Gas Supply in SE Europe and the Key Role of LNG

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Final Report

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1. Introduction – Raison d' être

Natural gas is a relatively new fuel for the SE European region[1] while a number of countries, especially in the West Balkans, do not yet include gas in their energy balances or they are using only minimal quantities. In two key countries of the region, in terms of infrastructure and consumption, gas was introduced as late as 1996 in the case of Greece and in 1989 in the case of Turkey. But also in the case of the ex-COMECON countries in SE Europe, gas was not widely used, since priority was given to much cheaper and locally available lignite with Moscow preferring to sell most available gas quantities to Germany and other European countries in exchange of hard currency.

The same approach was more or less valid for ex-Yugoslavia where emphasis was placed in maximizing the use of indigenous resources, largely based on lignite and hydro, with Croatia providing limited supplies of oil and gas. Again, gas was a late-comer and arrived only when Russia decided to make Slovenia a key junction for shipping gas to Italy.

The present study covers primarily the gas demand and supply conditions which together with critical gas storage issues are examined on a global and regional basis. Special reference is made to LNG because of its growing importance for the safe operation of the gas networks of various countries and because of its potentially crucial role in market development and competition. In this light, all ongoing and planned gas interconnection projects are examined together with the major cross-country gas pipelines currently under construction or in a development phase.

In addition, a discussion is made on the possibility of establishing both national and regional gas trading hubs very much in line with similar gas hubs currently operating in several European countries. It is anticipated that the setting up of such a regional hub(s) will greatly facilitate gas trading and hence enhance regional market integration and competition, ultimately helping maintain prices at reasonable levels for benefit of the consumers.

The targets of the present study can be summarized as follows:

1. examine the past and present situation in the global gas market as well as in the gas markets of selected countries in Southeast Europe (i.e. Greece, Turkey, Bulgaria,

[1] The SE European region as defined by IENE comprises a group of 13 countries (i.e. Albania, Bosnia & Herzegovina, Bulgaria, Croatia, Cyprus, FYR of Macedonia, Greece, Kosovo, Montenegro, Romania, Serbia, Slovenia and Turkey) which have been chosen on the strength of geography but also on the basis of economic and political criteria. Turkey is a much larger country compared to any of the other states and its economy, because of its size and dynamism, affects to a large extent financial, trade and energy flows to the rest of SE Europe.

Romania, Serbia, Croatia and FYROM), but also in Italy and Ukraine, with specific reference to how all these markets are expected to be shaped over the next few years

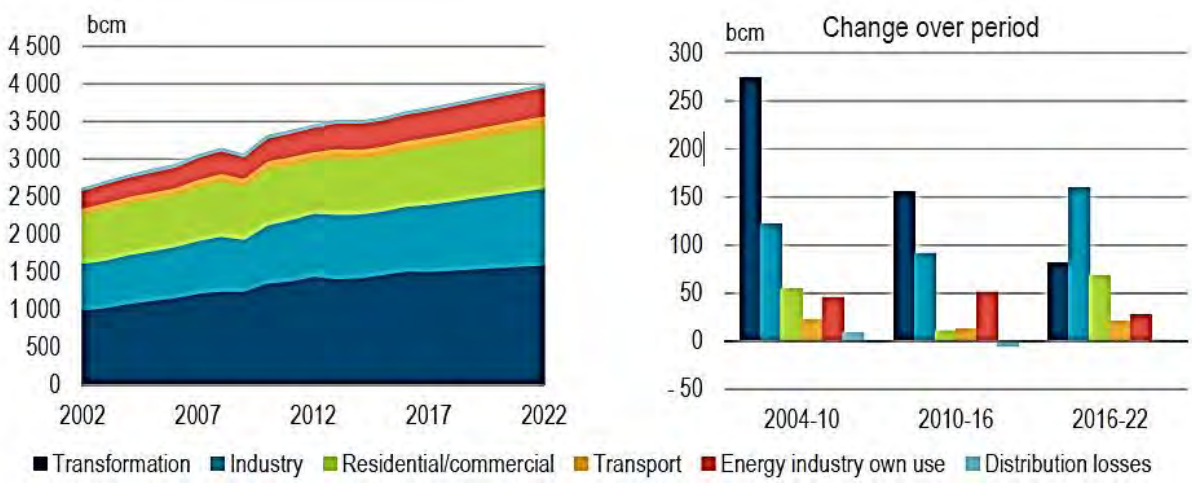
2. examine the past and present situation in the global LNG market as well as in the SE European region, with specific reference to how all these markets are expected to be shaped over the next few years
3. analyse all major existing and planned gas infrastructure projects in SE Europe (e.g. cross-border and national gas pipelines, gas storage facilities and LNG terminals)
4. analyse the geopolitical developments in the SEE region and how these are anticipated to impact the balance of regional gas markets
5. highlight the emergence of FSRU projects and their strategic role in enhancing regional energy security, with special reference to the Alexandroupolis FSRU project
6. examine the possibilities for the establishment of a gas trading hub in Greece and in the region
7. examine the existing and potential sources of funding for planned gas projects in SE Europe
8. present an overall assessment of the energy security dimension in SE Europe, energy policies and underline the strategic role of LNG with special reference to FSRU projects.

2. Global gas demand and supply overview

Gas Demand

As shown in Figure 1, global gas demand will reach 3,986 bcm by 2022, increasing annually by 1.6% on average over the forecast period, a bit faster than the 1.5% recorded over the prior six years. The demand increase by 10% will be equivalent to an incremental 357 bcm between 2016 and 2022, according to IEA's Gas Market Report 2017 (1).

Figure 1 – Global demand by sector, 2002-22



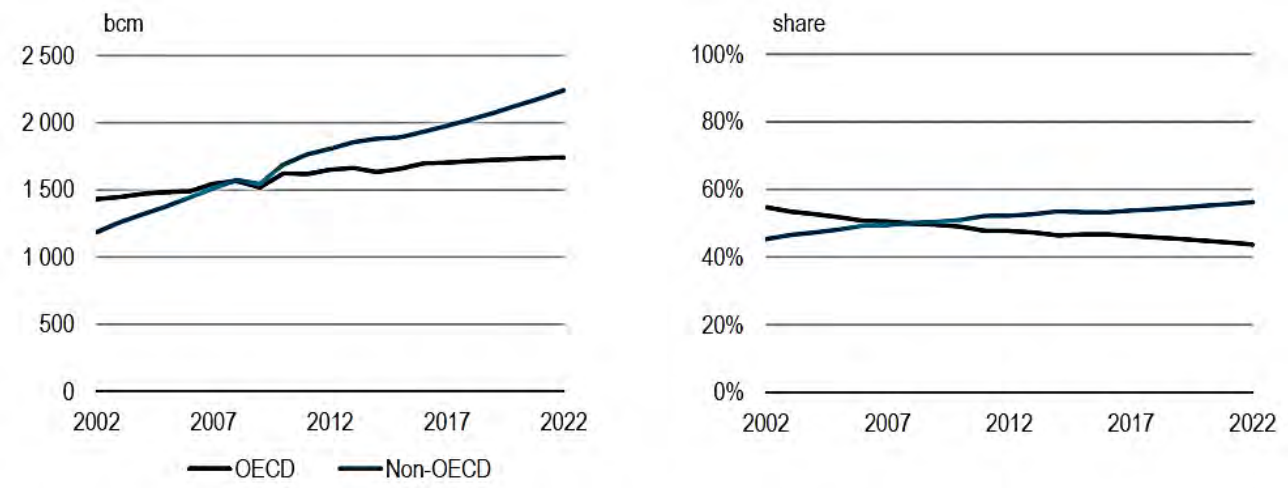
Source: IEA (2017a)

Gas demand growth in the power generation sector has slowed significantly. Over the past dozen years, global gas demand for power generation has been the main driver of global gas growth. This is no longer the case. Natural gas generation is projected to increase but at a lower growth rate thanks to more renewables and competition from energy efficiency. IEA's report expects additional demand for natural gas in power generation over the next six years to grow at about 1% per year, less than half the rate of growth of previous six-year period and much lower than the 4% recorded in the period 2004-10.

Instead, it is industrial demand that is actually expected to pick up in the next six-year period, with an average growth of 2.9% per year and accounting for almost 45% of the global incremental demand. The projected growth in industrial demand reflects expected increasing global economic activity especially in emerging markets and developing economies. Important drivers behind the growth are also the positive outlook for the petrochemical industry in regions such as North America and the Middle East and the need to boost fertiliser production, especially in highly populated countries such as India and Indonesia.

In 2016, the residential and commercial sector consumed around 750 bcm. At the end of the forecast period, this sector will have increased its consumption by around 65 bcm, growing modestly by an annual average of 1.5% and contributing around 20% to incremental demand growth worldwide. Around 40% of the total incremental growth in demand in the residential and commercial sector worldwide will occur in China due to government policy to promote the use of gas in this sector. The second-fastest-growing region is the Middle East, accounting for around 15% of the incremental demand. The modest growth is mainly caused by a declining trend in Europe due to efficiency in the residential sector. The transportation sector will grow at a high pace (around 2.6%), although volumes are not significant yet (140 bcm by 2022).

Figure 2 – Relative evolution of OECD and non-OECD demand, 2002-22



Source: IEA (2017a)

Nearly all the growth in gas demand occurs outside OECD countries. IEA's report expects non-OECD countries to account for around 90% of the growth in gas demand to 2022. As a consequence, non-OECD countries' share of the global gas consumption will grow to 56% from around 53% today. Demand in 2022 will amount to around 2,245 bcm per year. The usage of gas in OECD countries will stagnate, showing an increase of only 0.4% over the forecast period. By 2022, these countries will consume around 1,740 bcm.

Table 1 – Global demand by region, 2016-22

Region	2016*	2018	2020	2022	CAAGR 2016-22	Contribution to global growth
OECD Americas	973	991	1 012	1 028	0.9%	16%
OECD Europe	507	509	507	505	-0.1%	-1%
OECD Asia Oceania	218	213	211	206	-0.9%	-3%
China	205	245	292	339	8.7%	38%
Non-OECD Asia	312	330	352	375	3.1%	18%
FSU/non-OECD Europe	654	655	658	662	0.2%	2%
Middle East	471	495	517	542	2.4%	20%
Africa	127	137	146	153	3.1%	7%
Latin America	163	166	171	176	1.3%	4%
Total	**3 629**	**3 740**	**3 866**	**3 986**	**1.6%**	

Note: FSU = Former Soviet Union; CAAGR = compound average annual growth rate.

Source: IEA (2017a)

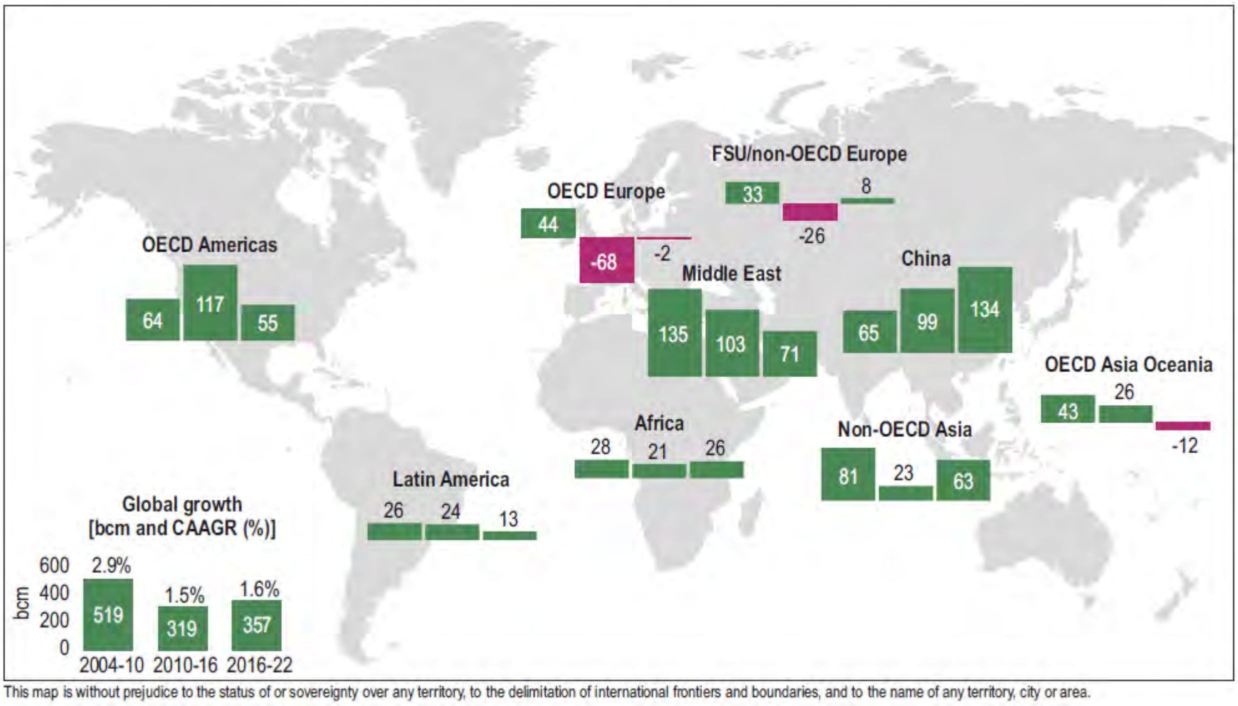
In the prior period, 2010-16, gas demand in the power sector in the US was the major driving force behind growth. As a relatively cheap and abundant fuel, gas has the potential to further boost industrial development in the US, in areas such as the chemical sector. The main factor pushing demand upwards in China is the policy of the central government to improve air quality, which is becoming critical considering the increasing urbanisation. In the FSU and non-OECD Europe region, demand will show a minor increase. For the next five years, gas demand for power generation in Russia is expected to decrease, with more efficient gas-fired power generation capacities being commissioned, a slight increase in nuclear power generation and moderate growth in Russian GDP.

The growth in gas demand in the Middle East will be driven by a fast-growing population and expanding energy-intensive industries such as the chemical, aluminium and steel sectors. The industrial demand will grow at an average of 2.7% per year over the forecast period. Furthermore, growth will be driven by new policies like those in Saudi Arabia, where the government wants to boost gas generation capacity with the aim of reducing the share of oil in the generation of power, thus keeping oil resources for export.

Demand in OECD Asia is projected to decline over the forecast period due to lower consumption in the power sectors in Japan and Korea. The decline in Japan will be caused by nuclear power capacity coming back on line, flat electricity demand and continued deployment of renewables. Korean demand remains uncertain: gas use in the power sector was expected to be reduced by the start-up of new nuclear and coal-fired generation.

However, Korea's new government targets a nuclear phase-out and curtailment of coal-fired power generation, which would lead to an increase in gas use.

Map 1 – Global demand growth by region, 2004-10, 2010-16 and 2016-22



Source: IEA (2017a)

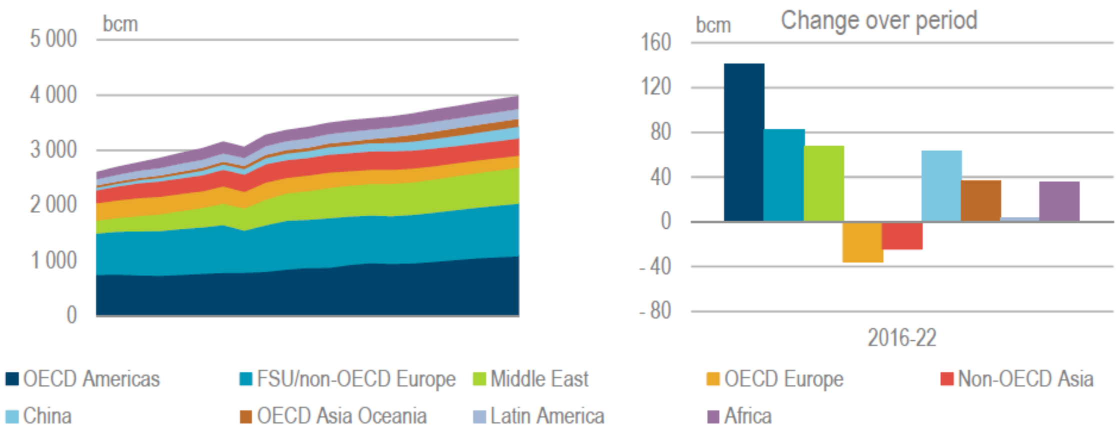
Africa's gas demand is projected to grow at an average of 3.1% from 2016-22, three-tenths of a percentage point lower than the growth forecast in last year's report for the period 2015-21. The deceleration is caused by a sharp economic slowdown in countries such as Nigeria and Algeria, as low oil and gas prices persisted in combination with difficult domestic political and economic conditions. Latin America will show a modest growth of 1.3% over the outlook period, reflecting the relatively weak economic performance of the continent and the limited space for growth for gas beside hydro and other renewables.

Gas Supply

Over the forecast period, global production will increase by 10%, going up from 3,615 bcm to 3,986 bcm by 2022. The United States will be the largest contributor to this incremental production, while relatively strong growth will also take place in the Middle East, China, Russia and Australia.

After 2016, the first year of production decline since the beginning of the shale gas revolution, natural gas production in the United States will rebound over the outlook period, demonstrating the remarkable adaptability and flexibility of the US gas industry in a relatively low-price environment. Due to the expected rebalancing of oil markets, US oil production will recover, leading to higher associated gas output. The extension of pipeline infrastructure in the Appalachian Basin will also be an important driver behind production growth, creating a larger transport capacity to bring additional quantities to the US Northeast/Canada, Midwest and Southeast markets. Liquefied natural gas (LNG) exports might drive production, too. Over the forecast period, production in the United States is estimated to grow at 2.9% per year, adding around 140 bcm to global production. By 2022, the United States will produce approximately 890 bcm, maintaining its position as the largest producer worldwide.

Figure 3 – Global gas production in 2002-22 and regional share in growth 2016-22



Note: OECD = Organisation for Economic Co-operation and Development; FSU = Former Soviet Union.

Source: IEA (2017a)

Over the forecast period, non-OECD countries will account for around 62% of global gas production. This forecast is only 2% below the share in the period 2010-16, showing a strong continuity in the contribution of non-OECD countries to global gas output. OECD countries will see a slight increase in their share of global production, mainly caused by the expected growth in the United States and Australia.

