliers. The three countries together could provide about 44 percent of what Russia does today, according to the U.S. Energy Information Administration. However, problems with infrastructure and political instability are getting in the way.

Currently, Algeria ranks as the fourth-largest supplier of natural gas to the European Union, exporting some 47 bcm/yr primarily to Spain, Italy, France and the United Kingdom. Currently Algeria supplies about 30% of Italian and 20% of Spanish gas demand. It is also interesting to note that 45% of the Algerian volumes arrive in Europe as LNG, rather than by pipeline. The country's export infrastructure is highly developed and features two sub-Mediterranean pipelines and three LNG facilities, each with spare capacity. Moreover, Algeria has been willing to commit to long-term supply contracts, which are preferred by several European countries that typically favour locking in advantageous prices and terms, for long periods of time. In case of an emergency, Algeria could play a crucial role in feeding the Balkan countries with gas, as the TAP's reverse flow capability would allow gas from North Africa to reach the South Eastern European region through Italy.

Algeria's regional neighbor Egypt has seen domestic for natural gas increase more than 57 percent since 2005, but production is limited, partly because of hard-to-reach reserves. While potentially a rich new source of supply for Europe, attacks from Bedouin and terrorist groups in the Sinai Peninsula have halted Egyptian exports much closer to home in Israel and Jordan. Egypt will need to make the tough political decisions to cut fuel subsidies and encourage western investment before it can tackle an ambitious export plan. Several sources from the market say that even under the most optimistic scenario, the Egyptians will be unable to overcome its gas shortage before the 2020s.

On the other hand, in Libya, natural gas production dropped 90 percent during the 2011 civil war. The industry has recovered to a degree but civil unrest, protests and strikes still hamper production. Still, Libya holds the fourth-largest amount of natural gas reserves in Africa, and new leadership could help facilitate further exports.

Iran

Holding the world's largest reserves of natural gas, Iran was expected to become a large-scale exporter for many decades. However, Iran is in reality a net-importer of natural gas. Imports of 9,4 bcm exceeded the country's total exports of 8,4 bcm in 2012, according to the BP statistical review (2013). The only larger export project, with Turkey at 7,5 bcm/yr, is running far from smooth while trade with Armenia and Azerbaijan is marginal. Furthermore, sanctions imposed by USA and West leaders are obviously responsible for Iran's isolation and the lack of investments from west companies. Before sanctions, Iran enjoyed access to international banking with European companies like ENI or Total actively engaged in Iranian gas projects.

Assuming a solution is found to the nuclear issue and sanctions are lifted, Iran will have the chance to export gas to Europe, Persian Gulf states and Iraq. Recently, Iran announced that the completion of the three gas trunk-lines IGAT-6, IGAT-7 and IGAT-9 will facilitate gas exports to Iraq, Europe and Persian Gulf. Therefore, Iran and Iraq have signed an agreement for the construction of a pipeline that will carry Iranian natural gas to feed power plants in the Southern Iraqi province of Basra. The 56-inch pipeline originating from Assaluyeh, near the massive offshore South Pars Gas Field in Southern Iran, will continue into Iraq to feed three Iraqi power plants consuming gas.

The pipeline will be designed in such a way that it will be able to deliver gas to other Muslim countries like Jordan, Syria and Lebanon in the future. Iran is making efforts to raise its gas output by more foreign and domestic investments, especially in the Southern Pars gas field. Laying a pipeline to carry Iranian gas to Iraq has been worked out and negotiations with the Iraqi officials to initiate export of Iranian gas to Iraq were under way. The deal for gas export to Iraq finalized in early May 2014. However, the implementation of the project came to an halt due to lack of security in Syria and the recent Iraqi crisis. Iranian officials stated that if the situation in Syria and Iraq comes to normal, the project will be implemented.

Azerbaijan

Azerbaijan is capable of playing two key roles in helping ensure stable gas supplies to Europe: as a producer with its own gas sources and as a prospective entry point for the supplies from the Eastern shores of the Caspian Sea (Turkmenistan, Kazakhstan). Nevertheless, Azerbaijan is unlikely to play a transit role before it has secured markets for its own gas, not just from Shah Deniz, but also from a number of other prospective developments, including Absheron (being developed by Total of France), Umid (being developed by Socar, with possible future foreign participation) and a number of other prospects. Therefore, until markets are secured for this gas, Azerbaijan has little incentive to provide a transit route for competing supplies from Turkmenistan. It is now generally agreed that Shah Deniz contains around 0,9 tcm of recoverable gas reserves. For Azerbaijan, establishing a direct connection between Turkey and Italy through the implementation of the TAP project is likely to prove the key element for increasing its gas exports to the European market. At present, Azerbaijan is already shipping around 8 bcm/yr westward, most of which is directed to Turkey, while a small part is re-exported (up to 0,75 bcm/year)

to Greece. In the immediate future, the focus is on the second phase of development of Azerbaijan's giant Shah Deniz field, which will bring 16 bcm of new gas that will be delivered through the TANAP – TAP system. Once that connection is made, the Southern Corridor can be expected to grow organically – and that will result in gas flowing in ever greater volumes from the Caspian to all parts of Europe – not just to Italy, but via Greece and Albania to the rest of SE Europe.

Cyprus & Israel

Almost one tcm of recoverable natural gas has been discovered in Israeli and Cypriot waters, comparable to the proven reserves of Azerbaijan's Shah Deniz field, enough to cover a small part of European demand over several years. Although export projects are at early stages and politically difficult to implement due to the region's instability, increased efforts are being made to make some of this gas available to Europe. Through Cyprus, the EU would gain a new internal supply source. These new sources of gas will help enhance supply diversification in the European market. The East Mediterranean gas quantities will involve supplies from Israeli and Cyprus fields and in a second phase, potentially from Lebanon and Syria, beyond 2030. Gas deliveries could be at first in the form of LNG supplies and then delivered by pipeline (e.g. the East Med pipeline). For Cyprus the construction of an onshore LNG terminal in the Vassilikos coastal side continues to be a top priority project. In order for the LNG terminal to be commercially viable, more sufficient quantities of natural gas need to be found in Cypriot waters. On the other hand, Israel has expressed its intention to export to its immediate neighbours – Jordan, Egypt and the Palestinian Authority – and has entertained the possibility of using Egypt's unused LNG export terminals to process Israeli gas. More specifically, in May 2014, the Tamar natural gas field licensees announced the signing of a letter of intent to sell 4,5 bcm of gas per year to Spain's Union Fenosa SA, which operates Egypt's natural gas export facility at Damietta.

According to estimates, Israel and Cyprus could deliver to European markets after 2020 - 2022 an amount of 10 bcm per year. However, accessing East Mediterranean gas will be expensive. Total anticipated investments in East Med gas development, for both Israel and Cyprus, are likely to reach 60 billion euros by 2023. Building gas export facilities in the region will also be politically challenging.

7.2. TRANSIT COUNTRIES AND THEIR ROLE IN A GAS HUB

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 25,47 bcm of natural gas from Russia in 2012, according to Gazprom and Eastern Bloc Research. Turkey also received about 8,2 bcm of Iranian natural gas in 2012 via the Tabriz-Dogubayazit pipeline. An additional 3,30 bcm arrived from Azerbaijan via the Baku-Tbilisi-Erzurum (BTE) pipeline in 2012. The Turkish central pipeline network, controlled by BOTAŞ, distributed almost all of this natural gas to various consumers within the country.

Table 28. Additional gas supply potential in Turkey from various sources for 2015 – 2024.

YEAR	LNG (BCMA)	RUSSIAN	IRAQ	AZERİ	TURKMEN.	IRAN	EAST MED.	LOCAL
2015	5	1	-	-	-	-	-	-
2016	5	2	-	-	-	-	-	-
2017	5	2	2	-	-	-	-	-
2018	5	2	2	1	-	-	6	-
2019	15	2	3	4	-	-	6	-
2020	15	5	3	6	-	-	6	-
2021	15	5	3	6	-	-	6	-
2022	15	5	4	6	-	-	6	-
2023	15	5	5	6	3	6	6	2
2024	15	5	6	14	3	6	10	3

Source: IENE

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 natural gas demand is forecast to grow to 81 bcm/yr by 2030 from the current 47 bcm/yr. It could potentially trade up to 100 bcm/yr 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.

Table 29. Anticipated gas deliveries through spot trades in Turkey: Reference Scenario.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2018	0	10	6,0
2019	1,1	10,4	6,7
2020	1,5	9,9	6,9
2021	1,5	9,8	6,9
2022	1,5	8,1	5,9
2023	1,5	8,2	5,9

Source: IENE

Table 30. Anticipated gas deliveries through spot trades in Turkey: Optimistic Scenario.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2018	1,7	11,7	8
2019	1,7	12,1	8
2020	2,0	11,6	8,2
2021	2,4	11,4	8,5
2022	2,4	13,0	9,5
2023	2,5	13,1	9,5

Source: IENE

Greece

The Interconnection Turkey-Greece (ITG), which was inaugurated in November 2007, the Trans Adriatic Pipeline (TAP) and the planned Greek – Bulgaria Interconnector (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 upgrading of Revithoussa LNG terminal, in addition to the future implementation of at least one FSRU terminal in Northern Greece, 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 South Eastern 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 Floating Storage and Regasification Units, underground gas storage in the South Kavala basin, TAP or the ITGI system, it could then emerge as an important natural gas player in South Eastern 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, but the country has to define both its bilateral cooperation projects and how it will reconcile its Balkan-focused strategy with participation in wider-reaching energy projects. Bulgaria's position is important, since it will be the first European country through which the South Stream pipeline will pass. It was announced that the construction on the Bulgarian section of South Stream would start in June 2014, although early that month the European Commission asked the Bulgarian government to suspend work on the pipeline until a decision is reached on whether it conforms to EU law. In addition to the existing pipelines that already allow Bulgaria to import gas from Russia and the South Stream pipeline, which could deliver additional

volumes 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. Bulgaria has already agreed with Azerbaijan to import 1 bcm from TAP. The implementation of the reverse-flow gas link with Greece will achieve a true 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 at least one LNG FSRU stationed in North Greece, are extremely important for achieving a diversification of gas supplies for the countries in Southeast Europe, with Bulgaria playing a crucial role in the formation of an inter-regional trading hub.

Table 31. Anticipated gas deliveries through spot trades in Bulgaria: Reference Scenario.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2018	0	100	0,02
2019	5	95	0,03
2020	5	95	0,04
2021	5	95	0,06
2022	5	95	0,07
2023	10	90	0,09

Source: IENE

Table 32. Anticipated gas deliveries through spot trades in Bulgaria: Optimistic Scenario.

Years	From Pipelines (%)	From LNG (%)	Total (bcm)
2018	0	100	0,05
2019	2	98	0,08
2020	3	97	0,11
2021	4	96	0,16
2022	5	95	0,19
2023	10	90	0,23

Source: IENE

Albania

Albania needs to connect to the Southern Gas Corridor as a priority investment project in this sector, in order to enhance reliability and security of supplies and stimulate sustainable economic growth. TAP's selection was a development of vital importance to Albania, since the building of this pipeline will help the country diversify its energy mix at increase its security of energy supply. In Albania, TAP will most likely be the largest direct foreign investment in the country's history. TAP will put Albania on the natural gas map of South Eastern Europe as an important transit country; not only can Albania receive gas from TAP, it could also become a hub for the West Balkans through the development of the Ionian Adriatic Pipeline (IAP). Finally, there is potential to develop storage facilities near Dumre.