European gas production will continue to decline thanks to falling investments, a mature resource base and tighter restrictions on Groningen production in the Netherlands. Over the forecast period, OECD Asia Oceania will show a substantial increase in gas production from 2016 levels, around 40 bcm by 2022, driven by the start-up of three new LNG projects in Australia, as well as ramping up output from four recently completed projects.

Table 2 – Global gas supply by region, 2016-22

Region	2016*	2018	2020	2022	CAAGR 2016-22	Contribution to global growth
OECD Americas	958	1 000	1 060	1 099	2.3%	38%
OECD Europe	254	239	228	218	-2.5%	-10%
OECD Asia Oceania	107	134	142	144	5.1%	10%
China	137	159	181	200	6.6%	17%
Non-OECD Asia	336	323	308	312	-1.2%	-6%
FSU/non-OECD Europe	865	889	916	948	1.5%	22%
Middle East	583	598	623	651	1.8%	18%
Africa	202	223	232	237	2.7%	10%
Latin America	173	176	175	177	0.3%	1%
Total	**3 615**	**3 740**	**3 866**	**3 986**	**1.6%**	

Note: CAAGR = compound average annual growth rate.

Source: IEA (2017a)

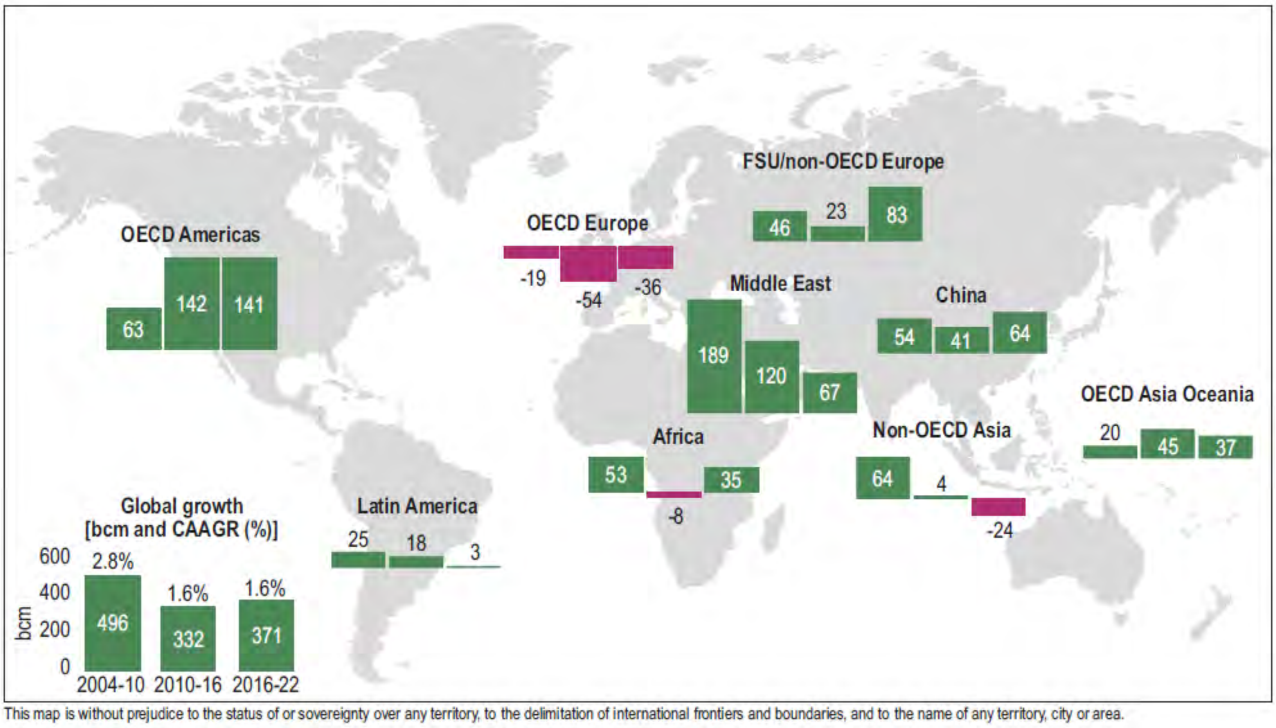
Chinese domestic gas production is projected to grow at an annual average of 6.6%, from 137 bcm in 2016 to 200 bcm at the end of the forecast period, roughly a half of a percentage point higher than last year's annual growth but below the expected pace set out in the 13th Five-Year Plan of the Chinese government.

Gas production in non-OECD Asia is forecast to decline at an annual average of 1.2% between 2016 and 2022, compared with an average yearly increase of 0.2% over the prior six years. The structural drop will be caused mainly by depletion of current gas fields and slow investment in the low gas price environment in countries such as India and Indonesia.

Production from FSU/non-OECD Europe is forecast to increase to around 950 bcm in 2022. The main reasons for this growth are the increasing exports to China from Turkmenistan, the Russian Federation (hereafter, "Russia"), Kazakhstan and Uzbekistan, the increasing exports to OECD Europe from Azerbaijan and the ramp-up of Yamal LNG in Russia.

In the Middle East, gas output is projected to grow annually by an average of 1.8% per year, up from around 585 bcm in 2016 to 650 bcm at the end of the outlook period. Iran, Qatar and Saudi Arabia will account for around 75% of the incremental gas production in the Middle East.

Map 2 – Global gas supply growth by region, 2004-10, 2010-16 and 2016-22



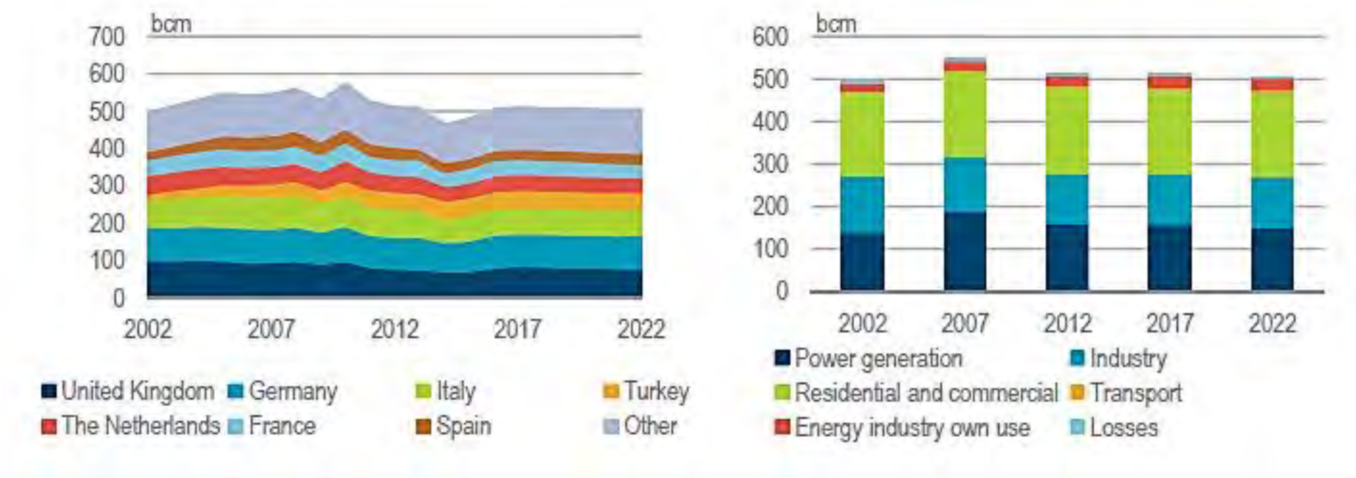
Source: IEA (2017a)

3. Gas demand for Europe and SE Europe and supply overview

Gas Demand

For the second year in a row, gas demand in OECD Europe has grown. After leaving the 2014 low of 465 bcm, demand climbed from 480 bcm in 2015 to 507 bcm in 2016. The demand increase in 2016 was driven for the most part by gas demand for power generation and to a lesser extent by an increase in residential gas demand due to colder weather compared with the warm winters of 2014 and 2015. Over the forecast period up to 2022, total gas demand is expected to remain flat.

Figure 4 – OECD Europe gas demand by country and sector, 2002-22



Source: IEA (2017a)

The main reason for the flat demand outlook is the expectation that a very large share of the potential increase of gas for power generation in OECD Europe already took place in 2016 and will decline slightly again towards 2022, being partly offset by a slight increase in industrial demand and residential demand returning to where it was during average temperatures.

As described in last year's IEA gas market report, the share of gas in the power generation mix is dependent on the power generation costs in comparison with other fuels. From 2012 to 2015, the gas price in Continental Europe was too high for gas to compete with coal on a marginal cost basis. However, in 2016, a lower gas price combined with a steep increase in coal prices allowed gas to compete with coal for power generation in some parts of OECD Europe. In the major power-producing countries – the United Kingdom, Germany, the Netherlands, France, Spain and Italy – gas demand for power generation increased significantly in the second half of 2016. In 2016, these interconnected markets experienced a drop in nuclear power while renewable generation and power demand stagnated. Gas, as the marginal power source at the time, filled that gap and at the same time replaced part of the coal-fired power generation.

Each country experienced its own market dynamic. In the United Kingdom, carbon pricing drove a coal-to-gas switch that resulted in the largest growth of gas for power in Europe, increasing by more than 8 bcm, equal to the big drop in gas for power the United Kingdom experienced in 2011-12. In Germany, gas-fired power generation increased more than the decline in coal-fired power generation and the decline in nuclear generation, while renewables generation and total power demand stagnated in 2016. In France, the loss of nuclear capacity as a result of reactor safety issues led to a moderate rise in gas-fired power generation. Another case is Italy, where both coal and predominantly gas increased as a response to higher power export demand.

In IEA's outlook, power demand in Continental Europe remains flat and renewable electricity production is expected to grow substantially more than the decline in European coal power generation and German nuclear output. Add to this the return of France's nuclear fleet to previous output levels, the IEA report forecasts a further decline of gas-fired power generation in continental Europe by 2022.

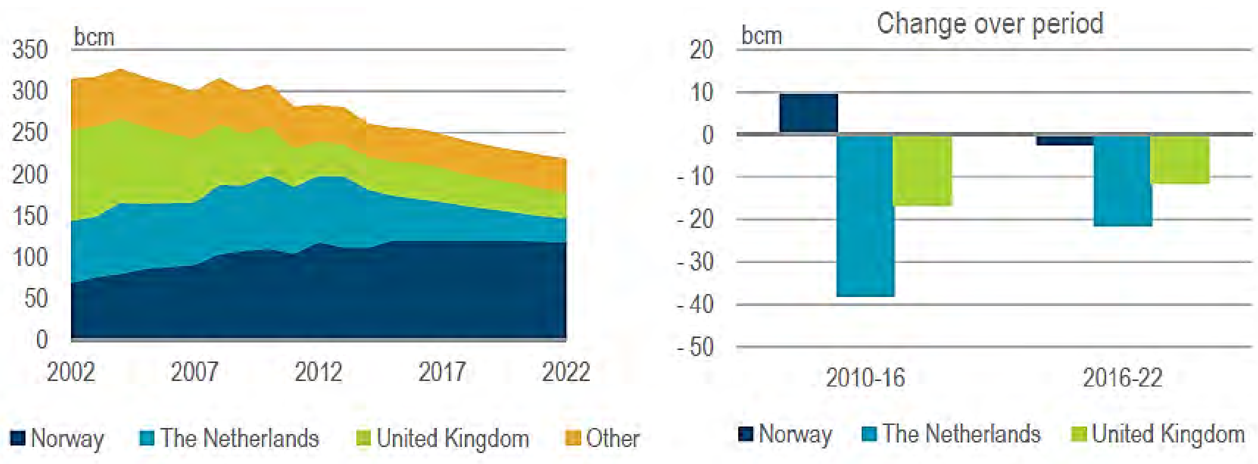
This decrease in gas demand for power generation by 2022 will be partly offset by slight increases in the residential and industry sectors. While temperature-driven residential demand varies from year to year, 2016 was still below average, leaving some room for growth. Industrial demand has decreased since 2013 and is expected to grow only marginally. In Europe, relatively low economic growth and stagnating industrial gas demand were observed over the period 2010-16. As GDP growth over the forecast period is expected to be higher than the average over 2010-16, a very small recovery in industrial gas demand is expected.

Gas Supply

OECD Europe gas production has been declining since 2004, reaching a record low of 254 bcm in 2016, approximately 2 bcm lower than the previous year. The 5% production increase in the United Kingdom and two years of high production in Norway did not offset the fast production decline from the small Dutch gas fields. Together with the Dutch Groningen production cap set for the next five years, production is expected to fall, with an average annual decline rate of -2.5%, reaching a production volume of around 220 bcm in 2022. Compared with last year's forecast, the projected production profile for the next three to four years is slightly more positive, as Norway and the United Kingdom are expected to perform better than anticipated earlier.

Production from the continental shelf of the Netherlands and the United Kingdom is expected to decline over the forecast period, although higher efficiency and major tax reductions in the United Kingdom resulted in positive impacts on performance in 2015 and 2016. Capital investments in the United Kingdom have declined for three years in a row, from nearly 15 billion British pounds (GBP) in 2014 to an expected GBP 6 billion in committed investments for 2017.

Figure 5 – OECD Europe gas supply by country, 2002-22



Source: IEA (2017a)

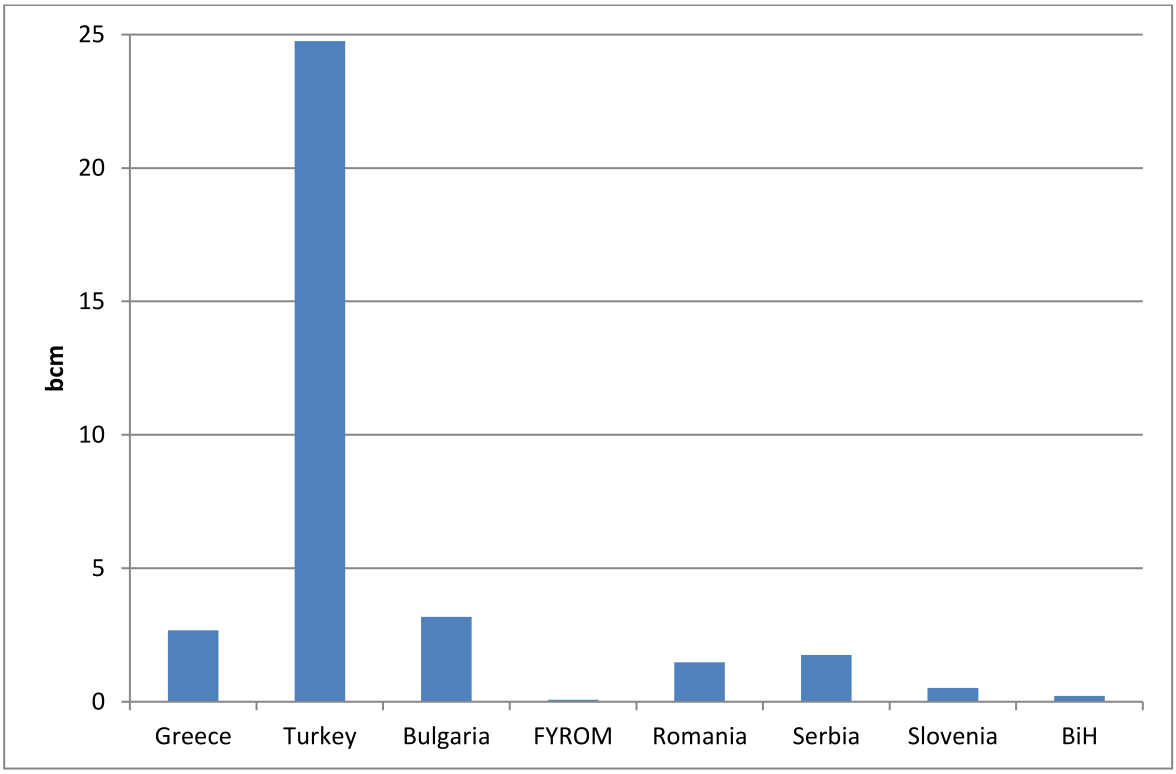
The case of SE Europe

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

Gas Demand and Supply

According to a recent study (2) prepared by the Oxford Institute for Energy Studies as well as IENE's "SE Europe Energy Outlook 2016/2017" study (3), SE Europe is not a homogenous region in terms of gas market maturity, infrastructures and gas interconnections. Greece, Croatia, Bulgaria, Romania, Serbia and Turkey have well-established gas markets, with supplies coming primarily through imports from Russia and, in the case of Turkey, from Iran and Azerbaijan. Greece and Turkey, which have well developed LNG import and storage terminals, also import from Algeria, Nigeria, Qatar and other LNG spot markets. Greece also imports gas from Turkey gas system, in the form of 'Turkish gas basket'. Two countries have a significant proportion of their demand met from domestic supplies (Croatia, Romania) and three others cover small percentage shares from domestic gas (Bulgaria, Serbia, Turkey). On the other hand, some other countries of the region completely lack gas infrastructure such as Albania, Kosovo, Montenegro and Cyprus. Figure 6 depicts Russian gas supplies to selected SE European countries in 2016.

Figure 6 – Russian gas supplies to selected SE European countries, 2016



Note: Albania, Montenegro, Kosovo and Cyprus do not produce, import or consume natural gas.

Source: Gazprom[2]

Due to the region's gas infrastructure deficit, natural gas market development is much lower than in other European countries. From Map 3, it is clear that no gas infrastructure exists for the biggest part of the West Balkan region. At the same time, the rate of natural gas penetration in the region's energy mix is very slow. For instance, the gasification rate in Bulgaria is less than 2% in households while average rates in European Union lie between 27%-50%. Many countries in SE Europe are dependent on a single supplier for most or all of their natural gas. Some countries, such as FYROM, Bosnia and Herzegovina and Greece, are

[2] http://www.gazpromexport.ru/en/statistics/

100% dependent from imports, while the rest of the countries, with the exception of Croatia and Romania, depend on imports for more than 80% of their demand.

Map 3 – The Gas System Network in SE Europe

Source: ENTSOG[3]

Currently, the region can cover around 37% of its gas consumption through indigenous production, while the rest is imported almost entirely from Russia. Due to this single supplier dependence, the countries of the region consume the most expensive natural gas in Europe.

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[3] https://www.entsog.eu/public/uploads/files/maps/systemdevelopment/ENTSOG-GIE_SYSDEV_MAP2016-2017.pdf

High natural gas import prices also hinder the development of natural gas markets, forcing them to use cheaper carbon intensive fuels.