Developing the underground gas storage capacities in parallel with TAP, IAP and an LNG terminal is the main objective of Albania towards its gasification and gas interconnectivity in

the region. If Albania can become a hub for supplies mainly to the West Balkans region and possibly house a gas storage facility, it will have a major positive impact in the region.

Developing such strategic infrastructure will help establish an integrated gas market over South Eastern Europe. Nevertheless, the main challenge in Albania is that TAP is such a big cross-border project and legislation is not yet complete for every element of a venture of this magnitude. Unlike in Italy and in Greece, there is no precedent for developing natural gas pipeline projects. Although there is widespread support for TAP, adapting permitting, legal and fiscal terms is necessary in order to meet the overall project schedule and financing requirements.

Romania

Romania can play a dual role in ensuring new volumes of gas in the region. Upon the completion of gas interconnectors with Hungary, Serbia and Bulgaria, Romania will gain access to additional gas quantities from Austria (through Hungary), from South Stream (through Serbia) 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 construction of the Serbian section of the South Stream pipeline, which will stretch to about 280 miles, started near Belgrade in November 2013. Serbia is likely to become a key country through which the South Stream pipeline will pass, since it will branch out into neighbouring countries from Serbia (i.e. Croatia, Bosnia – Herzegovina, Kosovo). 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, Croatia, FYROM, Romania and Bulgaria.

Italy

Italy, Europe's third-biggest gas market after the UK and Germany, is emerging as Southern Europe's core gas trading point, as new pipelines and LNG projects make it one of the continent's most diversely supplied markets.

Yet, despite importing 68 bcm of gas from Russia, North Africa (Algeria and Libya) and the Netherlands, and with more than 40 bcm of extra import capacity planned for coming years, a lack of transparency has crippled trading activity. A virtual gas trading point, the PSV, was created in 2003, but a lack of liquidity and competition, together with pipeline bottlenecks, have kept Italian spot prices at a premium to those at other European trading points.

Government measures forcing Eni to spin off pipeline capacity have, however, boosted trading and prices have finally started to track spot prices on Northern European hubs.

As it was already pointed out in Chapter 2, Italian day-ahead gas prices trade above 27 euros (\$36,02) per megawatt hour (MWh), a premium of two euros to the Dutch TTF exchange, mainland Europe's most liquid gas. Yet, despite recent progress, gas trading liquidity in Italy still lags far behind other western European hubs.

TAP will now help Italy to become a truly Mediterranean hub. It is the missing link connecting Italy to enormous resources of gas in the Caspian, but it is also of great importance because it will link the enormous gas market of Italy with an emerging South Eastern European gas market, which in many countries of the region does not yet exist. TAP is expected to contribute about 10% - 12% of Italy's gas consumption, while, with its reverse flow, it will be possible to transfer gas through Albania and Greece to the rest of South Eastern Europe.

8. ESTABLISHING A REGIONAL GAS HUB

8.1. WHICH TYPE OF HUB FOR SE EUROPE?

For reasons stated in earlier chapters it is desirable to consider the setting up of a regional Gas Trading Hub to take care of the needs of the South East European area. At a time when nine (9) such hubs operate across Europe proper it is rather odd that an area of almost equal size and through which substantial gas quantities are already being transmitted (with a lot more planned) does not have one single hub where gas quantities can be freely traded. The answer of course lies in the fact that today the regional market of South Eastern Europe lacks the necessary liquidity in terms of gas volumes and worse it remains terribly isolated between its various sub regions – through the lack of interconnectors – but also from the main European gas market, again through the lack of major connections.

However, as has been argued in Chapter 6, the gas supply and gas transmission situation is likely to change after 2018-2019, when substantial new gas quantities are expected to enter the region via Turkey and Greece (through the TANAP – TAP gas system) and through the South Stream, via Bulgaria and Serbia. In addition, it is anticipated that some sizeable new gas storage will become available through Greece's planned two FSRU projects (Alexandroupolis and Kavala), the South Kavala gas storage facility, Bulgaria's expanded Chiren storage area and potential new storage capacity in Turkey, Romania, Serbia, Hungary and Slovenia. These new quantities, channeled through main trunk pipelines and a web of interconnectors, which are expected to be in place by that time, will enable the trading initially of marginal quantities and at a later stage, as the gas markets become more liberalized, of substantial quantities.

As has already been pointed out, the establishment and functioning of a Gas Trading Hub requires a deregulated gas market, which is not the case today in most countries of South Eastern Europe. During a complex process such as the deregulation of the natural gas sector, as a relevant Study published by the IEA observes, "the ultimate policy aim would be that the sector sustains itself by attracting outside investments to more efficiently serve its customers. However, to allow gas supply and demand to meet in a marketplace, a platform for exchange is needed, more commonly referred to as a hub" [6].

Physical vs. Virtual Hubs

In order to understand the parameters involved in the operation of a Gas Trading Hub, it is useful to consider some examples where the distinction is made between a physical hub and a virtual (regional) trading hub. Virtual trading hubs, such as NBP or TTF, do not exist in Southern and Eastern Europe. The region is now starting to perceive the concept of a liquid market where long-term contracts and spot or short-term trading are combined.

However, one could argue that the operation of a physical i.e. 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 physically meet and regional hub storage and LNG facilities are offered, 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. Trading at virtual hubs does not require physical access to the hub. Hence, a virtual hub is more favorable for liquidity purposes. On the other hand, at physical hubs, only gas passing at a precise physical location can be traded. At virtual hubs, pipeline congestion is not an issue and traders have higher flexibility. Therefore, by establishing national or transnational hubs competition can be enhanced [52]. Especially when moving towards an entry-exit system, virtual hubs are more suitable for gas trading. Furthermore, European experience to date has proven that virtual hubs present more rapid development than the physical hubs.

Which Type of Hub?

In examining the type of hub that would be more appropriate for a start-up operation in South Eastern Europe and as observed by the IEA, “one has to be aware that regardless of whether the hub is physical or virtual, when moving from physical balancing on the spot market to a liquid futures market, the physical gas supply and the virtual gas supply will meet at this hub. The natural gas hub will then bring together market participants that use the same natural gas market for different aims. This has consequences for the way that natural gas is traded, for the type of market participants active in the market, and for the products that are traded in the market” [6].

As defined by the European Commission Regulation 312/2014¹⁸, which has established a Network Code on gas balancing of Transmission networks, the Network Code aims at fostering the short term gas markets and providing price signals as well as contributing to the development of a competitive and efficient gas wholesale market in the EU and will apply from 1 October 2015. The Network Code set out “*gas balancing rules, including network-related rules on nomination procedures, imbalance charges, settlement processes associated with the daily imbalance charge and operational balancing between transmission*

¹⁸ The E.C. Regulation 312/2014 can be found at the Appendix.

system operators' networks". In accordance with the above regulation, the Transmission System Operator will be responsible for the operational balancing [53]. More specifically:

1. The transmission system operator shall undertake balancing actions in order to:
 - (a) maintain the transmission network within its operational limits,
 - (b) achieve an end of day linepack position in the transmission network different from the one anticipated on the basis of expected inputs and off-takes for that gas day, consistent with economic and efficient operation of the transmission network.

2. While undertaking balancing actions the transmission system operator shall consider at least the following in respect of the balancing zone:
 - (a) the transmission system operator's own estimates of demand of gas over and within the gas day for which the balancing action(s) is (are) considered;
 - (b) nomination and allocation information and measured gas flows;
 - (c) gas pressures throughout the transmission network(s).

3. The transmission system operator shall undertake balancing actions through:
 - (a) purchase and sale of short term standardized products on a trading platform; and/or
 - (b) the use of balancing services.

4. While undertaking balancing actions the transmission system operator shall take into account the following principles:
 - (a) the balancing actions shall be undertaken on a non-discriminatory basis;
 - (b) the balancing actions shall have regard to any obligation upon transmission system operators to operate an economic and efficient transmission network.

Looking more closely at the South Eastern European scene and in particular Bulgaria, Greece and Turkey and taking into consideration the much higher gas volumes that will become available after 2018-2019, and therefore the need to trade at first marginal and at a later stage even main gas volumes, it becomes apparent that some sort of Gas Trading Hub will be desirable for serving the needs of the broader region.

In this respect, Greece's Gas Transmission Operator (DESFA) is already developing the necessary infrastructure, partly in the context of EU regulatory requirements, but also taking a longer term view, in order to meet market coupling requirements, to satisfy anticipated commodity movements and capacity building. In this respect, DESFA is set to have a fully functioning balancing platform, which will be able to accommodate full trading

requirements, by October 1, 2015. However, according to DESFA's plans, the operation of the balancing point is expected to start in the first semester of 2016.

At this point it is important to note that Bulgaria's TSO, namely Bulgartansgaz, is in touch with Greece's DESFA concerning its access to the platform that Greece's TSO is now developing. As a result, cooperation between Greece and Bulgaria has already begun through their participation in the same common platform. In this respect, with Greece and Bulgaria both being EU member countries, and hence under obligation to comply with Directive 312/2014, we may observe that the foundations for the transition to a hub type regime and the free exchange of gas volumes have been laid.

In view of the above positive development concerning cooperation between Greece and Bulgaria and assessing the gas market situation in Greece, Bulgaria and Turkey post 2018, we see that Greece is likely to emerge as a forerunner for the setting up and operation of a regional Gas Trading Hub for a number of reasons which can be summarized as follows:

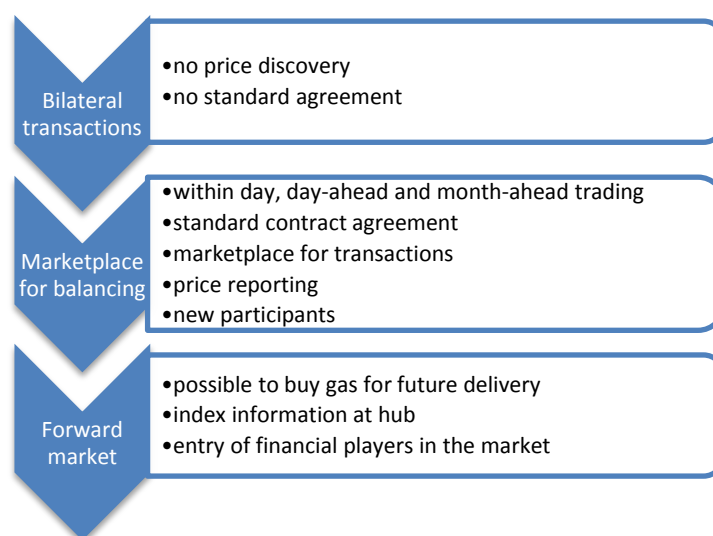
- i. By 2018-2019 the Greek market will enjoy much higher liquidity than Bulgaria, as extra gas quantities will become available from TAP, through the Greece-Bulgaria Interconnector, one or possible two FSRU units, additional gas from the Revithoussa LNG plant where a 3rd storage unit of more than 70.000 m³ will be available, and possibly more gas from the South Kavala Gas Storage facility, which is likely to operate by that time (see Appendix).
- ii. The Komotini-Alexandroupolis axis, which is a continuation of the existing Greek-Turkey interconnector, appears to be the main activity area in terms of inputs and outputs which will facilitate gas movements. This axis appears to combine more advantages compared to Bulgaria, and say the corresponding Varna-Sofia axis, as it will have several entry and exit points with substantial anticipated gas storage capacity.
- iii. A Gas Trading Hub located in Greece has certain distinct advantages for an outside trader over one in Turkey, and the Istanbul vicinity in particular. These advantages appear because the Hub is located within the EU, where a specific legislative, fiscal and tax regime applies, similar to that under which the other existing European gas hubs operate.
- iv. Already interest has been expressed by traders to export limited gas quantities to Turkey through the existing Greece-Turkey Interconnector (IGT), although a fully commissioned reverse flow operation is not yet available. Once DESFA's platform will become operative such exchanges will be facilitated.