However, natural gas is gaining ground in SE Europe as a fuel of choice with most countries importing increasingly more quantities, mainly from Russia but also, in the case of Turkey from Iran and Azerbaijan, and also through LNG. LNG is expected to become an important player in the market, as there are plans for new LNG import terminals in the region. Already an FSRU unit is planned to be based offshore in 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 started in 2015, will be connected to Greece through the Trans-Adriatic Pipeline (TAP) pipeline. In addition to Azeri gas, TAP could also be used to transport North African gas to Southern Europe and Turkey via reverse flow. Plans are also in place for gas transit between Greece and Bulgaria and Bulgaria to Turkey via new interconnector pipelines.

Beyond the large regional gas import projects requiring major transmission lines transiting gas to one or more countries, there is a clear need for investment in cross-border transmission pipelines, relief of transmission bottlenecks, new transmission network connections in SEE countries and for increased seasonal storage in order to meet peak (winter) demand.

Europe also sees an important opportunity in meeting part of its energy needs by developing the Southern gas corridor, at the core of which are gas supplies from the Caspian area (mainly from Azerbaijan but also in future from Turkmenistan, Kazakhstan and Iran) and possibly from the Middle East (Iraq).

Furthermore, the need of the region to improve its supply security, which is heavily dependent on pipe-gas from Russia, allows even more room for new players to enter this market. Regarding the Italian market, even though it is currently oversupplied, there is a strong need for further diversification and the promotion of strong gas to gas competition. As a result, Italy and the SE European region remain an attractive market with room for new supply sources. A brief analysis on past, present and future gas supply and demand overview is presented below for selected SE European countries.

(a) Turkey

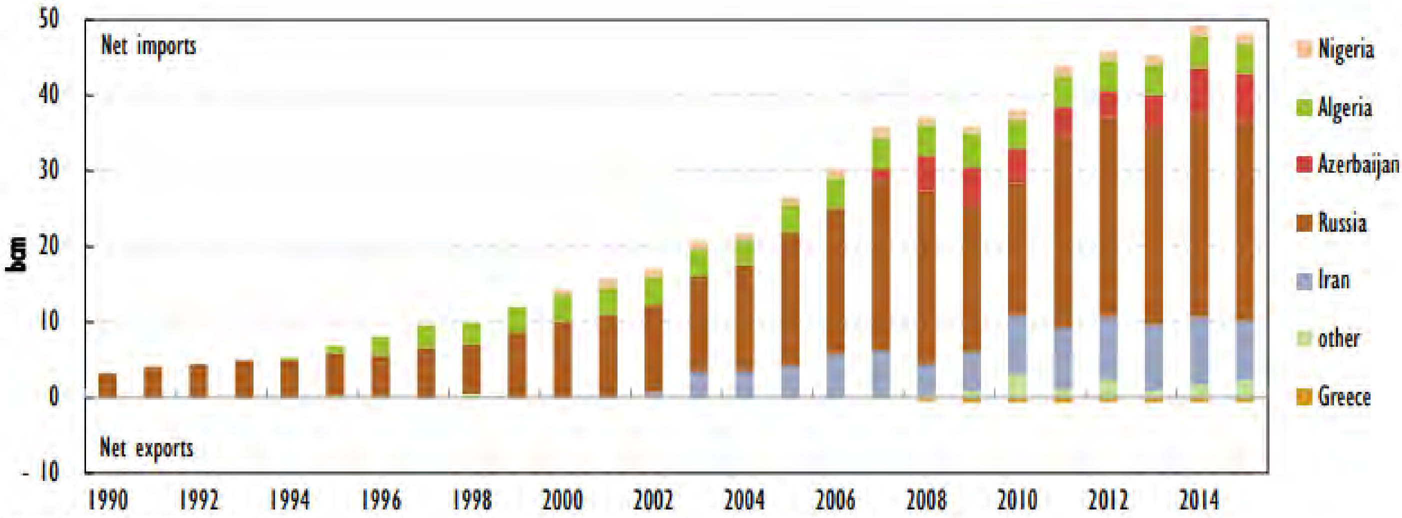
Gas Demand and Supply

According to the International Energy Agency's (IEA) 2016 Energy Review of Turkey (4), natural gas supply amounted to 39.2 million tonnes of oil equivalent (Mtoe) or 47.6 bcm in 2015. Supply is 2.4% lower than in the high gas demand year of 2014, but 35.7% higher than in 2009. Gas supply has been growing rapidly for decades since its first use in 1982. Natural gas is the main fuel in Turkey, with 30.2% of total TPES (the share of oil being 30.1%) and 38.6% of electricity generation in 2015. Natural gas demand (or total supply) amounted to 40.2 Mtoe or 48.7 bcm in 2014. Since gas was introduced in Turkey in 1982, demand had been on a steep-growing path until 2009, when it declined by 4.2% for the first time in 27 years. Demand recovered quickly by 8.6% in 2010, followed by a surge of 17.2% in 2011 and slower growth of around 1% in 2012-13, followed by a 6.1% rebound in 2014.

Based on IEA's data, indigenous natural gas production has seen a sharp decline, down from 1.017 bcm in 2008, to 0.684 bcm in 2009 and 0.4 bcm in 2015, representing less than 1% of domestic gas demand. Most of the natural gas is produced by the incumbent gas producer TPAO in the Black Sea offshore shallow waters. Turkey's remaining gas reserves are small with a total of 5.4 bcm in 2013. The government estimates that around 551 bcm of recoverable shale gas potential is available in Turkey, notably, in the south-east, the Anatolian Basin and the Diyarbakir Basin (Dadas formation) and, in the north-west, the Thrace Basin (Hamitabat formation), and in the Siva and Salt Lake Basins. Deep water exploration activities in the Black Sea have been ongoing since the 1970s by the international oil company majors. TPAO and Shell have been investing in exploration since February 2013 and the ISTRANCA-1 offshore oil well was tested for natural gas. Since November 2011, TPAO and Shell have been conducting exploratory drilling in the Turkish parts of the Mediterranean Sea. However, gas reserves remain underexplored. There are expectations that the new Petroleum Law of 2013 and its new licensing regime will stimulate exploration. Companies began exploratory hydraulic fracturing in the promising Dadas shale formation in the Diyarbakir region in south-east Turkey in 2013. Operations have been interrupted following terrorist attacks in the region.

Total imports in 2015 were 48.2 bcm, originating mostly from Russia (55.1% of the total), Iran (16.2%), Azerbaijan (12.3%), Algeria (8.1%), Nigeria (2.9%) and others. Pipeline gas is dominant in the import structure as liquefied natural gas (LNG) has only played a small role so far. Two LNG receiving terminals are in operation. Turkey received gas from five countries under long-term contracts and LNG supplies from the global spot market. By volume, Russian, Azeri and Iranian gas supplies have been on an upward trend since 2007. Turkey exports some natural gas to Greece, from 0.4 bcm in 2008 to 0.6 bcm in 2015 (IEA, 2016).

Figure 7 – Turkey's natural gas net trade by country, 1990-2015



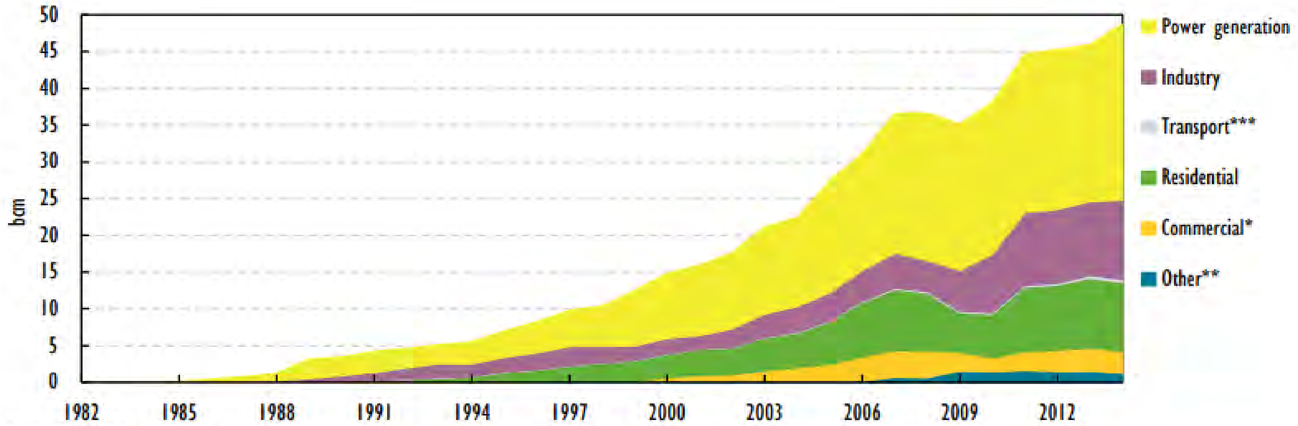
Note: *Other* includes spot LNG.

Source: IEA (2016b) (5)

Gas is mainly used in the power generation sector which was the largest natural gas consumer in Turkey, with a share of 49.1% in 2014. Looking at the trends over the years, however, industry, which accounts for 22%, is the fastest-growing consuming sector. Its share in total demand has grown from 15.4% in 2004, while the power generation share has fallen from 54.2% in 2004 and 60% in 2007. Demand from industry was 211.1% higher in 2014 than in 2004, while demand from power generation was 96.9% higher. Gas use in refining has increased sevenfold.

Households consumed 19.1% of natural gas in 2014, followed by commercial and other services (6.3%), refining and energy own-use (2.5%) and transport (0.9%). Demand from households and commercial services has almost doubled compared to 2004, rising from 6.6 Mtoe to 12.4 Mtoe, following the large-scale gasification of the country. Demand from transport has increased, starting at very low levels, growing its share fourfold from 0.6% to 0.9% during 2004 to 2014.

Figure 8 – Turkey's natural gas demand by sector, 1973-2014



Note: TPES by consuming sector.

* *Commercial* includes commercial and public services, agriculture/fishing and forestry.

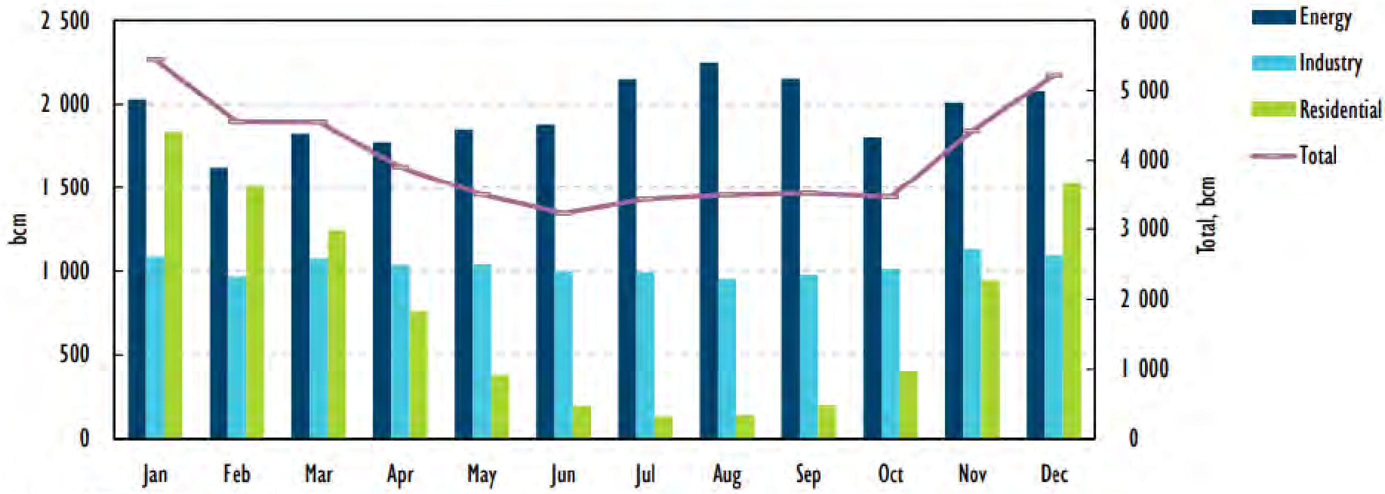
** *Other* includes LNG plants, other refining and energy own-use.

***negligible

Source: IEA (2016b)

The IEA expects a moderate growth in Turkey's gas demand as gasification of the distribution sector is almost completed. Next to the steady use of natural gas in the heating and industry sectors, future growth in the power sector will depend on the pace of renewable energy deployment, coal development and electricity demand growth. Coal to gas competition will be strong in the wholesale market in the absence of a carbon price or new environmental restrictions in Turkey, which gives coal an advantage over gas use in power generation.

Figure 9 – Turkey's natural gas demand seasonality, 2014



Source: MENR data provided 2014.

Source: IEA (2016b)

Table 3 illustrates Turkey's gas demand and supply data in 2015, based on data released by the Eurostat (6).

Table 3 – Natural gas demand and supply in Turkey, 2015

bcm	Gas
Primary production	**0.37**
Imports	**47.47**
Exports	**0.61**
Gross inland consumption (Natural gas)	**46.88**
Final energy consumption (Natural gas) by selected sectors:	**25.4**
-Industry	10.97
-Transport	0.42
-Residential	10.78

Sources: Eurostat (2017), IENE

Turkey's Gas Outlook

In 2016, gas demand in Turkey was approx. 46 bcm/year of which about 98% is imported. Projections concerning natural gas demand growth in Turkey vary significantly, with estimates for 2030 ranging from 60 to 70 bcm/year[4].

(b) Bulgaria

Gas Demand and Supply

Natural gas had an almost constant share of 14% in gross inland consumption during 2010-2015. About 40% of the natural gas in the country is used for electricity and heat generation. The non-energy use of natural gas in chemical industry accounted to 8-9% of gross inland consumption of natural gas, based on IENE's "SE Europe Energy Outlook 2016/2017" data. Natural gas contributed 2,595 ktoe[5] or 3.09 bcm in Bulgaria's 2015 gross inland consumption, increased by 9.82%, compared to the previous year.

Since 2010 and up to 2015, final energy consumption in Bulgaria increased due to higher industrial and transport needs. Only 4% of the natural gas is consumed by households.

Bulgaria has been producing natural gas from its continental shelf in the Black Sea since 2001. The increase of local production in 2011 and 2012 follows the development of new fields in Kaliakra and Kavarna. A small part (8%) of the inland consumption of natural gas is

[4] Oxford Institute for Energy Studies, Turkey's gas demand decline: reasons and consequences, 2017

[5] 1 mtoe=1.19 bcm

covered from local sources. The country relies mostly on natural gas imports to meet its domestic demand. Bulgaria's primary gas production stood at 85 ktoe or 0.1 bcm in 2015, recording a fall of 46.5%, compared to 2014 level.

Russia is the sole gas exporter to the country. Bulgaria also acts as a transit route for Russian gas destined for Turkey, Greece and FYR of Macedonia. Bulgaria's net gas imports increased slightly during 2010-2015; from 2,131 ktoe or 2.54 bcm in 2010 to 2,517 ktoe or 3 bcm in 2015. The gas imports are based on long term "take-or-pay" contracts between Bulgargaz (Bulgaria) and RAO Gazprom (Russia).

Table 4 – Natural gas demand and supply in Bulgaria, 2015

bcm	Gas
Primary production	**0.1**
Imports	**3.0**
Gross inland consumption (Natural gas)	**3.09**
Final energy consumption (Natural gas) by selected sectors:	**1.56**
-Industry	1.09
-Transport	0.28
-Residential	0.06

Sources: Eurostat (2017), IENE

Bulgaria's Gas Outlook

Bulgaria's gas consumption was 2.9 bcm in 2016 and is expected to rise rapidly over the next 10 years. Bulgartransgaz EAD, Bulgaria's TSO, estimates that natural gas demand in the country in 2017 will be 3.1 bcm and will gradually increase to 4.3 bcm/year by 2025, on the basis of sustainable economic growth of GDP - between 2 and 3% annually[6]. Natural gas imports in the country, exclusively from Russia, currently cover 97% of the domestic demand but Bulgartransgaz, in its Ten-Year Network Development Plan, Bulgartransgaz EAD anticipates that the significant increase in natural gas demand over the following years, will be met by alternative routes and sources of supply.

[6] 2016 - 2025 Ten-Year Network Development Plan of Bulgartransgaz EAD

(c) Romania

Gas Demand and Supply

Natural gas is the most important form of energy in Romania's final consumption structure. In 2015, gas accounted for 29% of the total energy demand, followed by oil products with 26%, renewable energy sources (including hydro) with 19%, coal with 17% and nuclear energy with 9%. Gas consumption is almost equally divided between the domestic and industrial sectors – in the latter gas is used primarily in the production of electricity and as raw material in petro chemistry.

The draft of the Energy Strategy 2016-2030, with an Outlook to 2050 (7), confers natural gas a prime role in the coming decades as well. In 2030, according to the projection made using the PRIMES model[7], gas will account for 26% of final energy demand which, despite a slight decrease compared to 2015, will still mean it is first. The relative decrease of 3% will be found in the increase of the RES share, which will reach 22%.

By 2030, about 1800 MW of gas-powered generation capacity will have to be replaced, in order for the gas-based capacity pool to maintain its current size.

Since 2005 up to 2015, Romania's net gas imports were constantly decreasing; from 4,190 ktoe or 4.99 bcm in 2005 to 161 ktoe or 0.19 bcm in 2015. 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 although imports from Russia are recently declining.

[7] The PRIMES model was also used in the preparation of IENE's "SE Europe Energy Outlook 2016/2017" study, with the valuable contribution of Professor Pantelis Capros.

Table 5 – Natural gas demand and supply in Romania, 2015

bcm	Gas
Primary production	**10.46**
Imports	**0.19**
Gross inland consumption (Natural gas)	**10.62**
Final energy consumption (Natural gas) by selected sectors:	**6.51**
-Industry	2.86
-Transport	0
-Residential	2.67

Sources: Eurostat (2017), IENE

Romania's Gas Outlook

In 2015, Romania's gas consumption was 11.6 bcm of which 97.6% was accounted for domestic production and 2.4% for imports (0.3 bcm)[8]. In line with ENTSO-G estimates, demand is estimated to remain relatively stable over the following years and could reach 12.2 bcm by 2020[9,10].

(d) Serbia

Gas Demand and Supply

Natural gas consumption in Serbia is largely based on imports from Russia (Gazprom – some 77%) and partially from domestic gas fields, located in the province of Vojvodina (Petroleum Industry of Serbia - some 23%). Natural gas exploration and production in Serbia is performed solely by the Petroleum Industry of Serbia (NIS).

In terms of final energy consumption, the largest part of the natural gas in 2015 was consumed by households (35%), followed by industry (28%) and agriculture and transport (25%). The share of natural gas in Serbia's primary energy production was 4.3% in 2015 and stood at 456 ktoe or 0.54 bcm, increased slightly from 444 ktoe or 0.53 bcm in 2014.

[8] Romania's Regulatory Authority for Energy (ANRE), National Report 2015

[9] ENTSO-G Ten Year Development Plan (TYNDP)

[10] OMV Petrom Q1/2017 Results

Since 2005 up to 2014, Serbia's net gas imports were constantly decreasing; from 1,718 ktoe or 2.05 bcm in 2005 to 1,111 ktoe or 1.32 bcm in 2014 and only in 2015, an increase was recorded at 1,386 ktoe or 1.65 bcm. Most of natural gas quantities are provided through imports from Russia based on long-term contracts, while the minority of gas quantities are imported based on other contracts (from Kazakhstan).

Table 6 – Natural gas demand and supply in Serbia, 2015

bcm	**Gas**
Primary production	**0.54**
Imports	**1,65**
Gross inland consumption (Natural gas)	**2.08**
Final energy consumption (Natural gas) by selected sectors:	**0.96**
-Industry	0.59
-Transport	0.01
-Residential	0.18

Sources: Eurostat (2017), IENE

Serbia's Gas Outlook

Currently, natural gas demand in Serbia is approx. 2.0 bcm/year of which 85% is imported from Russia and is estimated to reach 2.3 bcm/ year by 2020[11].

(e) Croatia

Gas Demand and Supply

Croatia's gas share in gross inland consumption in 2015 was 24.4%, almost at the same levels of 2014. In terms of final energy consumption, the largest part of the natural gas in 2015 was consumed by households (46%) and industry (35%). The share of natural gas in Croatia's primary energy production was 33.5% in 2015 and stood at 1,471 ktoe or 1.75 bcm, increased slightly from 1,444 ktoe or 1.72 bcm in 2014. Gas production in Croatia is likely to peak over the next five years, thus managing to cover the major proportion of the country's gas needs. Natural gas is produced in Croatia from 16 onshore and 9 offshore gas fields.

[11] Srbijagas, Development plan of the gas transportation system 2017-2026

Since 2005 up to 2015, Croatia's net gas imports remained almost at the same levels; from 562 ktoe or 0.67 bcm in 2005 to 564 ktoe or 0.68 bcm in 2015. Croatia's gas imports come from various countries. All imported gas is acquired in the open gas market. Croatia does not have any long term gas import contracts.

Table 7 – Natural gas demand and supply in Croatia, 2015

bcm	Gas
Primary production	**1.75**
Imports	**1.03**
Gross inland consumption (Natural gas)	**2.48**
Final energy consumption (Natural gas) by selected sectors:	**1.16**
-Industry	0.41
-Transport	0
-Residential	0.53

Sources: Eurostat (2017), IENE

Croatia's Gas Outlook

In Croatia, gas consumption stood at 2.7 bcm in 2016 and it is expected to increase by about 26% over 2017-2026; from 2.7 bcm in 2017 to 3.4 bcm in 2026, according to the Ten-Year Development Plan of Croatia's gas TSO Plinacro. This will lead to an increasing gas import requirement over the decade, with imports projected to rise from an estimate of fewer than 1.3 bcm in 2017 to 2.4 bcm in 2026. The power sector has increased its reliance on natural gas as a fuel for generation, with this trend expected to continue over the coming decade. There has also been a steady increase in the use of liquefied petroleum gas as a fuel for the transport sector.

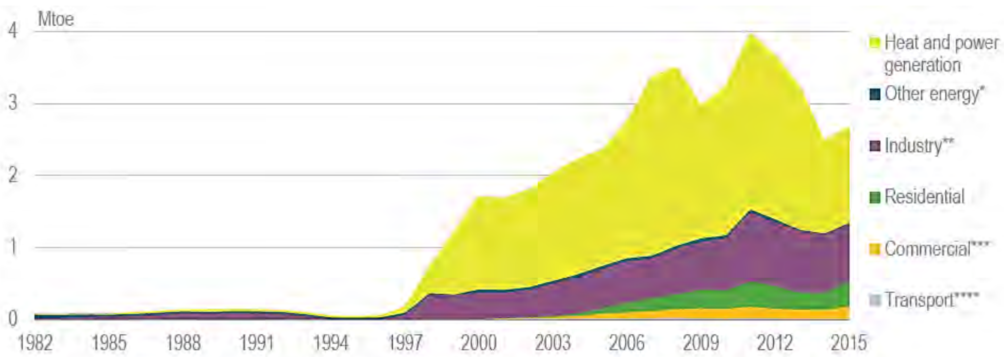
(f) Greece

Gas Demand and Supply

Gas was originally introduced into the country's fuel mix in the final quarter of 1996 and has to compete against lignite and fuel oil in its primary applications. Greece's natural gas production was 0.009 bcm in 2016, which is negligibly small compared to the total consumption of 4.1 bcm. The country is thus dependent on imports, of which Russia supplied 65% in 2016. Other large gas suppliers are Algeria, supplying LNG that covered 17% of total gas imports, and Turkey, accounting for 16% of Greece's total imports in 2016.

Natural gas consumption increased rapidly from insignificant levels in 1997 to a peak of 4.0 Mtoe or 4.76 bcm in 2011. After falling by over one-third in three years from 2011 due to the economic crisis, gas consumption recovered to 3.5 Mtoe or 4.1 bcm in 2016 from 2.7 Mtoe or 3.2 bcm in 2015. Power generation is the largest gas-consuming sector, accounting for half of the total gas consumption in 2015. This share has fallen from levels of around 70% a decade earlier. The decline in natural gas consumption is mainly due to reduced gas power generation, which fell by over half from a peak at 13.9 TWh in 2011 to 6.8 TWh in 2014, but increased to 9.1 TWh in 2015, representing 18% of the total power generation. The fall in total electricity generation (12% from 2011 to 2015) and the growth in renewable energy sources (81% from 2011 to 2015), which have replaced natural gas in the power mix, have resulted in a reduction in gas power generation. More information about Greece's gas demand and supply is shown in Figure 2 in Box 1.

Figure 10 – Greece's natural gas consumption by sector, 1982-2015



* *Other energy* includes petroleum refineries and energy own use.

** *Industry* includes non-energy use.

*** *Commercial* includes commercial and public services, agriculture, fishing, and forestry.

**** Negligible.

Notes: Natural gas in TPES by consuming sector. Consumption data per sector are available until 2015. Total gas consumption increased to 3.5 Mtoe in 2016.

Source: IEA

Table 8 – Natural gas demand and supply in Greece, 2016

bcm	Gas
Production	0.009
Net Imports	4.1
Consumption	4.1

Sources: IEA and IENE

Greece's Gas Outlook

In 2016, gas consumption in Greece amounted to 4.1 bcm, while demand for the full year of 2017 is projected at 4.9 bcm. This increase is attributed to the rising use of gas as a fuel for power generation for the whole year as well as the enhanced penetration of the distribution network in the domestic sector.

To project the gas demand for the period 2018-2027, the 2017 forecasted consumption was used as a basis and incorporated the following projections:

- Gas consumption for power generation is projected to increase in accordance with the increase of electricity demand. More specifically, the 10-year Development Plan[12] of ADMIE was incorporated in the analysis, which shows an increase in electricity demand from 52.6 TWh in 2017 to 61.8 TWh in 2027.

  The company has also applied the same annual increase on the natural gas consumption for power generation. Thus, gas consumption for power generation is estimated to reach 3.8 bcm in 2027 from 3.2 bcm in 2017 (a total increase of 0.6 bcm).

  It has to be noted that the above projections could be considered as conservative, since they have as a starting point the gas consumption for power generation of 3.2 bcm for 2017, which incorporates an average yearly CO_2 of 5.96 €/tn, while currently CO_2 is traded at 7.55 €/tn[13].

  If we also take into consideration the Paris agreement, CO_2 prices could reach the range of 30 €/tn due to the anticipation of deeper emissions cuts in order to reach the new aim of keeping temperature rise "well below 2°C" with efforts to pursue 1.5°C by 2100". This

[12] April 2017
[13] http://data1.lagie.gr/pls/apex/f?p=103:1:0::NO, 2017-11

will have a detrimental effect in the competitiveness of lignite plants against the natural gas ones.

- The projections for the customers connected to the distribution network, as depicted on RAE's decisions[14] for the Distribution Tariffs of 2017-2021 for EDA Attiki, EDA Thessaloniki-Thessaly and DEDA.

  For the years 2022-2028, the same annual increase with the period 2020-2021 was taken into account. It is worth noting that the above projections could be considered as conservative, since DEDA foresees that the gas distribution network will expand by 2023 to 18 cities in the prefectures of Central Greece, Central Macedonia and Eastern Macedonia-Thrace, leading to more than 100,000 residential and 11,000 commercial new connections.

- In terms of the gas projections for the small-scale LNG/CNG projects, which give access to gas to remote areas, the projections of DESFA were used as depicted in the Development Study 2018-2027.

  To this direction, DEPA recently signed a Memorandum of Understanding with Greece's Public Power Corporation (PPC) to supply gas in liquefied and/or compressed form, to non-interconnected islands and other remote regions, as an alternative fuel for power generation

Table 9 summarizes the gas consumption projections in Greece for the period 2018-2027. By 2023, the total gas consumption is estimated at 5.7 bcm, reaching 6.3 bcm by 2027.

[14] RAE's decisions 345/2016, 346/2016, 347/2016 and 348/2016

Table 9 – Gas consumption projections for the period 2018-2027

Gas consumption (in mil. Nm3/yr)	Additional volumes from gas consumption from power generation	Additional volumes per year from customers connected in the Distribution System	Additional volumes per year from small scale LNG/CNG	Total
2017				4,937
2018	69	49	0	5,054
2019	60	59	1	5,174
2020	147	59	1	5,382
2021	35	63	16	5,496
2022	22	63	11	5,592
2023	23	63	24	5,701
2024	22	63	29	5,815
2025	136	63	11	6,025
2026	26	63	29	6,143
2027	24	63	29	6,260

***Sources: IENE and DESFA*[15]**

As already discussed, the aforementioned projections could be considered as conservative. This is reinforced from DEPA's[16] projections in which consumption in Greece is estimated to increase to 8 bcm over the next 15 years.

(g) FYROM

Gas Demand and Supply

FYR of Macedonia's gas share in gross inland consumption in 2015 was 4.2%, very close to 2014 levels. In terms of final energy consumption, almost all the natural gas in 2015 was consumed by industry (84%). There are no gas production or gas exploration activities in the country.

Since 2005 up to 2015, FYR of Macedonia's net gas imports almost doubled; from 62 ktoe or 0.07 bcm in 2005 to 112 ktoe or 0.13 bcm in 2015. Almost the entire supply of gas is imported from Russia through the only entry point at the Bulgarian border. The distribution network in the city of Strumica, in the South of the country, is not connected with the transmission network and supply is ensured by truck transport of compressed natural gas (CNG) from Bulgaria. FYR of Macedonia is 100% dependant on natural gas imports.

[15] DESFA study for the development of ESFA 2018-2027
[16] DEPA - IA:2017-09-27 TEE DEM

Table 10 – Natural gas demand and supply in FYROM, 2015

bcm	Gas
Primary production	-
Imports	0.13
Gross inland consumption (Natural gas)	0.13
Final energy consumption (Natural gas) by selected sectors:	0.04
- Industry	0.03

Sources: Eurostat (2017), IENE

FYROM's Gas Outlook

Currently, natural gas demand in FYROM is approx. 0.2 bcm/year all of which is imported via Bulgaria. In line with FYR of Macedonian Energy Resources (MER)'s estimations, the gas consumption in FYROM is estimated to elevate to 0.4 by 2020, 0.6 by 2025 and up to 1 bcm until 2040.

(h) Italy

Italy's gas market is the third-largest in Europe. Over the past six years, the country has invested significantly in new infrastructure but is now experiencing a period of falling demand as the economic crisis continues to hurt and demand for gas-fired power is offset by the growth in electricity generated from renewable sources and energy efficiency. Furthermore, despite the implementation of many new measures to facilitate the emergence of a competitive gas market, end-user prices remain high by European standards while wholesale prices appear to be converging with other markets.

Gas Demand and Supply

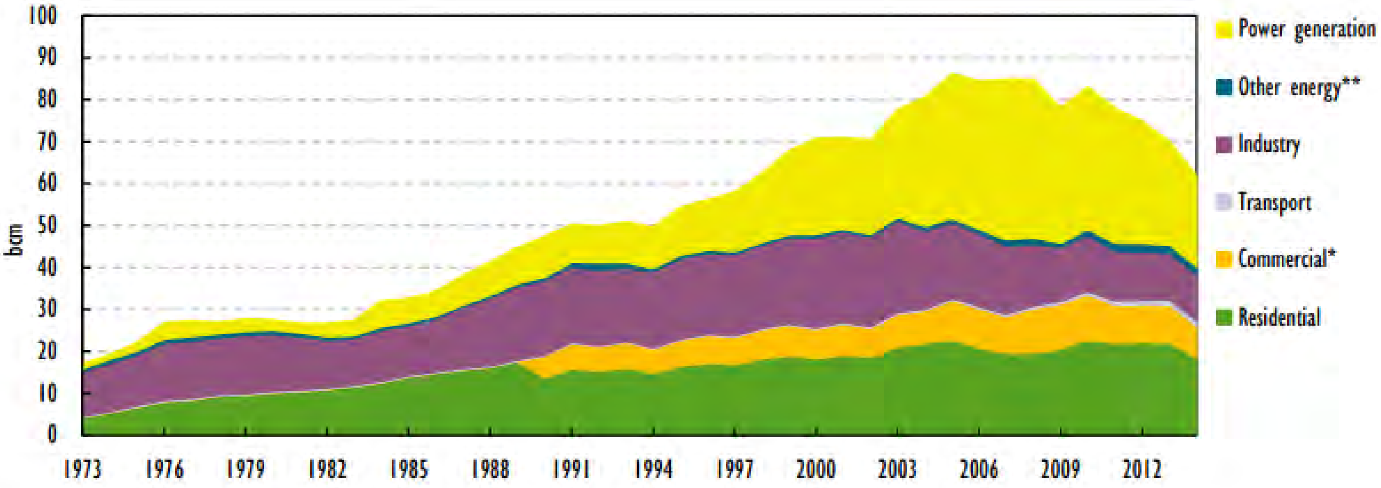
According to IEA (8), natural gas is the largest fuel in Italy's energy sector, representing 36.7% of total primary energy supply (TPES) and 38.3% of electricity generation in 2015. Natural gas supply was 55.3 Mtoe in 2015, increased by 9.1% from the year before. Italy's gas share in gross inland consumption in 2015 was 35.4%, increased by roughly 2% from 2014 levels. In terms of final energy consumption, the largest part of the natural gas in 2015 was consumed by households (51%) and industry (26%), while transport sector stood at about 3.3%. The share of natural gas in Italy's primary energy production was 15.3% in 2015 and corresponded to 5,545 ktoe or 6.6 bcm, declined by 5.3% from 5,855 ktoe or 6.97 bcm in 2014. Production peaked in 1994 and has been falling since, as resources depleted; it was 56.1% lower in 2015 than in 2005. At present, there are 719 active gas well assigned to 26 concessions.

The power generation sector is the main consumer of natural gas with 35.2% of inland consumption in 2014. Demand from other sectors was: residential 29.9%, industry 17.9%, commercial and other services 12.1%, other energy industries and energy own-use 2.9% and transport 2.1% (see Figure 11).

Following the economic downturn and changes to the underlying structure of the sector, industry demand decreased sharply over the past decade with its share in total consumption falling from 23.2% in 2004 to 17.9% in 2014. Demand in the power generation sector has also declined sharply from a top level of 38.3bcm in 2007 to 21.8bcm in 2014. The power generation's share in total natural gas consumption has also decreased from the highest share in 2007 (45.1%) to the 35.2% value in 2014.

The only sector that has shown continuous growth in the last decade is the transport sector, which has increased their demand for natural gas by over 200% since 2004. The absolute values, however, are small with a 2.1% share of total demand, up from 0.5% in 2004. Household consumption fell in 2014 compared to previous year (17%), and is back at a level similar to consumption during 1998-2002. The commercial and public services (including agriculture) also showed a decline in natural gas consumption in 2014 (7.5%), which brings it down to a level similar to 2004.

Figure 11 – Italy's natural gas supply by sector, 1973-2014



Note: methodology for residential and commercial consumption changed in 1999.

* *Commercial* includes commercial and public services, agriculture/fishing and forestry.

** *Other* includes other energy industries and energy own-use.

Source: IEA (2016c)

Since 2005 up to 2015, Italy's net gas imports recorded ups and downs; from 61,600 ktoe or 73.33 bcm in 2010 to 45,471 ktoe or 54.13 bcm in 2014 and to 49,996 ktoe or 59.52 bcm in 2015. Imports originated from Russia (43.1%), Algeria (12.2%), Libya (11.7%), Netherlands (11.7%), Qatar (7.9%) and others. Imports from Libya, Qatar, Germany, Austria and Croatia all started in 2003. Previously, imports originated mainly from Russia, Algeria, the Netherlands and Norway. Since 2004, imports from Algeria, Norway, and the Netherlands have declined by 73.6%, 48.6%, and 19.1% respectively, while imports from Russia have increased by 1.7%. Exports were to Switzerland (41.4%), Slovenia (29.5%), and Austria (29.1%). Italy has diversified its natural gas imports over the same period.

Table 11 – Natural gas demand and supply in Italy, 2015

bcm	Gas
Primary production	**6.6**
Imports	**59.73**
Gross inland consumption (Natural gas)	**65.83**
Final energy consumption (Natural gas) by selected sectors:	**39.5**
-Industry	10.08
-Transport	1.29
-Residential	20.22

Sources: Eurostat (2017), IENE

Italy's Gas Outlook

Italian system operator Snam expects weather-adjusted gas consumption to remain broadly unchanged in 2017 as higher efficiency offsets strong industrial and power sector gas demand. Weather-adjusted aggregate consumption is expected to be broadly in line with the 71.9 bcm in 2016.