8.2. BASIC PARAMETERS INVOLVED IN THE DEVELOPMENT OF A REGIONAL NATURAL GAS HUB

The establishment of a regional natural gas hub is expected to facilitate the wholesale trading of natural gas between participants in South Eastern 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.

Based on the developments observed, it is possible to identify different stages of market development towards a liquid hub. These include: (i) Bilateral transactions, (ii) Marketplace for balancing and (iii) the development of a Forward market. As already mentioned, the natural gas market in South Eastern Europe is in the phase of bilateral transactions.

Figure 70. Stages of market development.

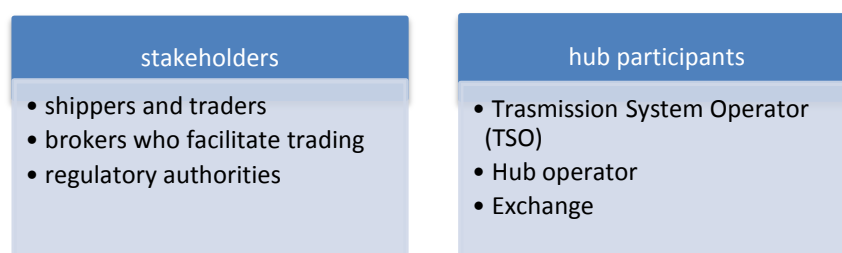


Source: Eclipse Energy Group

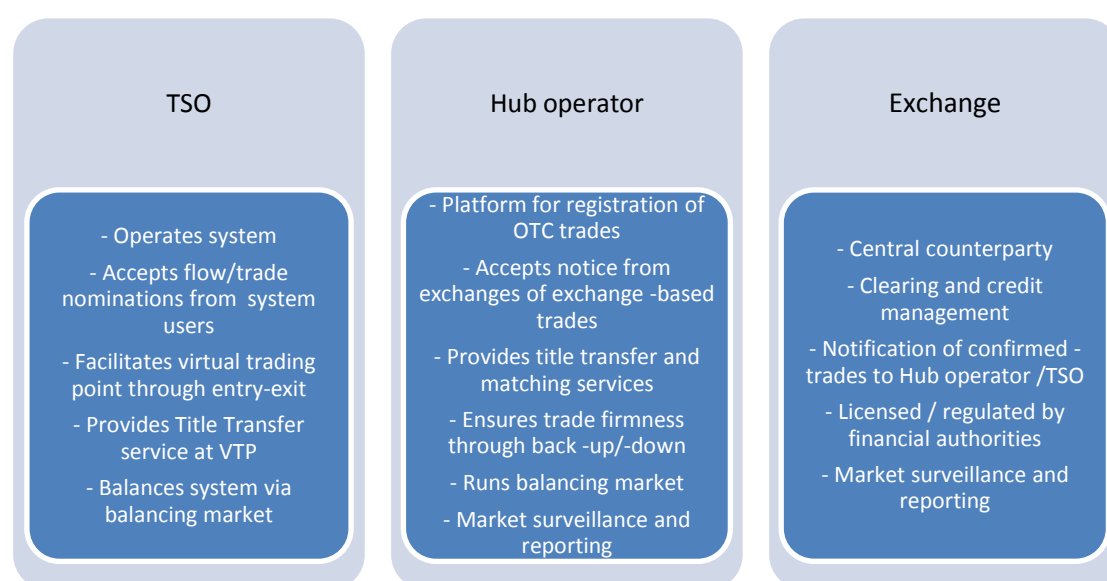
8.2.1. GENERIC HUB DESIGN AND ROLES OF HUB PARTICIPANTS

The stakeholders of a hub include network users and traders, brokers and regulatory authorities. Network users i.e. shippers that deliver gas to consumers can use the spot market as a balancing tool for their portfolio. Shippers are responsible for balancing their portfolios¹⁹ in order to minimize the need for the TSO to implement balancing actions. Brokers act as mediators for market parties facilitating the search for counterparties to sell/buy gas. On the other hand, the operation of a natural gas hub usually involves a Transmission System Operator (TSO), a hub operator and an exchange.

¹⁹ Balancing their inputs against their off-takes.

Figure 71. Stakeholders and hub participants.

The roles of the hub participants are presented in Fig. 72, as described by the European Federation of Energy Traders (EFET) [54].

Figure 72. Roles of hub participants in the case of a Virtual Trading Point.

Source: EFET

More specifically, the functions of the hub participants can be described as follows:

The **TSO** has the responsibility to ensure that the system is physically balanced. This is carried out by performing balancing actions²⁰. Furthermore, the TSO handles the capacity to and from the hub, and conducts the transfer of ownership rights. Gas transfer between two balancing portfolios is made through nominations i.e. trade notifications made to the TSO. The TSO is obliged to provide a balancing platform for network users in order to register bilateral trades. The balancing platform is essentially a trading platform where a TSO is a trading participant to all trades. The TSO can also buy and sell gas on the balancing market. In addition, it will carry out any residual balancing of the transmission networks if necessary.

The *trading platform*, which is provided by the TSO, according to the Commission Regulation 312/2014, must satisfy certain requirements:

²⁰ A balancing action is an action undertaken by TSO in order to change the gas flows onto or off the transmission network, excluding those actions related to gas unaccounted for as off-taken from the system and gas used by the TSO for the operation of the system [55].

- i. It must provide sufficient support to network users to trade in and the TSOs to undertake balancing actions through trade.
- ii. All market participants must be provided non-discriminatory access.
- iii. Services should be provided on an equal treatment basis.
- iv. It must guarantee anonymity in trading (at least until the conclusion of a transaction).
- v. The trading platform must also offer a detailed overview of the current bids and offers to all trading participants and
- vi. It must ensure the timely notification of all trades to the TSO [55].

A **Hub Operator**, the services of which can be provided by the TSO, operates the balancing market, supervises operational completion and provides reporting and surveillance. Moreover, it provides matching and title transfer services, stimulates product development and facilitates transfer of gas.

The gas **exchange** allows anonymity in placing orders and manages counterparty risk. If a buyer or seller chooses the exchange to place an order, the gas exchange operator will perform the nomination on behalf of the shipper. It will also notify the hub operator (or the TSO) of confirmed trades and is responsible for clearing and price reporting. Gas exchanges are usually licensed by financial authorities.

The establishment of a gas exchange with a spot and futures market that provides a reliable price signal is considered to be a key attribute of a competitive natural gas market. Although one cannot force market participants to trade in the exchange, the objective is to establish an effective and attractive exchange in terms of operation, products and fees.

The exchange operators and TSO of the main natural gas hubs in Europe are presented in Table 33.

Table 33. Basic structure of European marketplaces for natural gas.

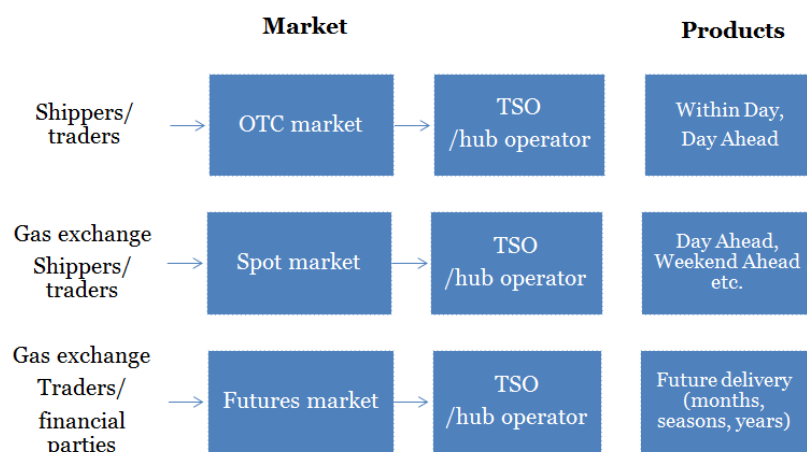
Market	Trading point	Exchange operator	TSO
UK	National Balancing Point (NBP)	ICE Endex	National Grid
Netherlands	Title Transfer facility (TTF)	ICE Endex	Gasunie Transport Services
Germany	Net Connect Germany (NCG)	EEX	Open Grid Europe
	Gaspool	EEX	Gascade
France	Points d'échange de gaz (PEGs)	Powernext	GRT Gaz
Belgium	Zeebrugge Beach	Huberator	Fluxys
	Zeebrugge Trading Point	APX, Zeebrugge BV	Fluxys
Austria	Central European Gas Hub (CEGH)	Wiener Boerse AG	Gas Connect Austria (GCA), Baumgarten Oberkappel Gasleitungsgesellschaft (BOG) and Trans Austria Gasleitung (TAG)
Italy	Punto di Scambio Virtuale (PSV)	GME	Snam Rete Gas

The natural gas hub will basically serve as a common transaction point for a number of “sub-markets”. The spot market is essentially a physical market with delivery obligations used for short-term, balancing purposes by shippers. Besides the spot market, a futures market can

be realized. While in a spot market gas is traded for a limited time into the future, in a futures market gas products are traded with delivery at a future date, such as months or years in the future. The futures market is a financial market and attracts non-physical players in order to hedge exposure. Physical parties (shippers) use the spot market in order to balance their portfolio and are usually less active on the futures market. Nevertheless, when moving from physical balancing on the spot market to a futures market, the physical gas supply and the virtual gas supply will meet at this hub - irrespective of whether the hub is physical or virtual [6].

By establishing a liquid futures market, shippers and financial players will become more active, trading in the OTC market as well as the exchange will increase, new products will be developed and the trading volume of products with future delivery will also increase. Consequently, the resulting prices on the spot and futures market will increasingly reflect supply and demand in a region. Market activity will be facilitated by the exchange operator, which will provide anonymous screen-based trading, and potentially brokers. Those companies who wish to participate in the exchange will have to become members and will be charged with a fee.

Figure 73. Proposed hub design.



8.2.2. CONDITIONS FOR THE SUCCESSFUL OPERATION OF A NATURAL GAS HUB

Diversification of supply

The first prerequisite for the successful operation of a natural gas hub is its ability to attract and establish multiple supply options, i.e. multiple entry points. It is of critical importance that the hub can offer shippers the flexibility to change supply sources, routes and markets through interconnecting pipelines. Availability of storage and reliable transport mechanisms are also vital, along with supply optionality, for the successful operation a gas hub.

Moreover, diversification of gas supply sources is crucial for ensuring security of supply, a major concern as far as EU energy policy is concerned.

Liquidity

At the start, it is necessary that potential market participants express interest in participating in such a hub, thus ensuring initial activity. As already mentioned, establishing a virtual hub constitutes a boost for liquidity in a natural gas market. A number of factors which contribute in increased liquidity are the following:

- The number of active trading parties
- The number of transactions concluded
- Volume nominated within the hub in per cent of volume traded
- Volume delivered physically in per cent of volume traded
- The existence of market participants who are always willing to buy and sell
- The volume that can be traded without moving the market
- Price volatility and price differentials between hubs
- The ability to find counterparts for any given size of transaction
- The variety of services / products offered at the hub
- The size of bid-offer spreads in the market
- Flows of gas between hubs
- Utilization of capacity on the routes between the relevant hubs [56].

As the hub becomes more liquid, it will attract non-physical parties. Their trading will in turn increase the liquidity of the hub.