A gradual growth of about 1.9% every year is foreseen for Italian gas demand during the ten-year period 2016-2025, both for the increase of macroeconomic framework and electric demand, and for the activation of supports to the gas demand, as for example biomethane and increments of gas used as fuel in transports. Table 12 shows annual demand for each market sector.

Table 12 – Natural gas and biomethane demand forecast in Italy

bcm	2019	2025	2030
Residential and commercial	29.1	26.5	24.4
Power generation	25.9	33.0	36.5
Industry	14.6	14.4	13.9
Other (*)	2.8	4.7	6.5
Consumption and losses	2.3	2.7	2.8
Total demand	**74.6**	**81.2**	**84.1**

Note: (*) Including consumptions for Agriculture and Fishing, Chemical synthesis, automotive and bunkering

Source: Snam Rete Gas[17]

[17] http://pianodecennale.snamretegas.it/en/executive-summary/gas-demand-and-supply-in-italy.html

Gas imports will continue to be the primary source to satisfy the gas demand and they will be able to increment always more effectively thanks to the growth of the transit role played by the Italian gas system, supported by the developments projects of import and export of the Italian network.

Table 13 – Natural gas and biomethane supply forecast in Italy

bcm	2019	2025	2030
Import	65.7	74.6	75.7
Production	10.0	11.7	13.5
Export	-1.1	-5.1	-5.1
Total availability (*)	**74.6**	**81.2**	**84.1**

Note: (*) Not including stock variation

Source: Snam Rete Gas

The planned development of transmission capacities for the ten-year period set by Snam Rete Gas allows to meet both the forecast demand in Italy and exports. In particular, it is forecasted the start of export at Passo Gries from 2019 and an increase in export volumes up to 5 bcm until 2022.

While Italy has access to multiple gas supply sources, the supply mix is heavily dependent on Russian. In the future, the reliability of North African imports – which have traditionally been the main diversification option to Russian gas – remains questionable. While ENI has strongly reduced its imports of Algerian gas in recent years owing to the sharp reduction in domestic demand, it is unclear to what extent Algeria could ramp up exports to levels seen early in this decade. There has been limited new investment in the Algerian upstream sector while fast growing demand may limit the availability of gas for export. ENI, Enel and Edison hold commercial gas supply contracts with Algeria (Sonatrach) and these will expire in 2019. Commercial gas transit contracts with Tunisia will also expire in 2019. Signing new supply contracts in the context of reduced internal demand and an ever-increasing share of hub-linked prices in Europe might also prove challenging.

During March to September 2011, gas supply from Libya came to a complete halt because of war, then slowly resumed in October and returned to full capacity in late 2013. Deliveries from Libya are directly linked to the precarious political situation in the country, which continues cause concern. An increase in production and exports beyond current average levels is unlikely. Increased imports from Russia have offset reduced deliveries from North Africa in the recent past. ENI, Italy's largest importer of gas from Russia, has long-term contracts terminating in 2035 and this gas is currently supplied by pipeline via Ukraine and Slovakia. In winter months, imports from Russia cover well over 40% of total imports. Repeated cuts in supply, caused by commercial and political disputes between Russia and Ukraine in 2006 and 2009 have given rise to concerns regarding the reliability of future Russian gas deliveries transiting Ukraine, given the deepening of the political crisis between the two countries.

In more recent winters, Ukraine has proven to be a reliable transit route for transportation of Russian gas to European markets but future interruptions during the winter season cannot be ruled out. In response, Italy has implemented further gas security measures and built new import infrastructures (Italy now has a total import capacity of 15 bcm/year of LNG supply and over 16 bcm of storage capacity, including strategic storage). In the medium term, LNG markets are likely to offer increasing opportunities to source spot cargoes as a result of oversupplied LNG markets and the emergence of more flexible LNG volumes as new facilities in the US are commissioned. Gazprom had been developing the South Stream project, and following its cancellation at the end of 2014, the Turkish Stream project was initiated in order to supply gas to Italy via a new route bypassing Ukraine. Realisation of the Turkish Stream project is uncertain and it remains unclear if, and how, Russian gas could be supplied to Italy via the planned Nord Stream expansion. Under these circumstances, it is likely that Ukraine and Slovakia will remain key transit countries for Russian gas supplied to Italy.

While uncertainties surround most traditional suppliers, one new source of supply for Italy and for the rest of Europe is being developed in the Caspian area. The "Southern Gas Corridor" project, starting in the Shah Deniz 2 offshore field in the Caspian Sea, which crosses Azerbaijan, Georgia, Turkey, Greece and Albania and lands in Italy via the Trans-Adriatic Pipeline (TAP) is set to be opened in 2020. It will transport 10 bcm of gas per year, of which 8.8 bcm is destined for Italy. The Italian government gave its final approval to the project in May 2015. While this latest project is a welcome development, the new quantities of gas available through the Southern Gas Corridor will be limited. There is potential for doubling the capacity of the TAP pipeline to 20 bcm/year and expanding supplies via the TANAP pipeline through Turkey if more Caspian gas becomes available. The gas supply potential from this region beyond Shah Deniz 2 may be greater, especially from other offshore fields in Azerbaijan, Turkmenistan, Iran or northern Iraq, but will require strong political engagement, co-operation among all interested stakeholders, in particular Georgia, Azerbaijan, Turkmenistan and Turkey, as supply or transit countries and viable commercial agreements materialise.

Last but not least, the export potential for offshore gas in the eastern Mediterranean is unconfirmed; however, major finds have been made, beyond Israel, recently offshore Egypt by ENI and further exploration activities are is underway.

Overall, the most secure option to diversify gas supplies in the medium term appears to be the development of LNG trade with key partner countries.

(i) Ukraine

Gas Demand and Supply

According to IEA's Gas Market Report 2017, Ukraine's gas consumption slightly decreased in 2016 to a record low level of 33 bcm or 27.7 mtoe amid colder temperatures and improved economic activity, marking a 50% decrease over ten years and an almost 40% decrease over the past four years. This comes during a slight economic recovery and a minor increase in electricity demand. While the loss of control over some territories within Ukraine accounts for about 5 bcm or 4.2 mtoe, the remainder of the decrease is explained by higher prices and tariffs, recession, centralised district heating savings and fuel switching. Household consumption is down to 13 bcm or about 11 mtoe, from an average of 18 bcm or about 15 mtoe at the start of the decade.

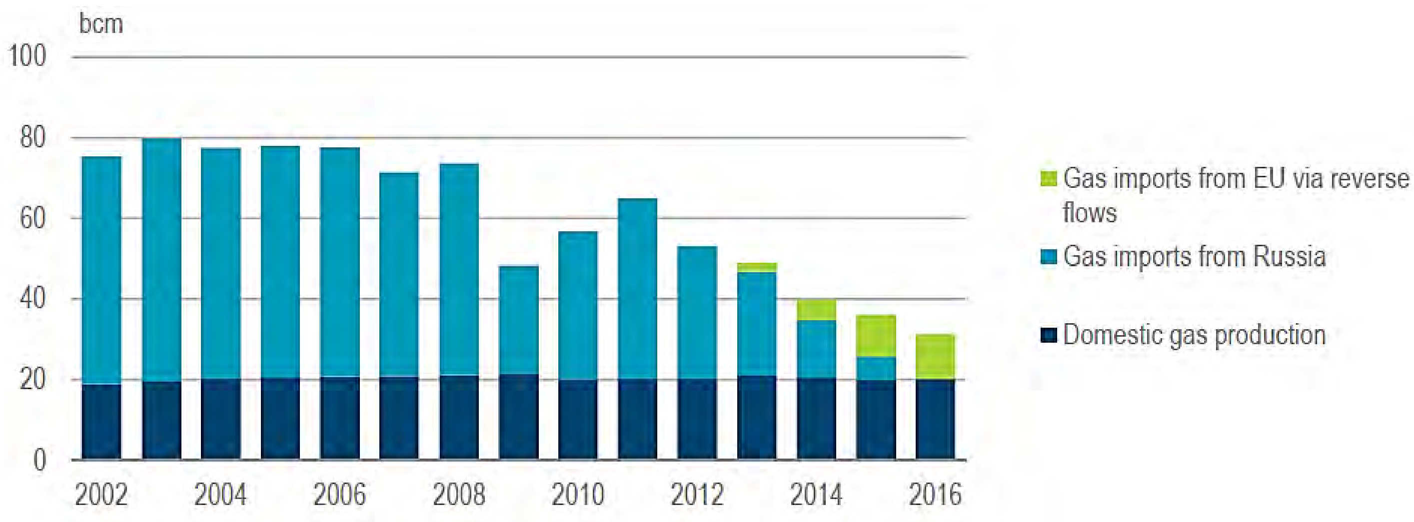
Ukraine's gas share in gross inland consumption in 2015 was 29.3%, decreased by roughly 2.5% from 2014 levels. In terms of final energy consumption, the largest part of the natural gas in 2015 was consumed by households (56%) and industry (32%), while transport sector stood at about 9.7%. The share of natural gas in Ukraine's primary energy production was 24.7% in 2015 and corresponded to 14,818 ktoe or 17.64 bcm, declined by about 1.5% from 15,049 ktoe or 17.92 bcm in 2014.

Ukraine's gas consumption is expected to increase slightly by 2022. The economy is expected to recover, and while there will be significant energy efficiency and gas saving investments by 2022, some heavy industries are expected to shut down production. The slight pickup in industrial gas consumption could be offset by lower technical gas consumption if transit volumes decrease, as well as lower consumption in the residential and district heating segment.

Due to the improvements in the regional gas system of Eastern Europe, Ukraine sourced all its imports in 2016 via reverse flows from the European Union, without directly buying gas from Russia. Current import capacity from the European Union stands at 22 bcm per year and is expected to increase further when an additional interconnection with Poland becomes operational by 2020. Ukraine has ensured safe transit of Russian gas to the European market in recent years despite facing extremely challenging economic circumstances. Gas transit obligations have been respected while experiencing strong economic decline and the conflict with Russia.

Since 2005 up to 2015, Ukraine's net gas imports fell sharply; from 48,263 ktoe or 57.45 bcm in 2005 to 13,292 ktoe or 15.82 bcm in 2015. The share of gas imports from Russia displayed the highest decrease in the period between 2011 and 2015, mainly due to the lower gas demand and Ukraine's import diversification policy. At the same time, gas imports from EU (Hungary, Slovakia and Poland) increased from 0 bcm in 2011 to 11.3 bcm in 2015. The diversification of the gas imports was mainly driven by political issues and supported by EBRD and World Bank loans for gas consumption from prequalified EU-based suppliers. Figure 12 depicts Ukraine's gas balance from 2002 to 2016.

Figure 12 – Ukraine's gas balance, 2002-2016



Source: IEA (2017)

Table 14 – Natural gas demand and supply in Ukraine, 2015

bcm	Gas
Primary production	**17.64**
Imports	**15.82**
Gross inland consumption (Natural gas)	**31.03**
Final energy consumption (Natural gas) by selected sectors:	**19.23**
-Industry	6.16
-Transport	1.87
-Residential	10.82

Sources: Eurostat (2017), IENE

Ukraine's Gas Outlook

Gas consumption in Ukraine amounted to 33.2 bcm in 2016 of which 20.1 was indigenous production and 11.1 bcm were imported, all from EU markets (mainly via Slovakia but also via Hungary and Poland). In 2016, Ukraine did not import Russian gas. Demand is estimated to remain relatively stable over the following years[18]

Discussion

Table 15 shows the gas production and consumption in SE Europe in 2008, 2015 and 2025, highlighting the low gas production and the need for the SEE countries to import increased natural gas volumes. What is evident is the substantial contribution of Turkey in total gas consumption in SE Europe, which is expected to increase further by 2025, corresponding to more than 63% of the total. Turkey is the region's major gas consumer and importer by far and its interest in natural gas is strong both as a potential producer but also as a transit country to European markets. On the transit side, virtually all of the various gas pipeline projects, which plan to transport Caspian gas to the European markets, involve Turkey as a transit country (e.g. TANAP and Turkish Stream). Chapter 5a refers to these projects in detail.

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[18] KPMG, Situation of the Ukrainian natural gas market and transit system, 2017

Table 15 – Natural gas production and consumption in SE Europe (2008, 2015 and 2025e)

Country	2008		2015		2025e	
	Gas production (bcm/y)	Gas consumption (bcm/y)	Gas production (bcm/y)	Gas consumption (bcm/y)	Gas production (bcm/y)	Gas consumption (bcm/y)
Albania	0.02	0.02	0.0	0.0	0.01	0.22
Bosnia and Herzegovina	0.0	0.31	0.0	0.3	0.0	0.45
Bulgaria	0.31	3.5	0.1	3.1	0.21	4.3
Croatia	2.03	3.1	1.75	2.48	1.52	3.3
Cyprus	0.0	0.0	0.0	0.0	0.0	0.0
FYROM	0.0	0.05	0.0	0.13	0.0	0.6
Greece	0.0	4.25	0.009	3.2	0.0	6.0
Kosovo	0.0	0.0	0.0	0.0	0.0	0.0
Montenegro	0.0	0.0	0.0	0.0	0.0	0.0
Romania	11.2	16.9	10.46	10.6	10.02	14.1
Serbia	0.25	1.92	0.54	2.08	0.51	2.8
Slovenia	0.0	0.51	0.0	0.8	0.0	1.07
Turkey	1.03	36.9	0.37	46.9	0.73	56.0
Total	**14.84**	**67.46**	**13.23**	**69.59**	**13.00**	**88.84**

Sources: IENE[19], IEA, 10-year Development Plans of gas TSOs, BP Statistical Review for World Energy 2017

The capacity of gas interconnectors and other entry points in selected SE European countries, including storage facilities and LNG terminals, is shown in Table 16.

Table 16 – Capacity of interconnectors and other entry points of main destination markets

Country	Name/ Location	Type	Capacity (GWh/d)	Total (GWh/d)
Greece	Sidirokastro	Pipeline BG → GR	122	321
	Revithousa	LNG Terminal	150	
	Kipi	Pipeline TR → GR	49	
Bulgaria	Negru Voda 1	Pipeline UA → BG	151	758
	Negru Voda 2 and 3	Pipeline UA → BG	563	
	Chimen	Storage	43	
Serbia	Kiskundorozsma	Pipeline HU → RS	142	199
	Banatski Dvor	Storage	57	
FYROM	Zidilovo	Pipeline BG → MK	20	20
Turkey	Malkoclar	Pipeline BG → TR	451	1,707
	Blue Stream	Pipeline RU → TR	394	
	Dogubayazi	Pipeline IR → TR	282	
	Baku-Tbilisi-Erzurum	Pipeline GE → TR	186	
	Aliaga	LNG Terminal	169	
	Marmara Ereglisi	LNG Terminal	226	

Source: ENTSOG

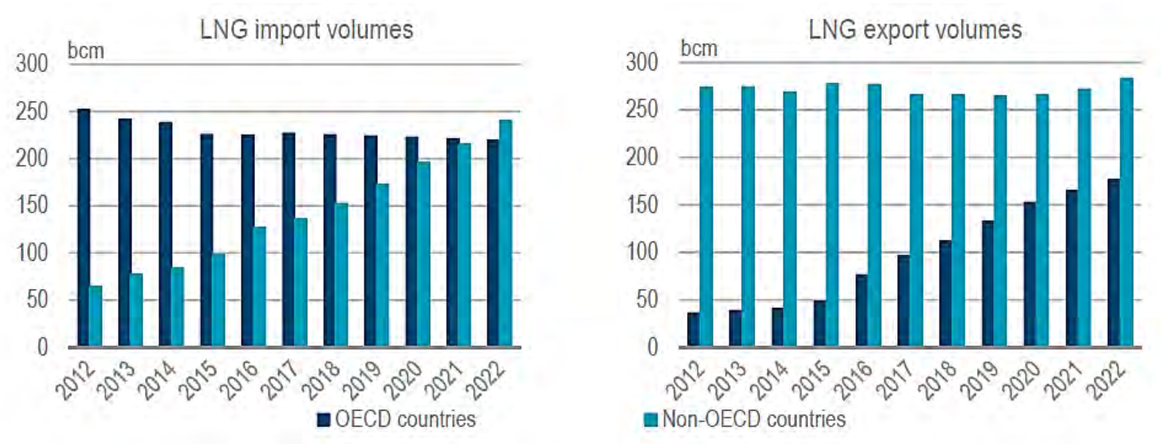
[19] IENE's "SE Europe Energy Outlook 2011", Athens, Greece.

4. The rising role of LNG in meeting global gas demand

LNG Trade

In 2016, global LNG trade grew by around 25 bcm. It is expected to grow faster than pipeline trade, by an annual rate of 4.5%, so that by 2022 LNG trade equals 460 bcm, based on data provided by IEA's Gas Market Report 2017. Growth in LNG supply capacity will be faster than the growth in LNG demand, and the 75% of new supply capacity will come from two countries, Australia and the United States. China will be the main driver of the global LNG demand growth, and relatively new importers will also show large increases in LNG demand. OECD countries have traditionally been the largest source of global LNG demand, but LNG import volumes of these countries have decreased and this tendency will continue throughout the forecast period (see Figure 13). By contrast, LNG demand of non-OECD countries has increased rapidly, backed by the growing gas demand of these countries, and LNG import volumes of non-OECD countries will exceed those of OECD countries in 2022. The LNG export side shows a different picture. Historically, LNG exports have come predominantly from non-OECD countries, but the surge of new liquefaction capacity in Australia and the United States and the stagnation of LNG export capacity in non-OECD countries have resulted in a more balanced picture.

Figure 13 – World LNG imports and exports, OECD and non-OECD, 2012-22



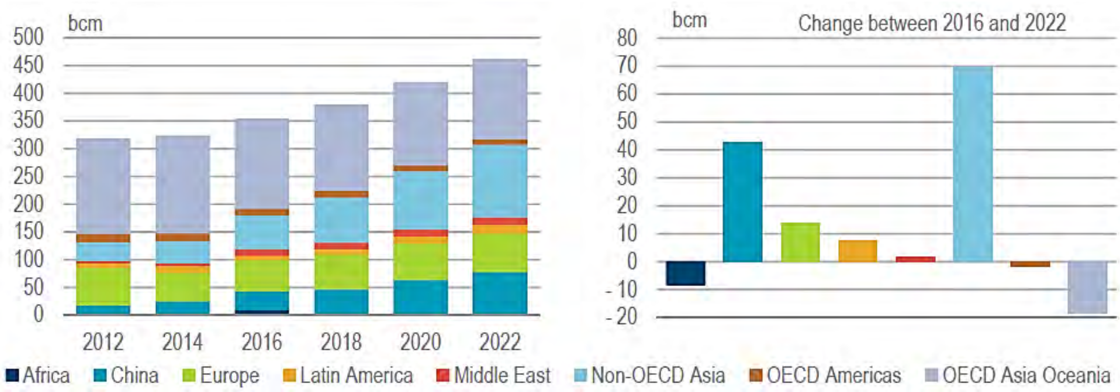
Source: IEA (2017a)

LNG Demand

IEA's report forecasts that global LNG demand will reach 460 bcm in 2022, increasing by more than 100 bcm compared with the 2016 level, or more than 30% growth over the forecast period (see Figure 14 and Map 4).

From 2016 to 2022, China will show the largest LNG import increase in the global LNG market, and its LNG demand will increase more than 40 bcm by 2022 from the 2016 level. Non-OECD Asia (excluding China) is expected to experience a steady growth path through the forecast period, adding around 70 bcm to 2016 LNG demand. India is also seen as an emerging LNG importer, capable of generating a meaningful demand increase with impressive growth rates of around 11% per year, and its LNG import volume will be double the 2016 level. Bangladesh, Indonesia and the Philippines are forecast to join the LNG import club and to start importing LNG before 2020.

Figure 14 – World LNG imports by region, 2012-22



Source: IEA (2017a)

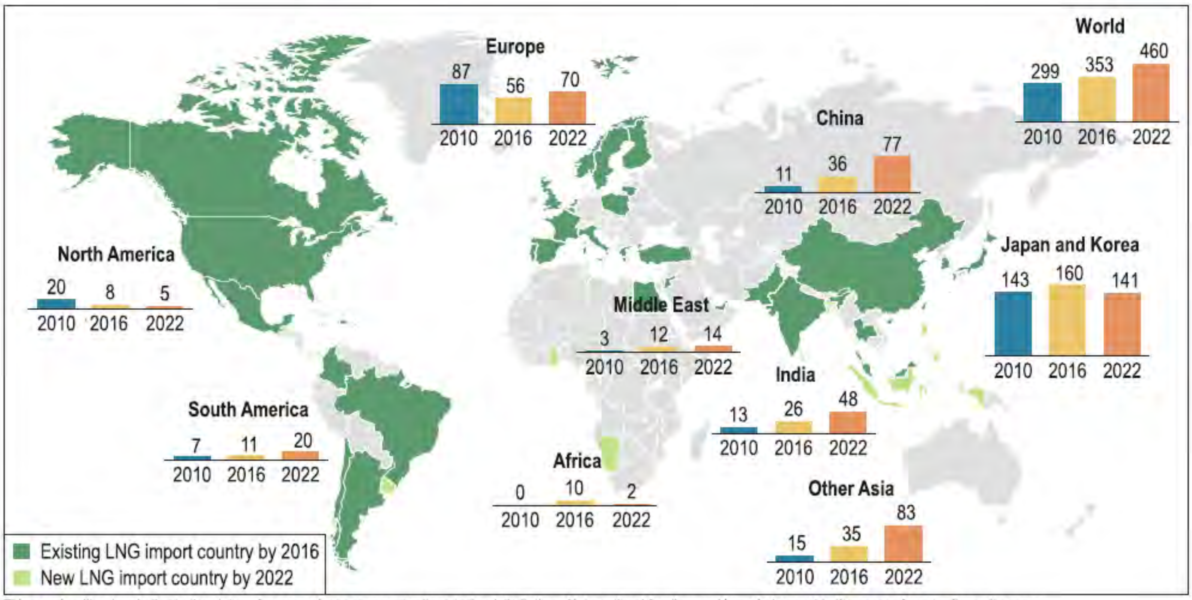
In OECD Asia Oceania, Japan and Korea together continue to make up the largest LNG-importing region, but its imports will decline by 12% between 2016 and 2022, in contrast with the strong growth observed over the last decade. In Japan, assuming a modest recommencement of nuclear power, demand may be below contracted volumes from 2017. In Korea, the government changed in Q2 2017. The target of the government is to reduce nuclear and coal power generation output, creating new possibilities for gas.

Stagnating demand and decreasing production will increase Europe’s import needs over the forecast period. Europe’s LNG demand has been and will be lower than the contracted LNG volumes, mainly because of weak gas demand after the euro crisis and competition from pipeline gas. The expiration of LNG contracts in the coming years will allow Europe to rebalance the long positions.

Latin America will see some LNG demand increase with the addition of Colombia, Haiti, Panama and Uruguay. LNG demand in Canada, the United States and Mexico, in OECD Americas, loses ground due to the strong competition with pipeline gas in the region.

Though Ghana and Namibia are assumed to start importing LNG in the coming years, overall African LNG demand in 2022 will be around 2bcm, one fifth of the 2016 level, mainly because Egypt is expected to benefit from domestic production of its new gas fields and ease its existing importing needs substantially.

Map 4 – World LNG imports by region, 2012-22



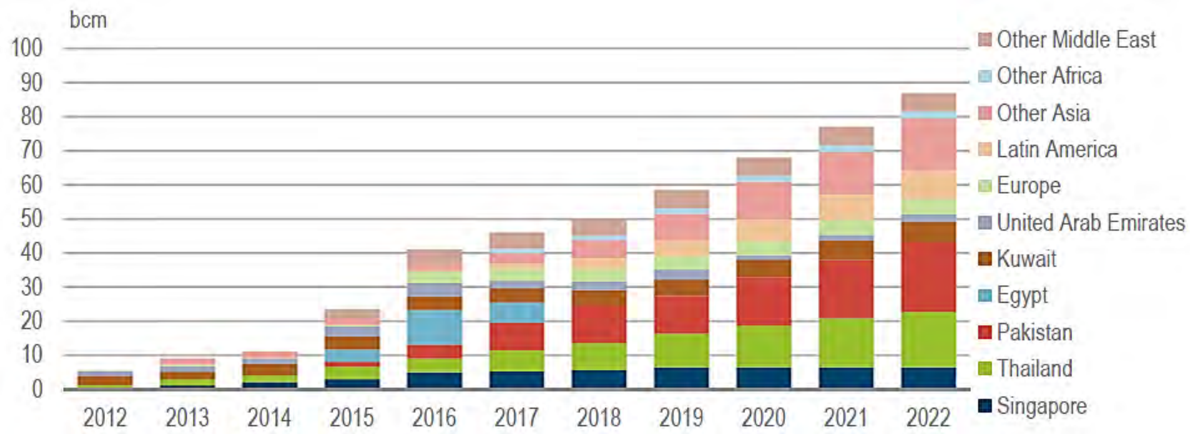
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: IEA (2017a)

New small players

One of the most interesting aspects in the recent LNG trade is the growing role of the new but small players. The group of small importers, mostly with a short history in the LNG market or at least not importing large volumes traditionally, has grown significantly over the last few years (see Figure 15). Three of those importing countries, Egypt, Jordan and Pakistan, started importing LNG from 2015 and imported more than 18 bcm in 2016, as much LNG as imports by the United Kingdom and France combined. Other relatively new small players such as the United Arab Emirates, Kuwait, Thailand and Singapore grew significantly, importing in 2016 more than two times the volumes imported in 2013.

Figure 15 – Growth from small and new LNG importers, 2012-22



Source: IEA (2017a)

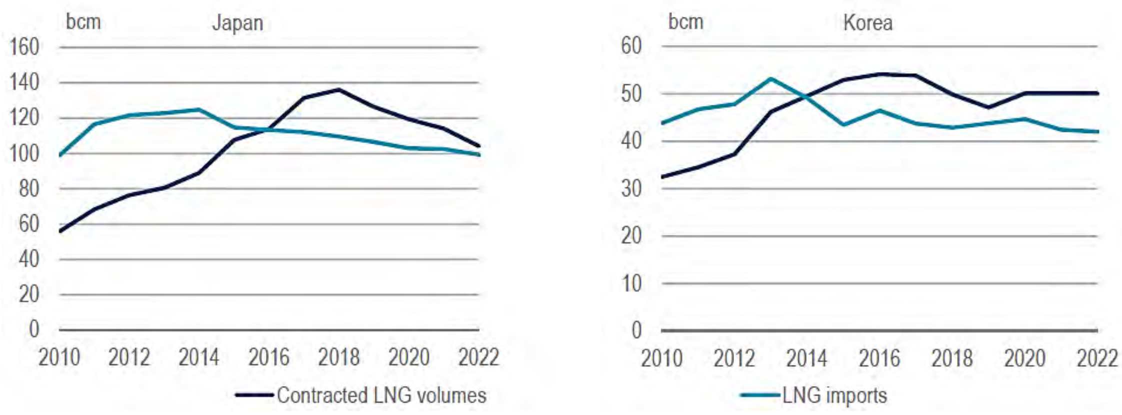
Egypt has become one of the most interesting LNG players in the oversupplied global LNG market. With the finding of a new large gas field, Egypt cancelled its third FSRU, which it had planned to introduce in 2017. IEA's report forecasts that Egypt's LNG imports will probably decrease to zero in the coming years. Pakistan will increase its LNG import significantly to around 20 bcm in 2022 and become the sixth largest LNG import country just behind Chinese Taipei.

In addition, from 2014, other countries such as Colombia, Finland, Jamaica, Lithuania, Malta and Poland have joined the club of LNG importers, and Bahrain, Bangladesh, Ghana, Haiti, Indonesia, Namibia, Panama, the Philippines and Uruguay are expected to start importing LNG during the forecast period. However, actual demand will depend on LNG prices and competitiveness against alternative fuels in their respective domestic markets. This surge of new and small importers will bring new pockets of demand. LNG imports of these new and small players will be more than double the 2016 level and account for around 20% of global LNG trades, close to those of Japan or China.

Japan and Korea

Historically, Japan and Korea have been the largest LNG importers. Japan reached a turning point in 2016, when its LNG demand started to lag behind its contracted LNG volumes (see Figure 16). The gap between contracted volumes and imported volumes was reduced to reach a balance point in 2016, and from 2017 onwards, the addition of new contracts and decreasing demand will result in a significant over-contracted position for the first time. The gap will see the surplus peak in 2018, reaching around 25 bcm, and then gradually shrink to around 5 bcm in 2022. One of the tools to manage this potential oversupply is destination flexibility of LNG, and from 2018 to 2022, Japan could utilise around 15 bcm of contracted volumes with flexible destinations by diverting their agreed volumes to other LNG-importing countries where LNG is needed. In fact, Japanese LNG importers have already started such adjustments with European LNG importers. In June 2017, the Japan Fair Trade Commission released its review aiming at ensuring fair competition in LNG trades, and stated that competition-restraining clauses or business practices should be eliminated from new or revised LNG contracts, and LNG sellers should review such clauses or business practices in existing contracts.

Figure 16 – Demand and contracted volumes relationship in Japan and Korea, 2010-22



Source: IEA (2017a)

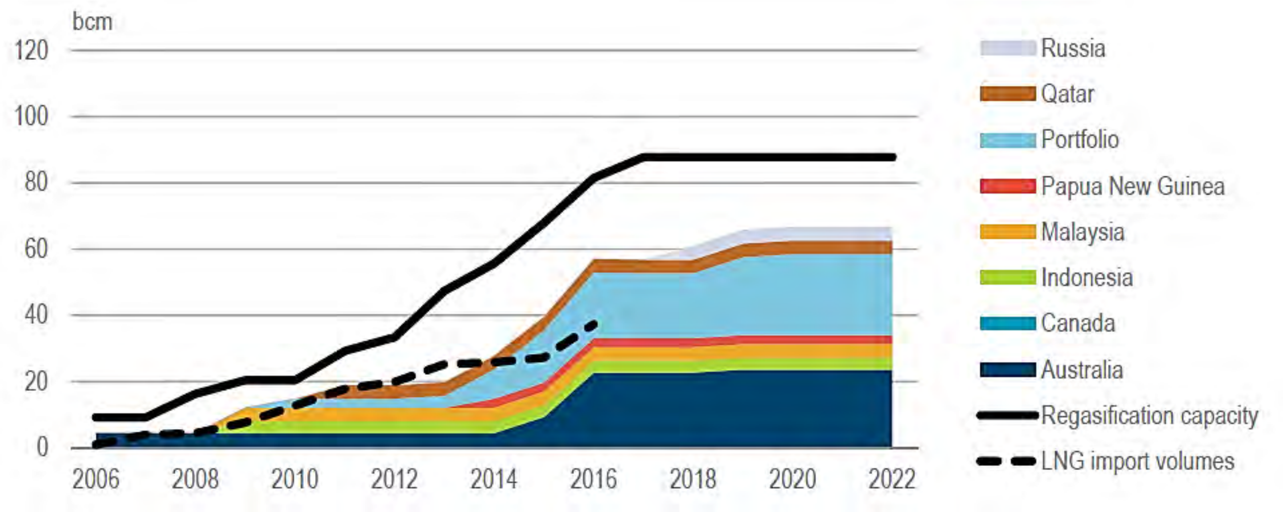
Korea would face the same situation with different timing, but the over-contracted volumes would be smaller than Japan. Korea´s contracted level reached and surpassed its LNG demand back in 2015 with around 9.5 bcm of surplus. It will peak in 2017 with 10 bcm per year of surplus and will decrease to around 8 bcm in 2022. Korea has around 4 bcm per year of destination-free LNG until 2019 and around 7 bcm from 2020 onwards. However, the Korean government changed in Q2 2017. The new government targets a nuclear phase-out and curtailment of coal-fired power generation, which would lead to an increase in gas use. In that case, LNG imports in Korea would increase and over contracted position could be mitigated. Developments in these two countries highlight the importance of greater flexibility in the LNG supply chain, while still ensuring security of supply.

China

China's LNG imports are still well below their contractual level; however, the country continues ramping up: between 2015 and 2016, China's LNG imports increased from around

27 bcm to 36 bcm, a y-o-y growth of 35%, and January to May 2017 saw a further increase of around 30% compared with the same period in 2016.

Figure 17 – LNG import sources and volumes in China, 2006-22

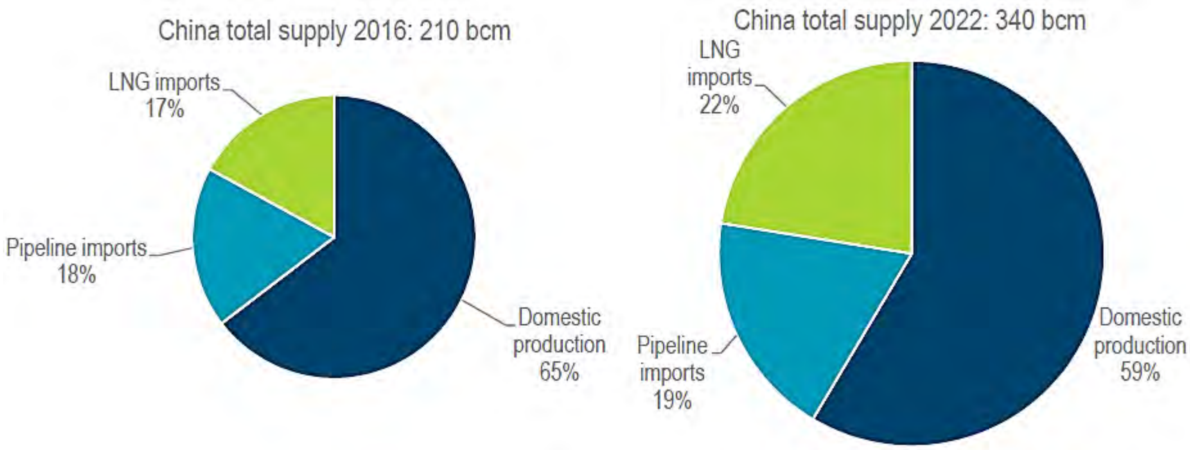


Source: IEA (2017a)

At the end of the forecast period, China will have contracted around 66 bcm, and LNG imports are well placed to meet potentially burgeoning demand in cities. Additionally, the country is preparing for options to import even beyond that level. In March 2017, China National Offshore Oil Corporation (CNOOC), Japan's JERA and Korean Gas Corporation (KOGAS) signed a memorandum of understanding, discussing opportunities for mutual collaboration in the LNG business including joint procurement of LNG. China's LNG regasification infrastructure is prepared for this event, as projects under construction are expected to see further expansion in 2017, increasing by 6 bcm to reaching around 88 bcm.

During the forecast period, LNG imports are expected to be the supply source of choice. Coastal areas will be an important driver for gas demand growth as the pressure to improve air quality is very high in the cities along the coast. The proximity of coastal demand areas to the existing regasification infrastructure makes LNG the preferred option, with lower transportation costs than pipeline imports and a well-supplied market that puts large importers in a good position to contract additional quantities at competitive prices.

Figure 18 – China's supply portfolio, 2016 and 2022



Source: IEA (2017a)

Europe

While the action on the capacity side of LNG is an Australian and American story, the ultimate controlling player of the emerging global gas market is likely to be Europe. This is because Europe is likely to act as a "clearing house" for surplus LNG cargoes given it has excess re-gasification capacity (about 221 bcm), as shown in Map 5, and the ability to use the fuel for a variety of purposes, from power generation to manufacturing to household heating. Also, Europe is the only region that can effectively arbitrage between LNG and pipeline prices, given its connection to Russian and other Eastern natural gas via pipelines. In addition, the continent is best-placed to use market forces to find a price level for gas versus its competitors, given it still has substantial coal-fired power in some countries as well as being a leader in renewables such as wind and solar.

The contracting regime for European LNG trading is rapidly changing in important ways. Long-term contracts are becoming shorter; there are more medium- and short-term deals, the latter defined as less than two years, as there is a push towards more open and competitive markets, to hub-indexed gas price formation and spot trading. There is more interest in breaking the destination clause restrictions thus allowing more contracted supply to be diverted to other terminals in response to market needs. Pricing terms are also changing with the addition of hybrid pricing terms: some deals are linked to spot indices or sometimes to local price indices, in addition to traditional linkages to various oil indexes or a combination of all of these.