Transparency

Transparent trading is a necessary condition for the development of a gas hub. Product price must be transparent and all participants must have access to information. Establishing a range of indices can help to ensure price reporting on a regular basis. Building a regulated trading platform can also contribute to creating a transparent environment which will provide reliable published prices. A transparent reference price for the gas market would deliver a reliable price signal that accurately reflects regional supply and demand, support the liquidity of the market and help establish the gas trading hub as a price setting point for South Eastern Europe. It would also increase overall participation in the gas market by attracting large users (such as LNG plants, industrial users and gas-powered generators). The introduction of competition in the market can help to achieve an increased price transparency level. Trading of balancing energy must also be non-discriminatory.

As it is argued that some traders might try to manipulate index prices by misreporting trading to the daily price publications, efficient monitoring between traders on reported prices, as well as auditing of the prices used to value the trading portfolios, can enhance transparency and the reliability of the published prices [57].

Reliable delivery mechanism

Another important prerequisite for a successful gas market is a reliable delivery mechanism. Shippers need to have uninterrupted access to capacity. Buyers need to be able to physically receive gas and sellers need to be able to deliver gas. If there is not enough gas available in the network, incentives have to be provided to the shippers to supply the network with gas. Increased hub functionalities and back-up services can enhance the “firmness” of a hub and improve the availability of gas volumes. Managing fluctuations in supply and demand is also critical and can be reinforced with flexible storage facilities.

As far as the financial players are concerned, if there is not enough volume to back up the physical delivery, the risk becomes higher for financial trading. A reliable delivery mechanism preserves the link between the financial position and the physical need and therefore, provides incentives for trading.

Standardization

Standardization (contracts with standard features and terms for trading) and making gas a tradable commodity are essential for the ability of the hub to “pool” transactions such that they can provide net positions. Creating standard products allows shippers and traders to trade quantities of gas labelled as a “product” by their time of delivery. Moreover, creating standard gas products that a number of companies can easily trade enables financial parties to value the products and start trading them on the futures market [6].

In quantitative terms, there is a set of indicative criteria for assessing the functionality of a wholesale gas market, established in the framework of the European Gas Target Model (GTM1).

a. Churn rate

The churn rate, as already mentioned, is the volume of gas traded relative to physical volume. According to the aforementioned model, churn rate must be greater than or equal to 8.

b. Target Market zone size

Target market zone size, i.e. the consumption of gas by consumers within a market zone, must be greater than or equal to 20 bcm (215 TWh).

c. Number of supply sources

The number of supply sources, which corresponds to the number of countries imports originate from, must be at least 3.

d. HHI (Herfindahl Hirschman Index)

The Herfindahl Hirschman Index is a measure of concentration amongst suppliers based on energy measured by firm. The Index must less than or equal to 2.000.

e. RSI (Residual Supply Index)

The Residual Supply Index is essentially the share of consumption which can be met without the largest supplier based on supply capability, i.e. capacity (again on firm level). The RSI must be greater than or equal to 110% [58].

However, as the Gas Target Model is currently being revised, the above set of criteria will be enriched with additional relevant criteria, which will constitute the criteria of the updated Gas Target Model.

8.2.3. A NATURAL GAS HUB FOR SE EUROPE

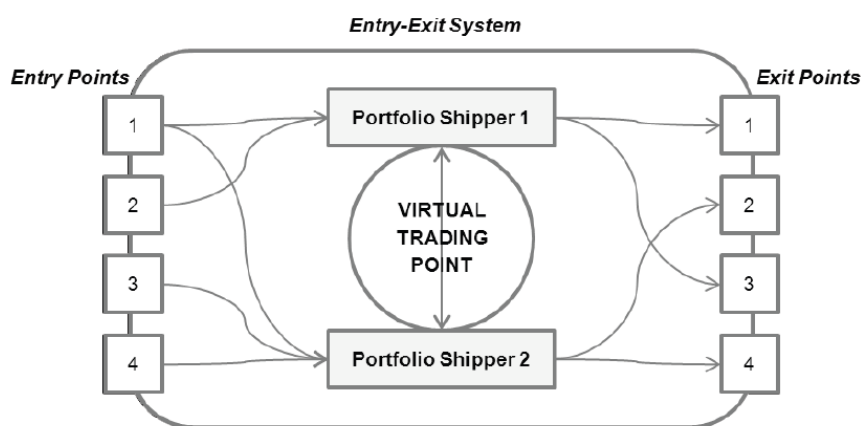
A regional hub can provide a marketplace for shippers and traders from countries in the region and hence enhance liquidity in the wholesale gas market of South Eastern Europe, a region where market concentration remains high [54]. The operational framework of the hub must be clearly defined, as a regional hub would span multiple regimes and regulatory jurisdictions.

Regulation 715/2009 of the European Parliament and of the Council points out that in order to enhance competition, it is important that natural gas can be traded independently in the system. Therefore, network users need to be able to book entry and exit capacity independently. This means that TSOs should have a de-coupled entry-exit system in place [59].

According to a study prepared for the European Commission, “an entry-exit system is a gas network access model which allows network users to book capacity rights independently at entry and exit points, thereby creating gas transport through zones instead of along contractual paths. The independence of entry and exit capacities is further supported by a virtual trading point where network users who have booked entry or exit capacity can sell or buy gas, respectively” [60]. The EU model of TSO entry/exit systems, therefore, inherently incorporates virtual trading points. The establishment of such virtual trading points is of course the vital step or prerequisite for the emergence of a virtual trading hub which, in our case, is the ultimate goal.

Since the development of Regulation 715/2009, EU member states have been trying to implement entry-exit systems and have developed different solutions while implementing them. If a regional hub was created in South Eastern Europe, it would require an entry-exit system across multiple TSOs, covering different regulatory systems.

Figure 74. Scheme of an Entry-Exit system.



Source: IEFE

Gas hub location

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 pipeline connections planned in South Eastern Europe, as well as two FSRU facilities and an underground storage unit in Northern Greece. Both Greece and Turkey have expressed interest in establishing a gas hub for the region.

Storage will also play an important role in providing physical gas flexibility. All storage capacity within a market area should be made available to market participants on an equal non-discriminatory basis. 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 (See Appendix for a detailed presentation of the underground storage facility in South Kavala).

A regional hub must combine market liquidity (i.e. gas volumes), experience in market operation, transparency of financial transactions, as well as the ability to accommodate trade volumes from neighboring markets. Finally, the regional gas hub must have links with other European gas hubs and attain European approval and recognition. In regional gas hub selection all the different characteristics of the three neighboring markets (Turkey, Bulgaria, Greece) will have to be taken under consideration:

8.2.3.1. THE CASE OF TURKEY

The Turkish economy, as well as Turkish energy demand, is growing rapidly. Turkey has the largest energy market in the region in terms of volume and several entry points for both pipeline transmission and LNG deliveries (6 at present, 8 potentially). 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 natural 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 [61]. 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, with a deadline for the 1st of January in 2015, 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 [62]. 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 natural 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.

The liberalization of the power market was intended to be the locomotive for the liberalization of the gas market, but its pace has slowed down. EPIAS, the Turkish energy exchange, has not been formally incorporated yet and the start date of the platform operation is in question, as it was initially announced that it would start operation by October 2013. Nonetheless, Mustafa Karahan, vice chairman of Turkey's Energy Traders' Association stated that the process of inviting private companies to apply to take a stake could be completed by the end of the summer 2014.

Another important issue is that Turkish legislation does not include special transit provisions that would make it align with the EU regulatory framework. More specifically, it provides for two different market models: “Transit” and “Re-export”. As the Oxford Institute for Energy Studies points out in a relevant study, the creation of a hub in Turkey would have to include a regime that would regulate gas imports into Turkey and re-exporting gas to the European market, with the involvement of the private sector. It should be noted that as yet there is not a re-export provision in Turkey’s transit agreement with Azerbaijan. Re-exporting gas should be allowed in the agreements between buyers and sellers, if Turkey is to become a natural gas trading hub [63].

According to the Oxford Institute for Energy Studies, “Turkey could become either:

- a physical gas trading hub, with import and export pipelines, connections with other physical hubs mainly via interconnectors, access to storage and gas title transfer among actors trading, or
- a commercial hub 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”.

As far as Turkey’s target market zone is concerned (see p. 177), this will easily exceed the limit of 20 bcm.

8.2.3.2. THE CASE OF GREECE

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 (Bulgaria, 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 2017. In May 2014, Greek natural gas transmission system operator DESFA announced the completion of the first phase of the works for the second upgrade of the border metering station in Sidirokastro, part of the main Transit Balkan Pipeline which brings Russian gas to Greece via Bulgaria, enabling natural gas exports towards Bulgaria. Currently, there is no gas interconnector to Italy, but the operation of TAP, the construction of which will start in 2016, will allow for more diversification in gas supply paths. Moreover, the development of the Southern Corridor can allow Greece to become the entry point for significant gas volumes flowing from the Caspian region and towards the EU market.

Greece is currently stepping up efforts to create a functioning wholesale market. DESFA, a majority state-owned company, is an independent TSO which operates both the national grid and the Revithoussa LNG terminal. DESFA belongs to DEPA.

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

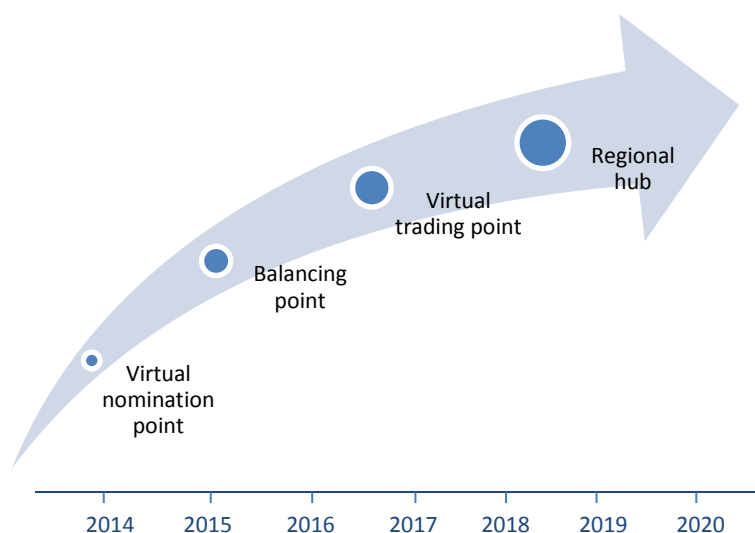
the incumbent DEPA and Algeria's Sonatrach. Consumers who want to have access to gas without contracting with DEPA need to make a bilateral contract with a supplier of LNG and book capacity in the LNG terminal separately.

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.

The TSO is currently in the process of developing a platform for secondary trading of gas as well as a virtual trading point, where offers for the resale of gas and transfer of transmission capacity rights can be submitted and accepted.

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. From October 1, 2015, the virtual point is set to serve as the Greek Balancing Point System. However, the Greek TSO (DESFA) estimates that the Greek Balancing Point will start operation in the first half of 2016. This means in practice that there will be a platform for the operation of the wholesale gas market as well as performing balancing actions. Consequently, this platform can become the basis for the operation of a Virtual Trading Point, given that the second revision of the Network Code includes the implementation of an Entry-Exit System and a Virtual Trading Point. Historically, all hubs – physical or virtual - started their operation as Balancing Points and gradually some of them evolved into Trading Points with longer forward curves, as they managed to create adequate liquidity. Once liquidity is increased, the Virtual Trading Point can potentially evolve in a regional hub.

Figure 75. Proposed road map for the development of a natural gas hub based in Greece.