Map 5 – LNG Capacity in Europe

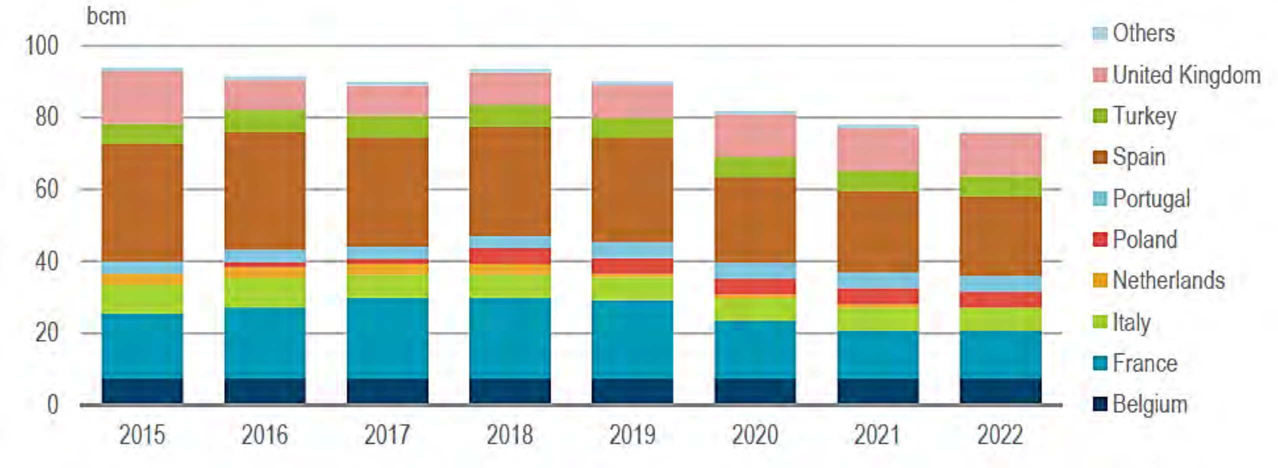
Notes: Markets with very limited liquidity, Physical markets with limited interconnection, low liquidity, & limited ability to absorb LNG, Markets with high access costs, regulatory constraints, and/or volatile spreads markets to hedging hubs and OMV estimate suggests 40-50 bcm capacity in efficient price hedging locations.

Source: OMV Gas[20]

Despite the fact that Finland, Lithuania, Malta, Poland and Sweden recently joined the club of LNG importers in Europe, there is a remarkable decline in contracted volumes among other countries in Europe across the horizon of this forecast due to expiring contracts (see Figure 19). Assuming that the majority of them will not be renewed, the contracted volumes where Europe is the intended destination in 2022 will be 20% lower than the contracted quantity in 2015, decreasing from 94 bcm to 76 bcm, according to the IEA.

[20] Williamson, A. (2018), "Changes in Dynamics and Pricing of LNG in the Atlantic Basin", http://www.wraconferences.com/wp-content/uploads/2018/02/1025-Andy-Williamson-OMV-Gas-Marketing-Trading.pdf

Figure 19 – LNG contracted volumes in Europe, 2015-22



Source: IEA (2017a)

The decline of LNG contracted volumes will mainly come from the three largest LNG-importing countries in Europe – France, Spain and the United Kingdom. Contracted quantities of LNG intended for Spain will be largest, followed by France and the United Kingdom to a lesser extent. The over-contracted position of Spain and France will shrink but will still remain and that of the United Kingdom will stand close to balance over the forecast period. Therefore, the flexibility provided by Europe in the past in the form of LNG diversions and reloading will be sharply reduced.

By 2022, Spain is expected to have about 10 bcm less of contracted volumes than in 2015. It is worth mentioning that some Spanish players have entered long-term agreements with US exporters, but contracted volumes will not necessarily go to Spain or to other countries in Europe if there are other lucrative markets, as already witnessed in 2016.

Whereas current information shows that contracted LNG volumes in Europe will be decreasing, the same does not hold true for spot trades. According to Platts[21], it is anticipated that spot trading will come to fill in the gap with anticipated gas volumes delivered to European destinations. "In a well-supplied market and given the significant quantities under long-term contracts, which are due to expire in the medium-term, the share of spot and short-term volumes could increase further in the coming years", GIIGNL[22] president Jean-Marie Dauger recently said. This mean that overall European LNG sales will

[21] https://www.platts.com/latest-news/natural-gas/london/spot-lng-trading-makes-up-18-of-total-lng-volumes-26695262

[22] GIIGNL stands for the International Group of Liquefied Natural Gas Importers.

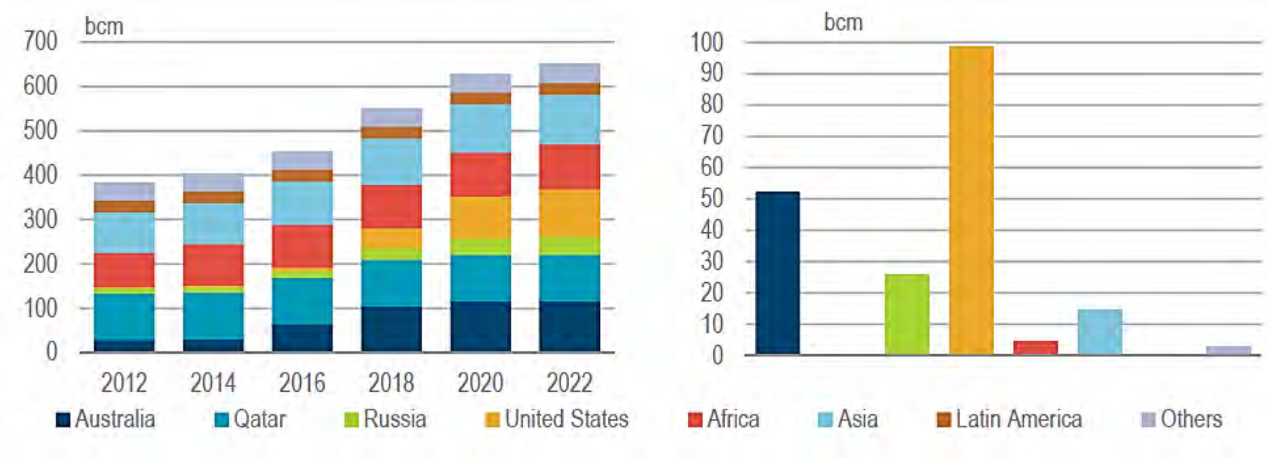
not shrink but on the contrary will remain flat in a worst case scenario, with most analysts convinced that total LNG sales will exhibit a growing trend beyond 2020.

LNG Supply

By the end of 2016, global LNG export capacity reached 451.8 bcm, increasing 7.4% relative to the previous year (see Figure 20). IEA's report expects 97% of the additional capacity to come from already-sanctioned projects. This outlook assumes four additional projects – Sabine Pass Train 6 and Corpus Christi Train 3 in United States, Fortuna FLNG project in Equatorial Guinea, and Sakhalin II Train 3 in Russia – might take FID in time for a production start-up within the forecast horizon of this report. Three of these projects will be expansions to existing facilities with relatively low costs, and one will be FLNG, and therefore these four projects should come on line with short construction times.

A major boost to export capacity is expected from 2017 to 2019 with average capacity additions of around 50 bcm each year with the start-up of large projects in Australia and the United States, but capacity increase will slow from 2020 onwards. By the end of the forecast period, Australia will have the largest LNG export nameplate capacity, 117.8 bcm per year, and the United States will become the second-largest with 106.7 bcm per year, slightly above Qatar with 104.9 bcm per year. These three big LNG export countries will make up half of the global total LNG export capacity of 650 bcm per year by the end of 2022, and the picture of future LNG trade in the world will be affected by these big LNG export countries located in Oceania, North America and the Middle East.

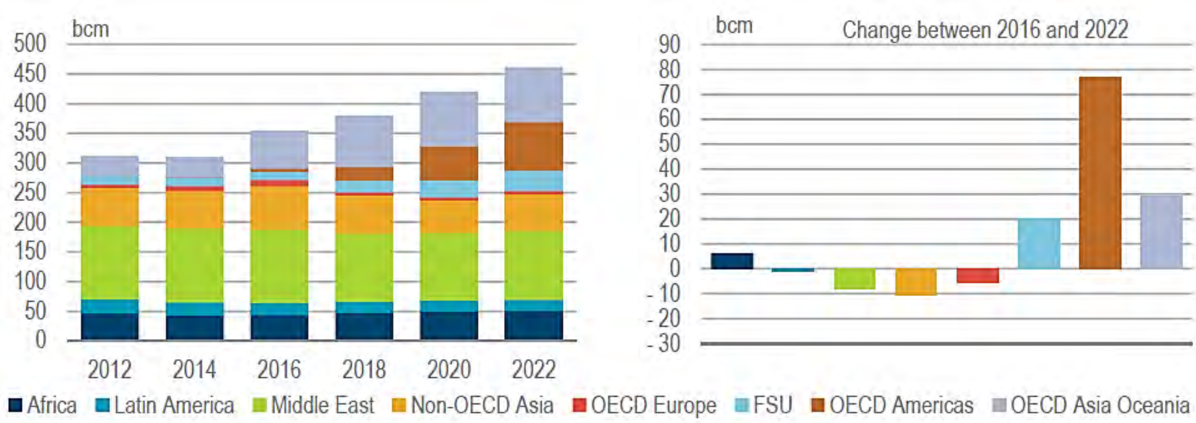
Figure 20 – LNG export capacity, 2016-22



Source: IEA (2017a)

LNG export nameplate capacity of 650 bcm by 2022 is much higher than the 460 bcm of forecast demand (see Figure 21 and Map 6). While some LNG export plants will be unavailable due to feed-gas issues and security problems, available export capacity will be more than the expected demand, and the highest surplus is expected by 2020 and then will shrink towards the end of forecast period. Across the LNG export side, it is worth highlighting the role of the new liquefaction projects, in particular those in the United States, giving destination flexibility. The expiring contracts in many existing liquefaction projects will reduce utilisation, especially in those with higher exposure to spot sales. The role of portfolio players is crucial to unlock new demand, and their market power with their aggregated volumes should not be underestimated.

Figure 21 – World LNG exports by region, 2012-22



Source: IEA (2017a)

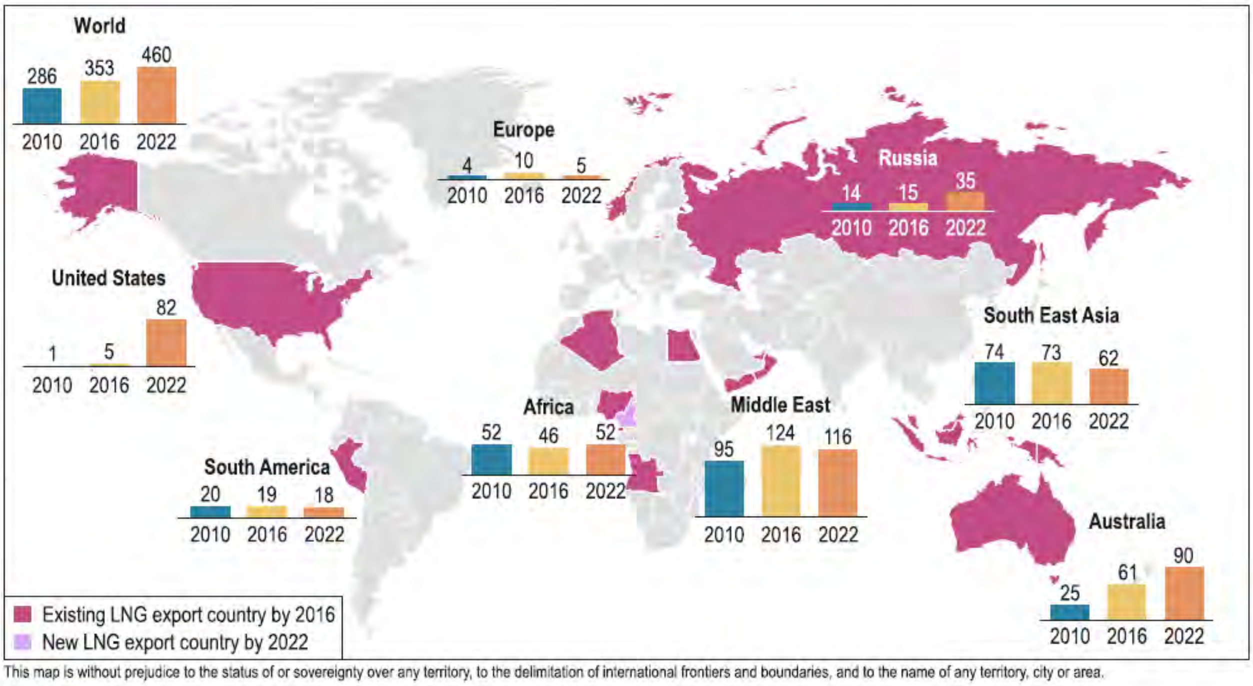
Russia, Algeria, the United Arab Emirates and Qatar were classified as flexible supply sources in IEA's Global Gas Security Review 2016 (9). Throughout the forecast period, all of these exporters should increase spare capacity, uncommitted to term contracts. Hence, they should be a reliable source of production flexibility in case demand or supply shocks occur.

The Latin America, Middle East and OECD Europe regions will experience a slight decrease in LNG exports by the end of the forecast period, falling by around 6% from 2016. In Latin America, Peruvian exports remain flat around 5 bcm, but overall LNG exports from this region will decrease because of the drop of LNG export volumes in Trinidad and Tobago due to the lack of feed gas. Exports from Norway will decrease slightly by 2022.

In the case of Africa, LNG exports from Nigeria and Equatorial Guinea will remain relatively flat, and LNG exports from Angola and Cameroon will be concentrated in the second half of the forecast period. LNG export from Algeria will decrease due to the expiration of long-term contracts. This happens precisely when the market faces the largest glut, and it may struggle to sell uncontracted LNG in the market.

OECD Americas will see a huge increase of LNG exports, with an additional 77 bcm by 2022, coming mainly from United States as a result of the shale gas boom. OECD Asia Oceania exports will grow remarkably by around 30 bcm and reach 90 bcm in 2022, coming from the new projects in Australia. Another 20 bcm of exports will be sourced from Russia on top of around 15 bcm in 2016. The highest decrease in LNG exports is coming from the non-OECD Asia region, where there will be a drop of around 10 bcm in 2022 from around 75 bcm in 2016. Expiring contracts in Malaysia that have Japan as the destination might not be renewed fully, taking into account the over-contracted position of Japan, and Malaysia might have to find new destinations. Long-standing feed-gas issues in Indonesia account for the majority of the remaining decrease in the region.

Map 6 – World LNG exports by region, 2012-22



Source: IEA (2017a)

United States

The United States, which has 14 bcm of capacity at the time of writing, is expected to rise to 107 bcm by 2022. New facilities will open at Cameron, Corpus Christi, Dominion Cove Point, Elba Island and Freeport and new trains are being added at Sabine Pass. The United States began exports in 2016, exporting nearly 5 bcm mostly to Mexico, South America and Asia. These exports are expected to soar to 82 bcm by 2022.

Australia

Australia is already the second largest exporter of LNG, with 89 bcm of capacity of which 32 bcm was added in 2016. The third train of the Gorgon facility started operations in March 2017, making Gorgon at 21.2 bcm, one of the largest facilities in the world. New facilities at Ichthys, Prelude and Wheatstone will increase capacity to 118 bcm by 2018 to move Australia ahead of Qatar. LNG exports, 61 bcm in 2016, are set to grow to 90 bcm by 2022.

Russia

Russia is expanding its exporting capacity from up to around 40 bcm by the end of the forecast period, starting the Yamal project on top of the existing Sakhalin II liquefaction facility, which holds 15 bcm of LNG export capacity, and will become the world´s sixth-largest LNG exporter just behind Indonesia and Malaysia. Flexibility will be another advantage of Russia's LNG in terms of both volume and destination. Existing contractual commitments with off-takers will leave room for 8 bcm of LNG exports, which would be offered on spot or short-term basis, or even being secured under long-term contracts. Moreover, the majority of output from the Yamal project is taken up by portfolio players such as Total and will enjoy destination flexibility.

Algeria

Algeria currently holds 38 bcm of LNG export capacity, but some upstream production issues constrain its export capacity. As a result, long-term contracted volumes are limited to 20 bcm and 10 bcm of the contracted volumes will expire by the end of 2019. Although the extension or renewal of some of these contracts is possible, given the limited availability of upstream production and the expected oversupply situation in the global LNG market, Algeria might prioritise pipeline exports instead of pursuing the contracts' renewal.

In its LNG export strategy, Algeria is focusing on the Mediterranean region. Amid a relatively weak LNG demand in Asia and Europe, Sonatrach has been increasing exports to Mediterranean countries such as Turkey, Egypt and Jordan during the recent years. At the end of last year, Sonatrach signed a co-operation agreement with the state-owned company of Turkey, Botas, aiming to strengthen its position in the regional markets, illustrating the increasing importance of the Turkish market. In 2000, 12% of all exported Algerian LNG volumes went to Turkey, and currently, around 25% of Algeria's LNG reaches the regasification facilities at the Turkish coast, delivering around 4 bcm per year based on a long-term contract that will expire in 2020. Turkey's LNG imports might decline due to pipeline imports via Turkish Stream in the future.