It is anticipated that by 2020 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 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 possibly another one in Kavala, 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. In this context, Greece's target market zone could equal or exceed the limit of 20 bcm, as the broader geographical area of its market will, in addition to its domestic market, encompass Bulgaria, Romania and part of Turkey.

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 Greek stock market 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 around 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.

8.2.3.3. 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, in Romania there were extensive protests against shale gas exploration [64].

Romania is obliged to comply with EU requirements for gas market liberalization and unbundling. The legal unbundling of the distribution and supply activities of distribution/supply operators was completed in 2007 – 2008. The state owns the majority of

shares in Transgaz SA, the Transmission System Operator for gas. The OPCOM gas exchange is already in operation, with OMV Petrom Gas putting OPCOM gas for auction for the first time in February 2014.

In the Romanian gas market natural gas price is still not based on offer and demand, but is a 'basket price' set by ANRE, the Romanian National Regulatory Authority, i.e. an average of domestic and import prices weighted with the respective quantities. However, complying with the EU regulatory framework will eventually lead to abandoning the subsidized "social" tariff. Gas market liberalization is expected to be completed by the end of 2014, with a possible extension to December 31, 2015.

Romania is interconnected with Hungary, while reverse flow interconnections with Bulgaria and Moldova are to be completed in 2014. More specifically, a new two-way high-pressure natural gas interconnection between Romania and Bulgaria is planned to become operational in the summer 2014. This project is expected to increase the security of supply for natural gas by diversifying gas sources within Romania and Bulgaria, as well as within the region (Greece, Hungary and Turkey). With the full development of Shaz Deniz II field – not achievable before 2020 - the aforementioned interconnectors will be able to supply Romania with Azerbaijani gas [65].

It should also be mentioned that Romania hoped to host part of the Nabucco gas pipeline, but it abandoned its plans when it was decided by the Shah Deniz II Consortium to select the TAP project for transporting gas from Azerbaijan to the EU. The AGRI Project (Azerbaijan-Georgia-Romania Interconnector) could also prove to be a new way for Romania to access the gas reserves in the Caspian region. By materializing the AGRI project, Azerbaijani gas will be transported via pipeline to the Black Sea coast of Georgia, where the gas will be liquefied at a special terminal and directed afterwards towards Romania and other European countries via LNG vessels. The feasibility study for this project is being concluded.

8.2.3.4. THE CASE OF BULGARIA

Bulgaria is a small market, but will soon become the European entry point for the South Stream pipeline. At present, it has one entry point and 4 potential ones. It also has the advantage that it operates within EU jurisdiction.

Bulgaria needs desperately to diversify its gas supply sources. It should be noted that in 2012 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.

The participation of Bulgaria in the EU Internal Gas Market proves to be a difficult task as the natural gas sector has still certain inefficiencies to overcome.

Bulgarian Energy Holding is a state enterprise and holds monopoly rights for gas supply and transmission, through its subsidiaries Bulgargaz EAD, the state natural gas distribution

company and Bulgartransgaz EAD, the Bulgarian Transmission System Operator. Bulgaria has so far avoided ownership unbundling and establishing an Independent System Operator. However, in order to comply with the EU regulatory framework, Bulgaria needs to ensure the legal and functional unbundling within Bulgartransgaz. Nevertheless, Bulgartransgaz is still undergoing a process of certification as an independent TSO.

Providing third-party access to main gas transit pipelines to Greece and Turkey encountered problems especially in the past, because these pipelines are not under EU jurisdiction and are not part of the Bulgarian regulated network. On the contrary, they are regulated by intergovernmental agreements with the Russian Federation. Changing the legal framework under which these pipelines operate would demand a combined effort from Turkey, Greece, Bulgaria and Romania, as Russia is not considered very willing to alter these agreements. However, nowadays Russia appears more willing to concede to the application of EU directives, especially related to energy security, as is the case with the implementation of the Bulgaria – Greece reverse flow capability at the Sidirokastro entry point. In that respect, the reverse-flow gas grid interconnection Kulata/Sidirokastro was an important step towards improving regional cooperation. Greece's gas transmission network operator DESFA has announced its readiness to reverse gas flow through the aforementioned interconnection, which means that Bulgaria will be able to receive gas supplied from Greece in the case of a crisis. It should be remembered that towards the end of the 2009 crisis, some gas companies were able to inject natural gas in the Bulgaria-Greece pipeline from the Greek LNG terminal at Revithoussa. This did not signify reversed flow to Bulgaria, but Bulgaria was able to pump the injected gas into gas 'stored' in the transit pipeline [66]. Reverse flow gas grid-interconnection is also expected to be realized in the case of the Gas Interconnection Turkey - Bulgaria (ITB).

As far as Bulgaria's target market zone is concerned, it is not anticipated that this will exceed then 20 bcm limit before 2021 at the latest.

8.3. SWOT ANALYSIS

A SWOT analysis has been carried out in order to assess the strengths, weaknesses, opportunities and threats for the establishment of a regional gas hub in South Eastern Europe (see figure 76). The development of gas infrastructure will result in establishing multiple entry points in the region, further enhancing supply optionality for network users. The planned storage facility in South Kavala will also provide physical flexibility. The EU member states of the region will soon have a balancing platform, as they are obliged to align with the European regulatory regime. This will of course speed up the process of market liberalization in the region. In the region, there are exchanges with long history, such as the Hellenic Exchanges and the Istanbul Stock Exchange that could offer gas futures trading.

The creation of a gas hub in the region will introduce competition in the wholesale gas market and provide price signals that reflect supply and demand for natural gas traded in the region, thus enhancing transparency in the market. An over-the-counter market, as well as a gas exchange – which will offer spot and futures products - can be launched.

On the other hand, there is inadequate infrastructure to date, which results in a limited number of entry points for gas in the region. The balancing market is still at its early stage of development and state dominance in the gas sector of the region, at country level, sometimes impedes market liberalization.

Moreover, ensuring adequate liquidity in the market may meet some difficulties. Bureaucracy, which is usually problem in all the countries of the region, may also cause setbacks. In addition, not all the countries of South Eastern Europe are EU member states and the differences in the regulatory regimes may impede any kind of market integration. Finally, establishing a single node would prove notably difficult, as it would demand cooperation between different TSOs, and more importantly an entry-exit system across multiple TSOs, which will need to cover different regulatory systems.

Nevertheless, from the SWOT analysis one can clearly see that the apparent strengths of the regional gas hub far outweigh the perceived weaknesses. What is equally interesting lies in the opportunities sector and is related to gas price setting. According to experience so far from the operation of most European gas hubs, a distinct advantage of hub operation is the establishment of competitive gas prices which in most cases are valued lower than oil-indexed prices [17].

Figure 76. SWOT analysis for a gas hub in SE Europe.

<p>Strengths</p> <ul style="list-style-type: none"> • Multiple entry points in the future • Development of infrastructure on track • Planned storage facility will provide physical flexibility • Alignment with the European Union regulatory regime • Potentially multiple suppliers • Setting up of balancing platforms is on track • Exchanges with long history in the region (Athens, Istanbul) • Regional economy with positive prospects 	<p>Weaknesses</p> <ul style="list-style-type: none"> • Inadequate infrastructure to date • Inadequate storage facilities to date • Inadequate entry points to date • Non-existent balancing market to date • Different consumption profiles in the region • State dominance in the gas market at country level
<p>Opportunities</p> <ul style="list-style-type: none"> • Introduction of competition in the regional market • Establishing lower natural gas prices, which will reflect regional supply and demand • Promotion of transparency and predictability in natural gas prices • Establishing Over-The-Counter, as well as Exchange trading • Creation of a spot and futures market 	<p>Threats</p> <ul style="list-style-type: none"> • Possible difficulties in ensuring adequate liquidity • High possibility of bureaucratic delays • Differences in regulatory regimes of countries in the region • Possible difficulties in the cooperation between the different TSOs • Serious difficulties in establishing a single node: It would require an entry-exit system across multiple TSOs, which will need to cover different regulatory systems

8.4. A ROADMAP FOR SETTING UP A REGIONAL GAS HUB

Elaborating on the Road Map presented in Figure 75, for the establishment initially of a Greece - based gas trading hub, which could also serve the wider region, the obvious next step would involve the definition and description of the Entry-Exit regime and its implementation based on a virtual trading point.

A prerequisite for the operation of the Entry-Exit system is of course the existence of a wholesale gas market. In the case of Greece, such a market is still in the making. When we talk about market integration and the operation of a gas trading hub on a regional basis, it is implied that each country of the region, whose players will be participating as active participants in such a hub, will need to have established beforehand a wholesale market. In the case of Greece's immediate neighbours who are likely to participate in such a market, Italy has a mature wholesale gas market, while Turkey is in the process of establishing one as observed by the Oxford Institute for Energy Studies [63]. However, in the case of Bulgaria and Serbia, progress for the creation of wholesale gas markets is seriously lagging behind. On the other hand, Romania is fairly advanced in this respect as such a market is already functioning at a large extent, which means that gas volume exchanged through contracts could be possible between Greece, Turkey and Romania, once a regional hub comes into operation.

A second step for the setting up of the above natural gas hub will be the establishment of continuous consultation between hub operators, TSOs, exchanges, shippers and representative trading organizations. Next, the role of the Hub operator must be defined and the liquidity of the balancing market must be ensured. In the case of Greece, this is most likely to happen in the period between 2017-2019 when notable new gas quantities will gradually start becoming available (e.g. from the FSRU unit in Alexandroupolis, from TAP, via the existing Greece-Turkey interconnector and from Bulgaria via IGB). Before 2017 an energy exchange will have to be established. Finally, it must be stressed that the roles of the TSO, the hub operator and the exchange should be clearly defined.

Figure 77. Next steps.

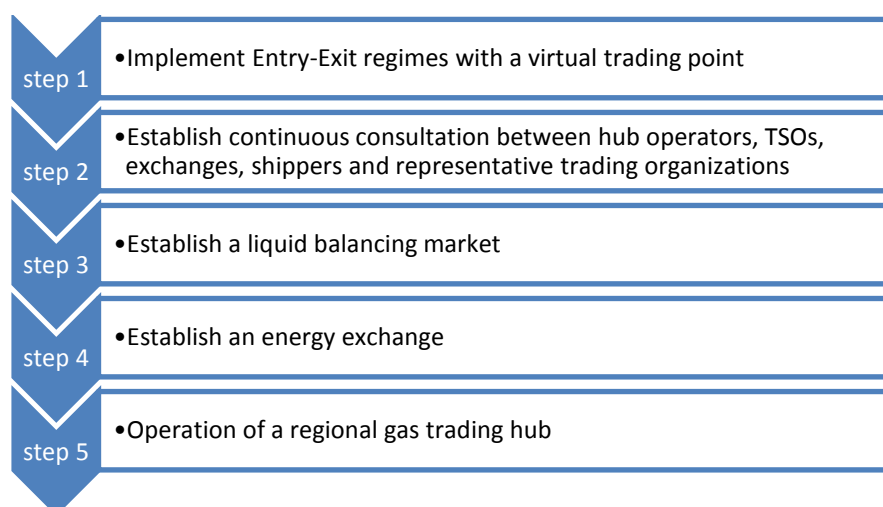
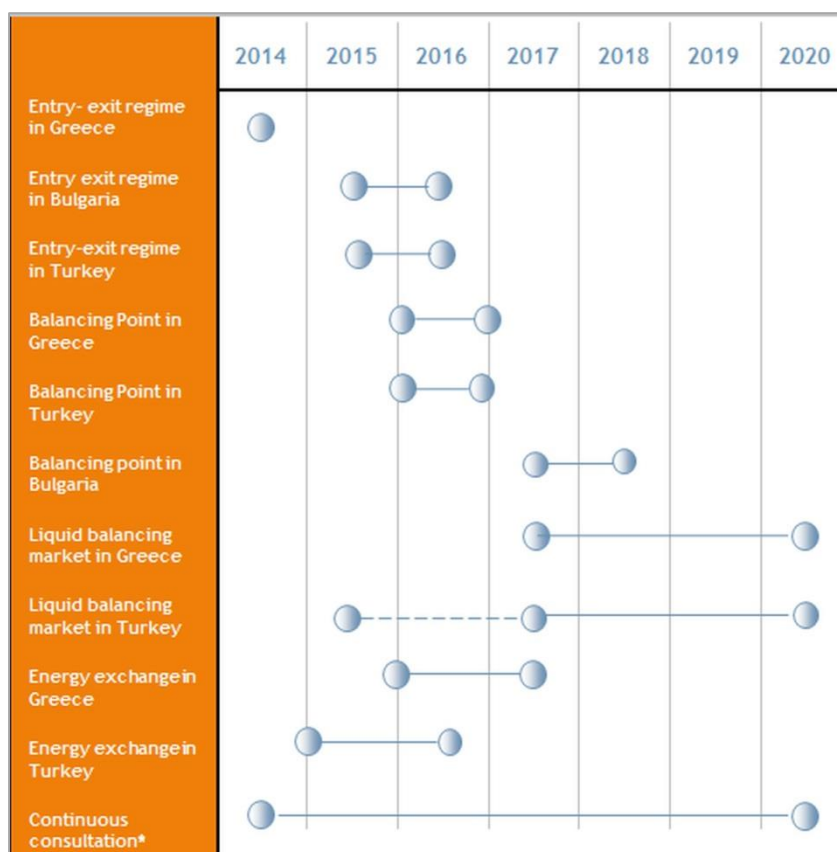


Figure 78. Roadmap for a regional gas hub.



*Greece, Turkey, Bulgaria

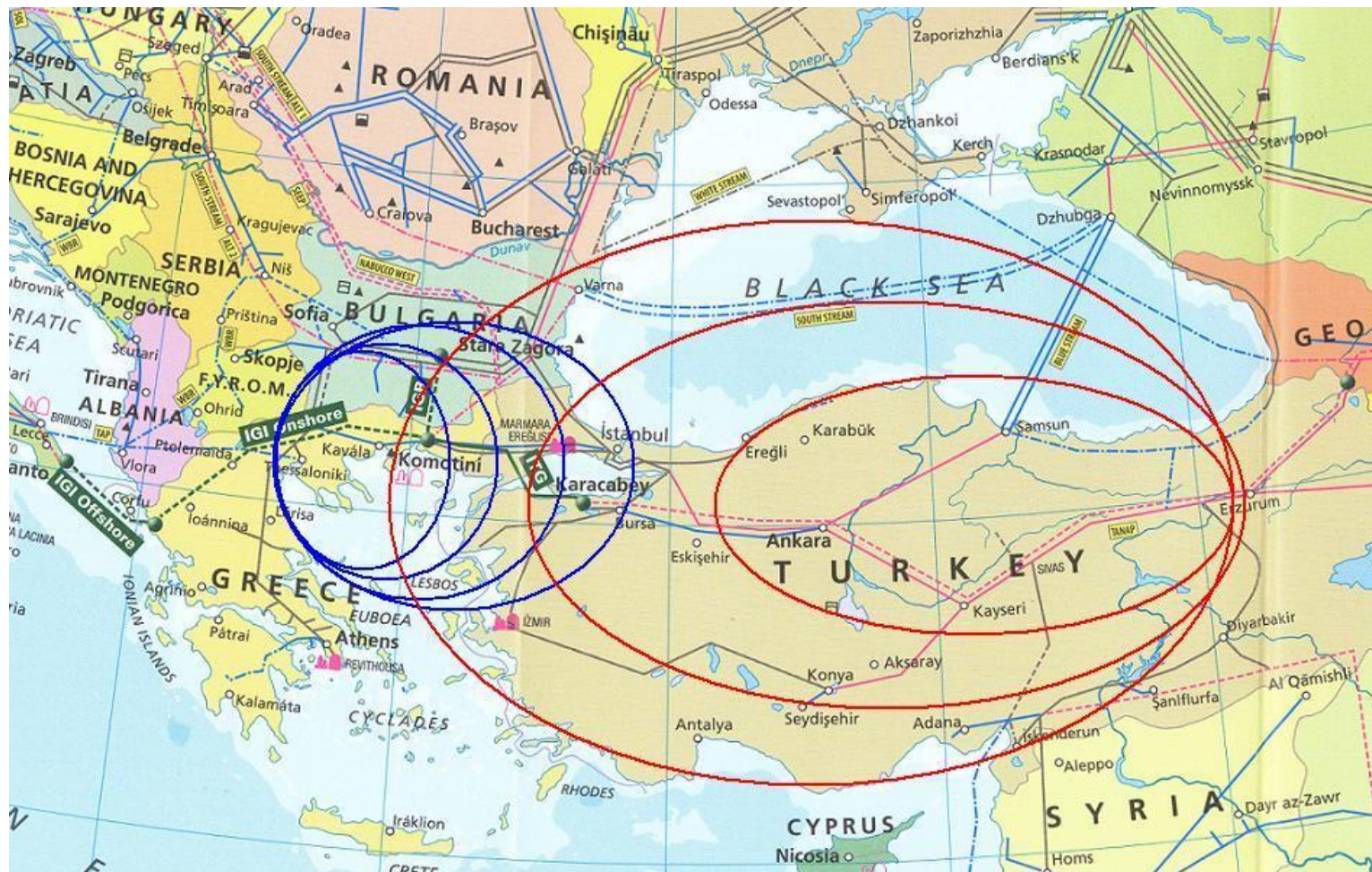
As risky as it may be from a forecasting point of view, Fig. 78 does precisely that as it attempts to show a road map for the entire region. It depicts a possible sequence of events taking place at different time intervals but also simultaneously (in the case of continuous consultation between the TSO's) in all three basic countries under consideration. The projected culmination of events leads to the parallel establishment of two major regional hubs, one in Thessaloniki linked to Athens Energy Exchange (in the process of being set up) and the second in Istanbul linked to the EPIAS Energy Exchange (to be established). With anticipated marginal gas volumes in the initial range of 1-1,5 bcm, annually for physical delivery by 2019-2020, possibly to be increased to 8-10 bcm by 2025-2026, it may well become possible to see the realization of such projections.

Although it is relatively easy as a concept to describe the specific steps that need to be taken when studying the setting up of a country defined gas price hub - which although it will be trading gas volumes regionally its contracts will be cleared by a specific energy exchange within the boundaries of the country – as was the case described in 8.2 for Greece and it is clearly shown in Fig. 75, the situation gets slightly more complex if we are to envisage parallel steps in three or four different countries. In such a case several unknown variables enter the picture and make it extremely hard to present the various steps in a logical sequence and furthermore assume that all different actions will converge somehow at one point in the future say by 2019 or 2020.

The broad concept is for the two regional gas hubs (in Thessaloniki and Istanbul) to handle between them the anticipated gas volumes that will be generated following the opening up of the regional gas market. A lot will depend on the trading conditions that each Energy Exchange will offer in terms of charges, speed of execution and clearance of orders and transparency. In a sense, having two regional exchanges will help considerably from a geographical aspect as the Istanbul one will take care of trades directed eastwards while the Thessaloniki one will deal with trades to the west and to the North. This proposed division of trading responsibility is of course one of several possible scenarios, but in our view it encompasses several advantages, the most important of which is the notion of competition (between the two hubs) right from the start. This will inevitably help to speed up developments in establishing the hub(s) and attracting active participants (traders).

Charting a Road Map for the introduction of free and competitive gas trading to cover the south part of the SE Europe Region is by necessity based on certain arbitrary, but realistic assumptions at this early stage. On the one hand, we have the gradual and planned steps by Greece's TSO for the setting up of a Virtual Nomination Point and Balancing Point as clearly foreseen in the EU Directive and on the other hand we have the ever growing Turkish gas market and its dynamic gas companies which will seek to establish sooner or later a trading platform to take care of their internal trading requirements. Establishing such a platform will by necessity lead to the formation of a much bigger, i.e. regional, trading hub.

Picture 37. The Thessaloniki and Istanbul Gas Trading Hubs will between them cover a wide geographical range and adjacent trading zones.



9. ECONOMIC IMPLICATIONS FROM THE OPERATION OF A GAS HUB IN SE EUROPE – A DISCUSSION

From whichever perspective one should examine the setting up and operation of a regional gas trading hub, there are important economic implications 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 being that we are introducing a completely new approach, together with a new and inclusive price-setting regime into a market where none existed before; other than bilateral negotiations based on strict oil-indexed contracts. These bilateral arrangements still determine the price of gas in our region – Bulgaria, Serbia, Romania, Greece, Turkey – which is predominantly supplied via pipeline. 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 itemized as follows:

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

In order to discuss the economic implications from the operation of the proposed regional gas trading hub, a number of assumptions have to be made in terms of geography, infrastructure and its 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 to 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 South Kavala Gas Storage facility
 - IV. At least one floating LNG storage and gasification unit (FSRU), say the one in Alexandroupolis.

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

Table 34. Cost of planned gas infrastructure projects.

Natural gas Project	Cost ²¹
IGB	€180 million
TANAP	€805 million (with TANAP's cost corresponding only to Turkey's European ground route)
TAP	€3.900 million
South Kavala UGS	€400 million
FSRU	
Alexandroupolis	€270 million
FSRU Kavala	€270 million
Total	€5.825 million

We must point out that the above cost estimate is specific to the present regional gas trading hub 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 operation by 2019. The weakest link in all of the above is the South Kavala UGS, the development of which has stalled following intervention by the Greek government.

3. The origin of natural gas will be as follows:
 - I. For pipeline gas: This will originate from Azerbaijan, from the Turkish grid and Russia (via South Stream at IGB).
 - II. For LNG: Qatar, Nigeria, Algeria, Norway, USA, East Med.
4. In view of the information available for the gas volumes corresponding to long term contracts through TANAP-TAP, the available capacity of the pipelines involved (ie. IGB, IGT, Bulgarian Greek Main Pipeline) and gas demand projections for 2020, one could safely assume that some 1,0 to 1,5 bcm of gas will be available for trading as early as 2018, rising to 6,0 and possibly to 10,0 bcm and more by 2025. In addition to that, one should take into consideration a realistic churn ratio, however hard this may be to predict. Given the experience of European trading hubs, churn ratios may vary from 1 up to 18 [29].

²¹ The exchange rate used is EUR/USD =0,7338.

On the basis of the above mentioned 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 35. Scenarios for trading activity in the regional natural gas hub.

Gas volume physically delivered (bcm)	Churn Ratios	Traded gas volume (bcm)	Traded value* (in million €)
1	1,5	1,5	462
	2	2	616
	2,5	2,5	770
	3	3	925
	4	4	1.233
	5	5	1.541
2	1,5	3	925
	2	4	1.233
	2,5	5	1.541
	3	6	1.849
	4	8	2.466
	5	10	3.082
3	1,5	4,5	1.387
	2	6	1.849
	2,5	7,5	2.311
	3	9	2.774
	4	12	3.698
	5	15	4.623

*Based on an average price of \$420 per 1.000m³ for 2Q2014 for Gazprom gas deliveries in SE Europe (exchange rate used EUR/USD =0,7338).

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 €5,8 billion, while it will be generating substantial financial turnovers on a yearly basis. Starting from a modest €1-1,2 billion and rising to €5 billion and beyond in the first two to three years, depending on available quantities. If, for example, 8 bcm were to become available by 2023-2024, with a conservative churn ratio of 5, the value of gas traded could exceed €12,3 billion at current prices.

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 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, 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.

In the case of the proposed regional South Eastern European Gas Hub, we believe it is premature to try and predict the evolution of a gas price regime after 2018-2019, 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 would be created by the proposed gas trading hub, traders would be willing to buy available gas (ie. 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 of the two planned FSRUs).

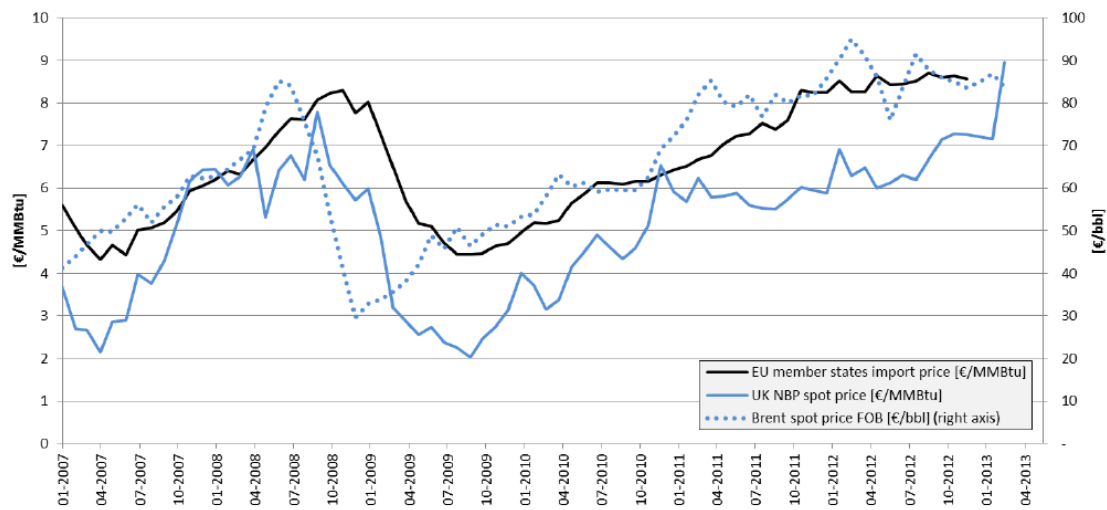
The operation of the proposed South Eastern Europe Gas Trading Hub is therefore predicted to have a positive effect on wholesale markets in all three countries by channeling needed gas volumes at competitive market rates. If we are to judge from the price history of selected European gas hubs, as shown in Figures 79-80, one should expect a marked differentiation from oil indexed prices. This 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.

It is worth comparing the NBP spot price – which acts as an indicator for Europe’s wholesale gas market – with the average gas import price into EU member states. In Figure 78, natural gas import prices, which reflect gas prices mainly based on long-term oil-indexed contracts, and NBP spot prices, which reflect gas-on-gas competition, are plotted against the Brent spot price. One can observe that the NBP spot price is consistently lower than the gas import price, apart from 2008, when the financial crisis unfolded. According to a study prepared by the Directorate General for Internal Policies of the European Parliament, EU natural gas import prices increased by 93% (from 4,3 €/MMBtu to 8,3 €/MMBtu) between April 2007 and November 2008, before returning to 4,4 €/MMBtu in August 2009. It is clear that natural gas prices followed the trend of crude oil spot prices, which increased by 107% from 41 €/bbl to 85 €/bbl, between January 2007 and June 2008, before falling to 30 €/bbl in December 2008. As the study points out, the NBP price and the average import price into

European member states follow the trend of the crude oil spot price in general, with a time lag of about 3-4 months and 4-6 months, respectively.

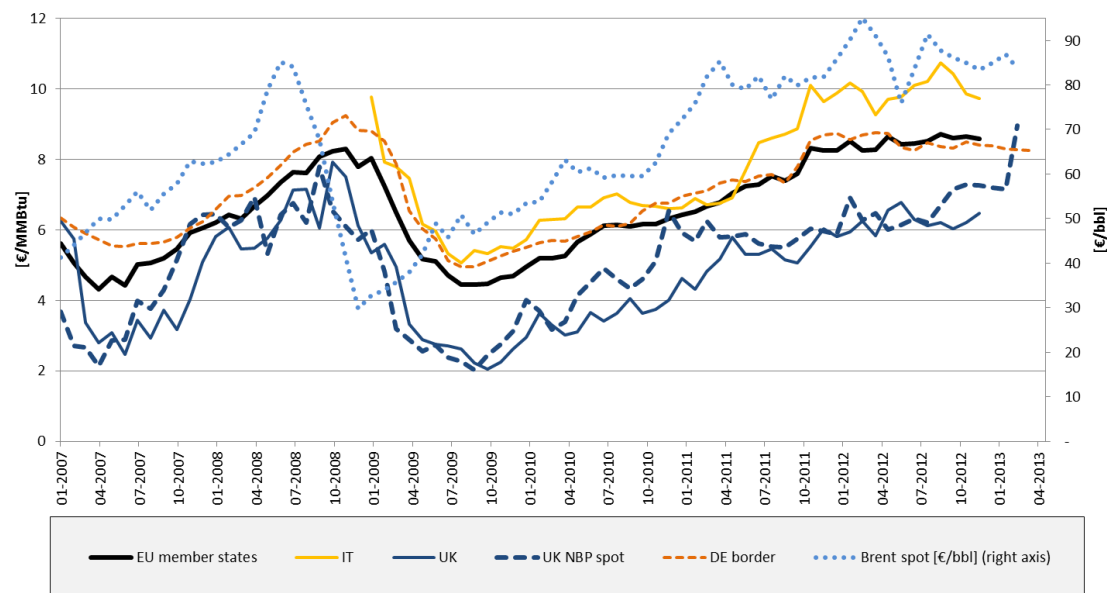
Both the NBP spot price and the average EU import price started their upward trend in mid-2008. However, the NBP price exhibited lower absolute prices in early 2007 and late 2008. It should be further noted that the NBP spot price was half the long-term-contract oil-linked price in 2009. In general, the average EU import price is higher than the UK NBP price during almost all of the period examined. The EU member states' import price presents a fairly steady increase from 2009 until 2013, while the NBP price increased until end-2010 and then remained relatively stable until mid-2012, after which it started to increase [53].

Figure 79. Natural gas import and spot prices in Europe, 2007 – 2013.



Source: European Parliament, Directorate General for Internal Policies

Figure 80. Natural gas import prices into European countries.



Source: European Parliament, Directorate General for Internal Policies

Figures 79 and 80 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 spot prices. Although it is difficult, at this stage, to predict market behaviour and its reflection on spot prices, once the 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.

10. CONCLUSIONS

1. 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 nine (9) such hubs are in operation and more are planned over the next one to two years.
2. Trading gas 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 hubs capable of serving the need of a wider region is fast gaining ground.

3. 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.
4. 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 sustainability by 2018-2020.
5. On the basis of presently contracted gas volumes to be transited through SE Europe by 2018-2019, it appears that market liquidity will substantially increase over the next few years with a parallel rise of gas trading opportunities
6. 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.

7. The background is already set for the planning and establishment of one or two gas trading hubs which will serve the needs of the broader SE European region enabling market participants in Greece, Bulgaria, Romania, Turkey and possibly Serbia, to participate in gas trading activities.
8. Already the TSOs of the countries in the region, Stock Exchanges, key market players and other stake holders are actively exploring the possibilities and prospects of establishing gas trading hubs.
9. The EU's role through its existing legislation and Directives is crucial towards the establishment of suitable conditions (i.e. balancing point and virtual trading point) in the various country members of the region, which will allow free and competitive gas trading.
10. In order for one or more regional gas trading hubs to be established market liquidity must increase considerably. For this to happen a series of key infrastructure projects (i.e. TAP-TANAP, IGB, South Kavala UGS, FSRUs) must be implemented, construction and operation of which must converge in 2018-2019.
11. From the analysis undertaken in the present study it is concluded that the process for the setting up and operation of at least two regional gas trading hubs has been set in motion. A road map for the establishment of these hubs is presented based on certain realistic assumptions.
12. The broad concept is for two regional gas hubs (possibly in Thessaloniki and Istanbul) to handle between them the anticipated gas volumes that will be generated following the opening up of the regional gas market. A lot will depend though, on the trading conditions that each Energy Exchange will offer in terms of accessibility, charges, speed of execution and clearance of orders and transparency. In a sense, having two regional exchanges will help considerably from a geographical aspect as the Istanbul one could take care of trades directed eastwards while the Thessaloniki one could deal with trades to the West and the North.
13. The financial implications arising from the operation of these two likely hubs are considerable both in terms of planned infrastructure investment (of the order of €6,0 billion) and in terms of traded volumes (in excess of €4,0 billion per year with conservative churn ratios and minimal quantities).
14. A SWOT analysis has revealed far more strengths and opportunities than weaknesses and threats.

The Proposed Conversion of the South Kavala Gas Field into Underground Gas Storage²²

Energean Oil & Gas is an independent E & P company focused on the Mediterranean and MENA region with operated assets in Greece and Egypt. It is the only Oil and Gas operator in Greece, and holds 100% of the two offshore oil & gas development licenses in the country – Prinos and South Kavala- with a 30 year production history and an excellent HSE track record. Energean Oil & Gas has a balanced portfolio of assets which includes:

- Production from Prinos&Prinos North fields 2,500 bbls/day- target to double by 2012
- Development of the 32 million barrel Epsilon Field -2012/13
- Existing oil & gas handling, processing and storage infrastructure in Kavala with 30,000 b/d capacity
- Exploration upside from a portfolio of assets in Greece & Egypt with more than 1 billion barrels of unrisksed HCIP.

Energean Oil & Gas workforce includes 300 dedicated oil and gas personnel in Athens, Kavala, Nicosia, Cairo and London which make a fully integrated oil and gas operating team lead by an experienced Board and Management team with proven track record in the international oil and gas sector. It should also be noted that Energean Oil and Gas was recently awarded (15/5/2014) by the Greek government, following competitive bidding, two new concession areas in Western Greece (Ioannina and Katakolo) and is uniquely positioned to participate in the upcoming international licensing rounds of offshore areas in the Ionian and South of Crete.

Energean Oil and Gas first proposed the conversion of the depleted South Kavala gas field into an underground gas storage project in Greece back in 2011.

The following key questions arise concerning the development of South Kavala as permanent gas storage to serve the needs of the Greek natural gas system:

- (a) Does Greece need Gas Storage?
- (b) Is the South Kavala project suitable?
- (c) Will the project happen?

Today the only existing gas storage capacity in Greece is to be found in the Revithoussa LNG Terminal off Megara some 40kms west of Piraeus. The main characteristics of this terminal are as follows:

Picture 38. Revithoussa LNG Terminal.



Source: Energean Oil & Gas

²² Based on a presentation by Energean Oil and Gas Company (www.energean.com) and supplementary information obtained by the IENE study team.

- Storage Capacity: 75,4 million Nm³ (130.000 m³ LNG)
- Gasification capacity: 12.5 millionNm³/ day
- Injection Rate to the tank: 104 million Nm³/ day
- Coverage of average gas demand: 8 days
- Coverage of peak demand: 5 days
- The main purpose of the Terminal is the import of gas; not an actual storage facility
- Gas-fired power plants are required to hold at least five days of fuel reserves: either diesel stored at the plant site, or equivalent gas reserves.

In addition to LNG storage capacity, EU Regulations clearly foresee the need for an underground Gas Storage for Greece and the region. More specifically:

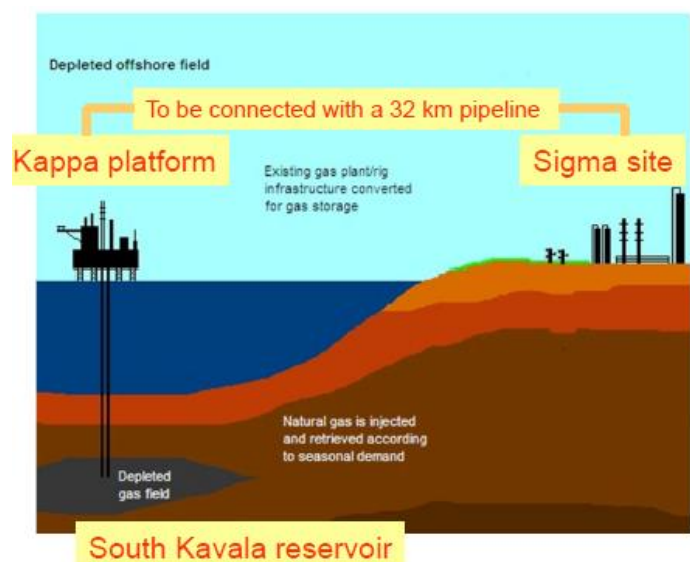
- New Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply makes specific reference to underground storage.
- They recommend the availability of underground storage in order to ensure gas supplies to vulnerable customers for at least 30 days under severe conditions.
- There is an obligation of Member States to implement the N-1 rule, by 2014, which requires the ability to cover the maximum daily consumption in the event of disruption of the single largest gas import infrastructure with possible occurrence in 20 years.
- Revythousa was not regarded as the “largest infrastructure” in 2014, and hence Greece cannot meet the N-1 rule without additional gas storage.
- South Kavala would also be considered for the consolidated implementation of Regulation 994/2010 in the broader region “Romania-Bulgaria-Greece”.
- A report by the Greek Ministry of Environment, Energy & Climate Change to the Parliament, in 2010, concluded that the Underground Gas Storage facility of South Kavala is absolutely necessary under the new market conditions.

Greece is located in the cross roads of three continents and can act as the gateway to the South Corridor, the markets of SE Europe and beyond. On the other hand, Kavala is ideally positioned to support major gas pipelines planned or act as an entry point for new offshore Gas projects in the East Med.

The question then arises if the South Kavala field is suitable for UGS. One should therefore consider the following:

Picture 39. South Kavala gas field.

- South Kavala is an almost depleted, offshore gas field producing since 1981 (85% RF; 52 m water depth; GIIP 0,95*10⁹ m³).
- The cavities of the storage consist of Turbiditic sandstone (Φ_{avg} 22%; k_{avg} 100mD; Evaporite top seal). There is no aquifer and there is dry gas (0,14 mol% CO₂) with P_{ini} 182 bar (current P_{res} 27 bar) and T_{res} 95°C. transportation network.



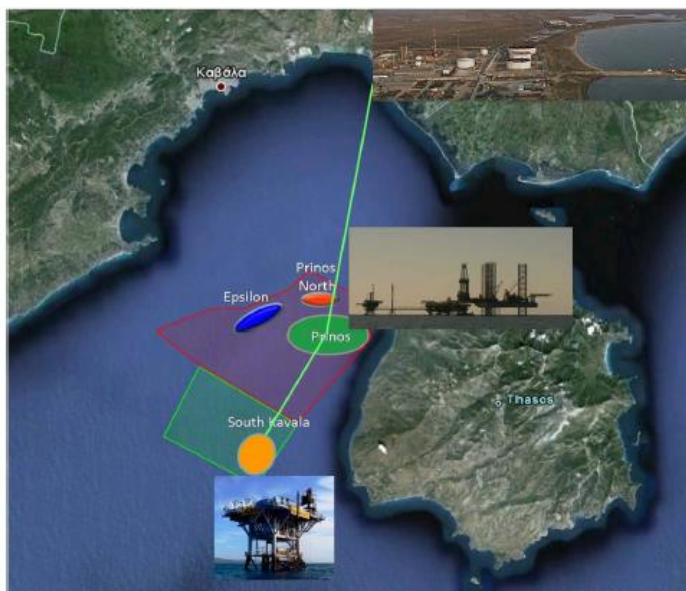
Source: Energean Oil & Gas

- The South Kavala depleted field is located in close proximity to the Greek gas.

Based on the above, South Kavala appears to be an ideal candidate for UGS.

Picture 40. South Kavala Underground Gas Storage – Project Characteristics.

Gas Initially In Place	1 BCM
Remaining Gas in reservoir	150 MCM
Working gas	530 x 2 MCM
Max Deliverability	9 Mcm/d
Max Injection	7,5 Mcm/d
Cycles per year	2
Max well-head pressure	180 barg
Number of wells	5
Gas pipeline diameter	30 inch



Source: Energean Oil & Gas

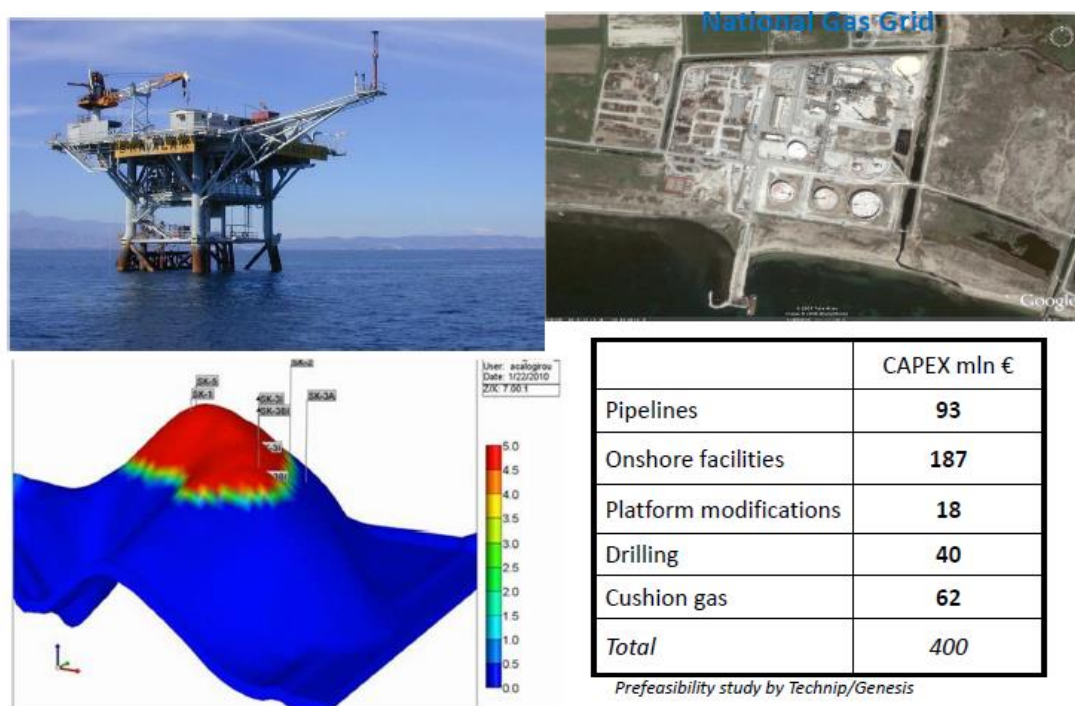
Once in operation the potential users of the Gas Storage capacity in South Kavala could include the following:

- Transmission System Operators for national and regional security of supply,
- Power Generators for cost reduction and enhancement of their security of supply and flexibility,
- Industrial users,
- Gas supply companies,
- Gas traders,
- Southern Gas Corridor project developers.

In view of the above the South Kavala UGS facility could provide a potential flexible entry point for East Med gas supplies through CNG/LNG projects into Europe. In this context, Energean Oil and Gas has proposed that part of the capacity to be booked for national security of supply purpose. Also, part of the TPA to be exempted for project sponsors to ensure bankability of the project and finally, part of the capacity to be offered through open season tender process to market participants.

Project Status

Picture 41. South Kavala infrastructure with associated project costs.



Source: Energean Oil & Gas

Today, Energean Oil and Gas SA is the operator of Prinos and South Kavala licenses (Law 2779/1999). The New Energy Law 4001/2011 (Article 93) provides that the holder of the petroleum license has a “priority right” for the conversion of an existing hydrocarbon development license into underground gas storage (“UGS”) license, as is the common practice in many countries (i.e. UK, France, Netherlands). Consequently, Energean Oil and Gas submitted to the Greek Energy Regulator RAE an application to convert its South Kavala development license into UGS license in July 2011. RAE concluded that a Common Ministerial Decision on the terms of the conversion of the license was required. The Government then appointed a Financial Advisor for this purpose. Meanwhile, the EU granted Energean, as sponsor of the project, TEN-E financing for the completion of technical and commercial studies. Following that a pre-feasibility study was conducted by Energean while a high degree of acceptance for the project was shown by the local community which endorsed it with great enthusiasm.

However, following ill advice from the Hellenic Republic Asset Development Fund - HRADF (ie. the privatization agency which was set up by the Troika in order to exploit state owned assets and contribute towards Greece’s debt reduction), Energean’s Oil and Gas operating license for South Kavala was revoked by the government in 2012 (effective in November 2014) and hence the company was unable to go ahead and implement its plans for a major investment, estimated at €400 million, to convert South Kavala into a

permanent underground storage facility. Ownership and exploitation rights for South Kavala were accordingly returned to the state as foreseen by law 2001/2011, and without the government examining at all Energean's Oil and Gas investment plans for South Kavala as it was clearly obliged to do, (again under law 2001/2011) prior to revoking its license. So far HRADF has shown no interest whatsoever in developing this project as it clearly lacks the technical and administrative capability and investment drive to organize an international tender (which by law is obliged to do).

In Brief

A number of questions naturally arise with regard to the South Kavala USG project and the government's poor handling of the matter so far:

- Does Greece Need Gas Storage?
 - ✓ Today, there is effectively no Gas Storage in the country
 - ✓ EU regulations require Greece to have more storage capacity
 - ✓ The market participants need more storage capacity
 - ✓ Competition in the market will be introduced
- Is South Kavala Suitable for a UGS project?
 - ✓ It is an ideal gas reservoir with a readily available operator that has a 30 year production history and excellent HSE track record
 - ✓ The existing offshore and onshore infrastructure with proximity to the national gas grid, as well as the planned regional gas pipeline network, make the South Kaval USG an ideal project to implement
 - ✓ Being the only depleted gas reservoir in Greece makes it unique in the region

As far as the project status is concerned the following summarize the present situation:

- The legal framework is in place mainly through energy law (2001/2011) and the existing licensing status of Energean Oil and Gas.
- There are strong project sponsors while the combination of the reservoir and local knowledge, technical and financial strength can ensure the seamless execution of the project.
- The Hellenic Republic Asset Development Fund (HRDAF) which now has sole responsibility of the project- and does not require any further approvals by the government-needs to go ahead and organize an international tender and invite bids for the award of the license to convert the South Kavala field into a permanent underground storage facility and operate it accordingly.
- Unfortunately, HRDAF has not provided any indication as to its intentions concerning a firm timetable for the project's implementation.

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