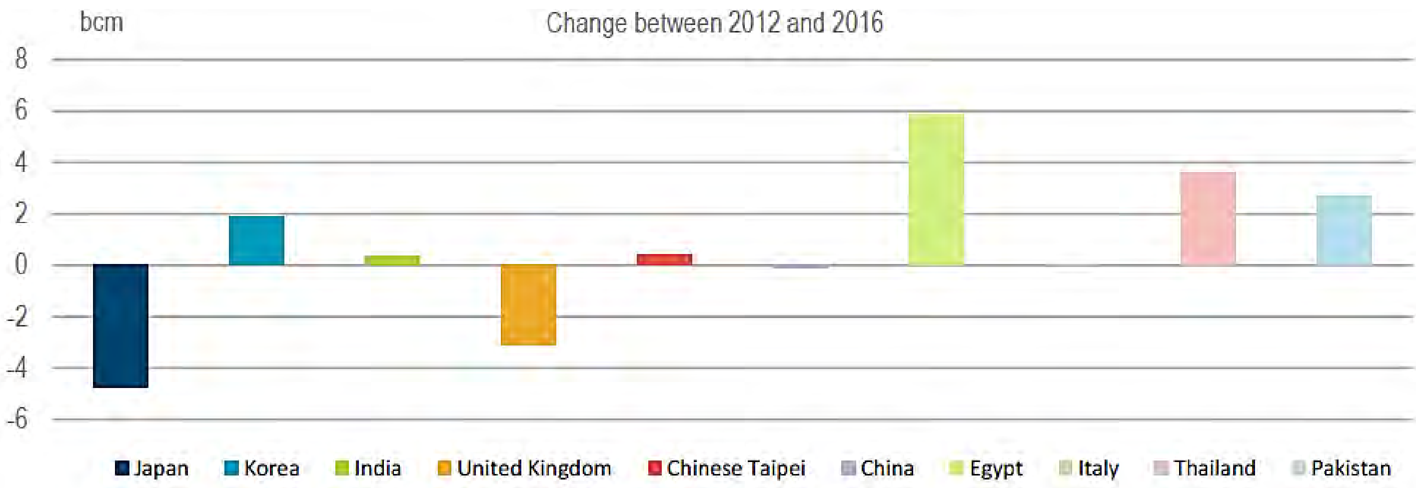
United Arab Emirates

The United Arab Emirates exports 80% of its LNG volumes, 8 bcm per year, under a long-term agreement with Japanese importer JERA, formerly TEPCO, and 20% on a spot basis. The existing 6.4 bcm per year long-term contract with JERA will expire by the end of 2019. Given the expected over-contracted situation of Japan, renewal or extension of the contract might come into question. In a context of oversupply, it will face big LNG sales competition, but once existing LNG export facilities are fully amortised, it could presumably offer competitive LNG sales options among the LNG exporters, assuming feed-gas supplies are available.

Qatar

Qatar is the world's largest LNG exporter with a liquefaction nameplate capacity of 105 bcm. In 2016, Qatar LNG exports were almost 105 bcm, which represented roughly a third of global LNG trade and nearly 100% utilisation rate of its nominal capacity, and are estimated to be around 100 bcm over the forecasted period. 96% of its capacity is committed under term contract and almost 30% of these volumes have flexible destination clauses. This has allowed Qatar to become a reliable supply source of flexible LNG to the spot market beyond its term commitments. In addition, the expiration of several contracts in the coming years, mainly destined to Japan and the United Kingdom, will probably result in increased volume flexibility. With the existing contractual commitments, Qatar will have around 15 bcm of uncontracted volumes by 2022. To maintain its position as the major LNG exporter, which has already been announced by its government, the country has reoriented its strategy towards new LNG importers. Figure 22 shows a major shift in Qatar LNG exports over the period 2012-2016 from traditional LNG buyers like Japan or United Kingdom towards new LNG import countries like Egypt, Thailand and Pakistan. This change has allowed Qatar to maintain its LNG export volumes over the period while LNG exports to traditional buyers decreased.

Figure 22 – Change of LNG export volumes from Qatar by countries, 2012-16

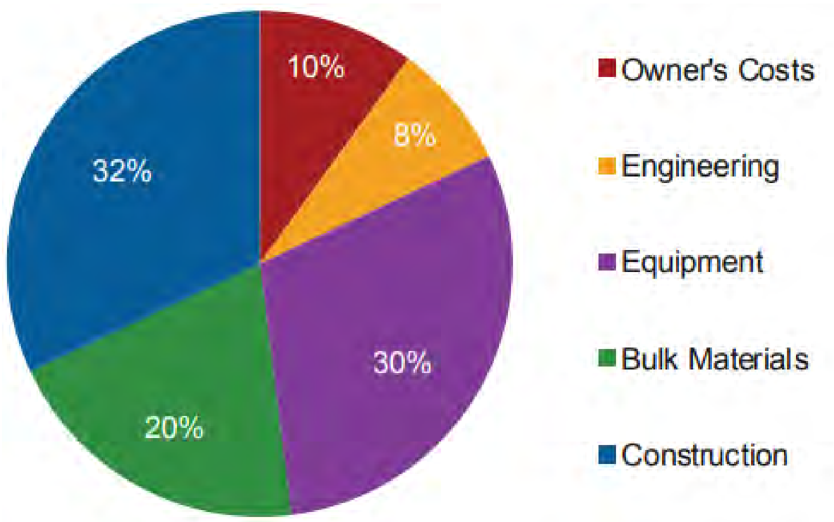


Source: IEA (2017a)

Regasification Terminals

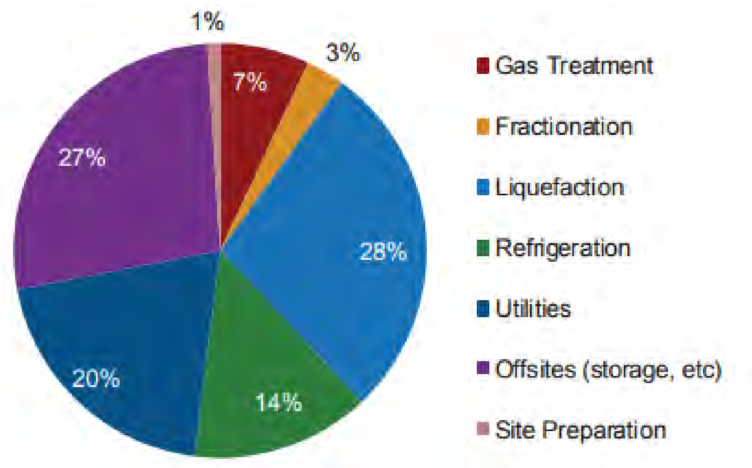
Global regasification capacity increased to 776.8 mtpa by the end of 2016 and 794.6 mtpa by the end of January 2017, primarily supported by additional capacity coming online in established markets such as China, Japan, France, India, Turkey, and South Korea. This stands in contrast with 2015, when capacity was driven by floating regasification projects in emerging markets: Egypt, Jordan, and Pakistan. The expansion of new markets slowed in 2016, as capacity was only added in Jamaica - both Colombia and Malta received their initial LNG cargoes in 2017. An additional 90.4 mtpa of capacity were under construction as of January 2017. A combined eleven projects are under construction in China and India, countries that displayed the strongest LNG demand growth in 2016. New entrants are also set to complete regasification projects in the coming years, including the Philippines, Bahrain, and Russia (Kaliningrad). In the appendix of this study, there are detailed tables including existing regasification and liquefaction terminals in the Mediterranean Sea.

Figure 23 – Average Cost Breakdown of Liquefaction Project by Construction Component



Source: IGU

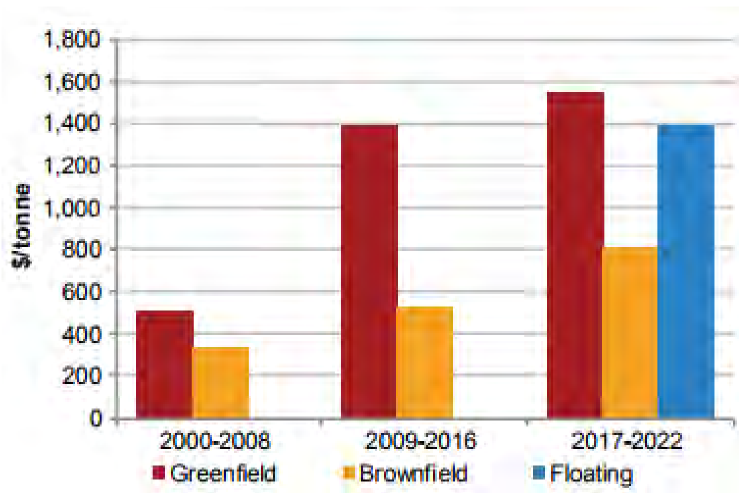
Figure 24 – Average Cost Breakdown of Liquefaction Project by Expense Category



Source: IGU

Cost escalation has been considerable, with several projects reporting cost overruns in the range of approximately 30% to 50% relative to estimates at FID. Unit costs[23] for liquefaction plants increased from an average of \$413/tonne in the 2000-2008 period to \$987/tonne from 2009-2016. Over the same periods, greenfield projects increased from \$507/tonne to \$1,389/tonne, while brownfield projects only increased to \$532/tonne, up from \$329/tonne (see Figure 25). The commencement of operations at the first FLNG projects beginning in 2017 will likely provide additional clarity on FLNG costs.

Figure 25 – Average Liquefaction Unit Costs in \$/tonne (real 2014) by Project Type, 2000-2022

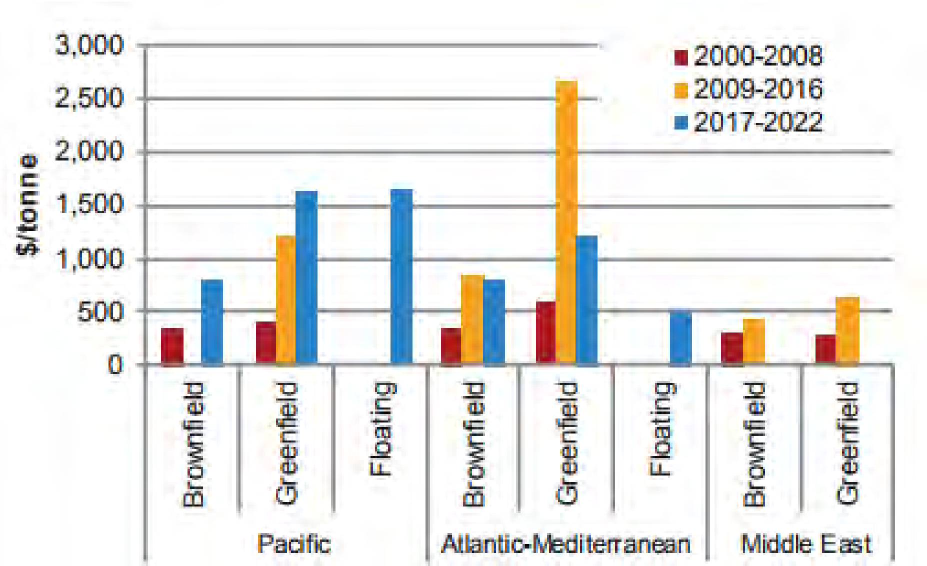


Source: IGU

[23] All unit costs are in real 2014 dollars.

Middle Eastern projects generally remained low-cost in the 2009-2016 period, averaging $452/tonne, largely due to the lower cost of brownfield expansions in Qatar. Conversely, projects in both the Pacific and Atlantic Basins experienced significantly higher costs during 2009-2016 relative to 2000-2008 (see Figure 26). The Pacific Basin had the highest increases, with per unit liquefaction costs nearly quadrupling from $347/tonne to $1,373/tonne between the same periods due in part to cost escalation at some projects. The average unit liquefaction cost for Atlantic Basin LNG projects rose to $1,221/tonne from 2009-2016, compared to $461/tonne from 2000-2008. Although ultimate FLNG costs are not yet clear, several FLNG projects based on vessel conversion schemes have had lower announced cost estimates relative to onshore greenfield and FLNG newbuild proposals.

Figure 26 – Average Liquefaction Unit Costs in $/tonne (real 2014) by Basin and Project Type, 2000-2022



Source: IGU

Based on cost announcements and the advantages associated with existing infrastructure, brownfield projects will generally be competitive with greenfield developments in terms of unit costs of liquefaction capacity. Five of the six liquefaction projects under construction in the US are brownfield projects associated with existing regasification terminals. Unit costs for these continental US brownfield projects average $807/tonne, well below the $1,508/tonne associated with under-construction greenfield projects globally.

Apart from high liquefaction costs, greenfield projects proposed in Western Canada and Alaska require lengthy (300 miles or more) pipeline infrastructure. Integrated Western

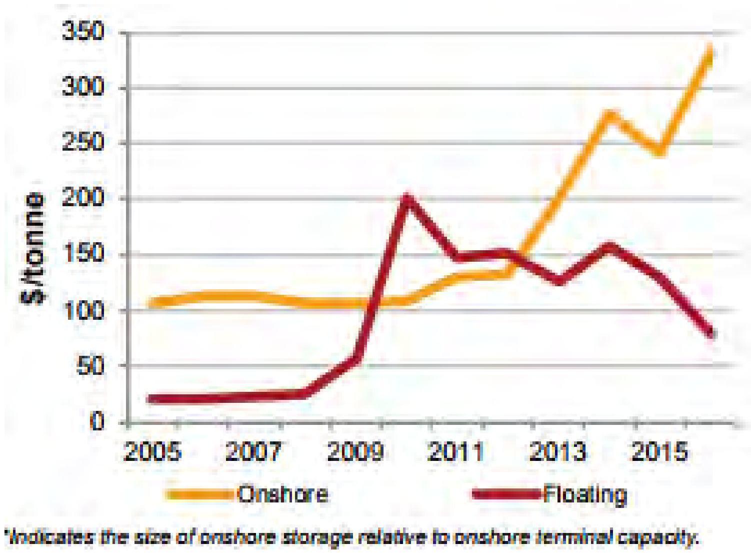
Canadian projects have announced cost estimates of up to $40 billion, while in Alaska the estimate was revised downward in 2016 to approximately $45 billion from $45-65 billion previously.

CAPEX costs for new receiving terminals have risen significantly over the last few years, specifically onshore terminals, after experiencing a period of relative steadiness between 2006 and 2012. FSRU CAPEX has remained fairly steady with a slight decline in recent years. FSRUs had experienced a large jump in 2009 and 2010 as the active number of floating terminals increased from four to ten; some of which were capital intensive projects. Regasification CAPEX figures are typically composed of costs associated with vessel berthing, storage tanks, regasification equipment, send-out pipelines, and metering of new facilities.

In 2016, the weighted average unit cost of onshore regasification capacity that came online during the year was $334/tonne (based on a three-year moving average), which is significantly higher than the 2015 average ($242/tonne), as the Hitachi (Japan) and Swinoujscie (Poland) projects both began operations in 2016 (see Figure 27). The rise in onshore regasification costs is closely associated with the trend of increased LNG storage capacity. As countries – mainly in high-demand regions like Asia and Asia Pacific – add larger storage tanks to allow for higher imports and greater supply stability, the storage capacity size per unit of regasification capacity has increased. However, several new onshore terminals with smaller storage units are expected online in 2017 and 2018, bringing down overall costs. CAPEX for onshore capacity under construction are set to fall to $212/tonne in 2017 and $285/tonne in 2018, if all developing projects come online on time. However, a number of proposed projects that may soon reach construction milestones have higher CAPEX, which could ultimately bring these averages higher. Nonetheless, these figures vary significantly on a caseby-case basis, often depending on country-specific factors, including associated infrastructure development requirements.

Given that floating terminals require relatively limited infrastructure development in order to reach operations, CAPEX for FSRUs has been generally lower than onshore proposals. However, typically OPEX is higher for floating receiving terminals given that vessel charters are considered an OPEX cost.

Figure 27 – Regasification Costs based on Project Start Dates, 2005–2016



Source: IGU

New floating terminals' CAPEX have remained roughly steady over the past three years, declining from a high of $158/tonne in 2014.5 In 2016, the weighted average unit cost of floating regasification based on a three-year moving average was $78/tonne. A rise in FSRU conversions, which can be brought into operations at a lower cost than new-build vessels, will be a factor in reducing average floating terminal CAPEX. However, this figure is slightly skewed due to limited reporting of CAPEX figures for recently completed floating terminals. As of January 2017, there were six FSRUs considered to be under construction and seven forthcoming FSRU projects that have selected an FSRU provider. Four of these projects have notably high CAPEX, particularly the Uruguay, Bahrain, Brazil, and Chile proposals, indicating that average FSRU costs could be rising moving forward. As with onshore terminals, larger vessels – and thus greater storage and send-out capacity – have accompanied higher CAPEX. Still, there is generally less variation in overall CAPEX for floating terminals than for onshore facilities, which is partly a reflection of fewer differences in capacity and storage size for vessel-based terminal solutions.

5. Existing and planned gas infrastructure projects in SE Europe

The SEE region is an important geostrategic energy corridor and hence there is a strong need for new energy projects in order to ensure energy security and energy transit towards and across Europe. In spite of the strong interest by several SEE countries to invest in energy projects, the implementation has proved to progress very slowly, since no major regionally significant projects in the oil and gas sector were completed during the last decade. In most

SEE countries, regional energy cooperation has been perceived as a necessary part of the European integration process. At the beginning of the present decade, the main targets of the EU energy policy were incorporated in the long term strategies of SEE countries. The focus has been redirected towards modernisation of existing energy facilities and construction of new ones, improvement of energy efficiency and increasing share of renewable energy sources.

(a) Cross-border main gas pipelines in SE Europe

I. TAP-TANAP System

Trans Anatolian Pipeline (TANAP)

The Trans Anatolian Pipeline (TANAP) is a joint Azeri-Turkish project and aims to bring Azeri gas to the European edge of Turkey, where it will be connected with the 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 2018 and will cost about $10 billion. Turkey will receive gas in 2018 and after completing the construction of Trans-Adriatic Pipeline (TAP), extra gas will be delivered to Europe by early 2020. Currently, the shareholders of TANAP are: the State Oil Company of Azerbaijan (SOCAR) – 58%, Botas – 30% and BP – 12%.

The 1,850 km pipeline, construction of which started in 2015, will run from the Georgian-Turkish borders and up to the Turkish-Greek borders. The pipeline, which will transfer gas from Azerbaijan to Turkish border across Georgia, is the South Caucasus Pipeline, which is being expanded and has a different ownership structure, compared to TANAP. The initial transport capacity of TANAP will be 16 bcm of gas per annum, 6 bcm of which will be consumed by the Turkish consumers and 10 bcm will be delivered to European countries via TAP. Afterwards, TANAP's total capacity is planned to increase to 23 bcm by 2023 and to 31 bcm by 2026. The gas pipeline is expected to be put into operation in 2019 and will be devoted from the beginning to gas produced from the Shah-Deniz Phase-2 field.

Map 7 – TAP-TANAP System

Source: TAP AG

The construction of the TANAP's 19 km underwater section in the Marmara Sea commenced on September 23, 2017. TANAP's construction is currently completed by 82% and as Turkey's Minister of Energy and Natural Resources Berat Albayrak announced in November 2017, the project will be 94% completed by the end of this year.

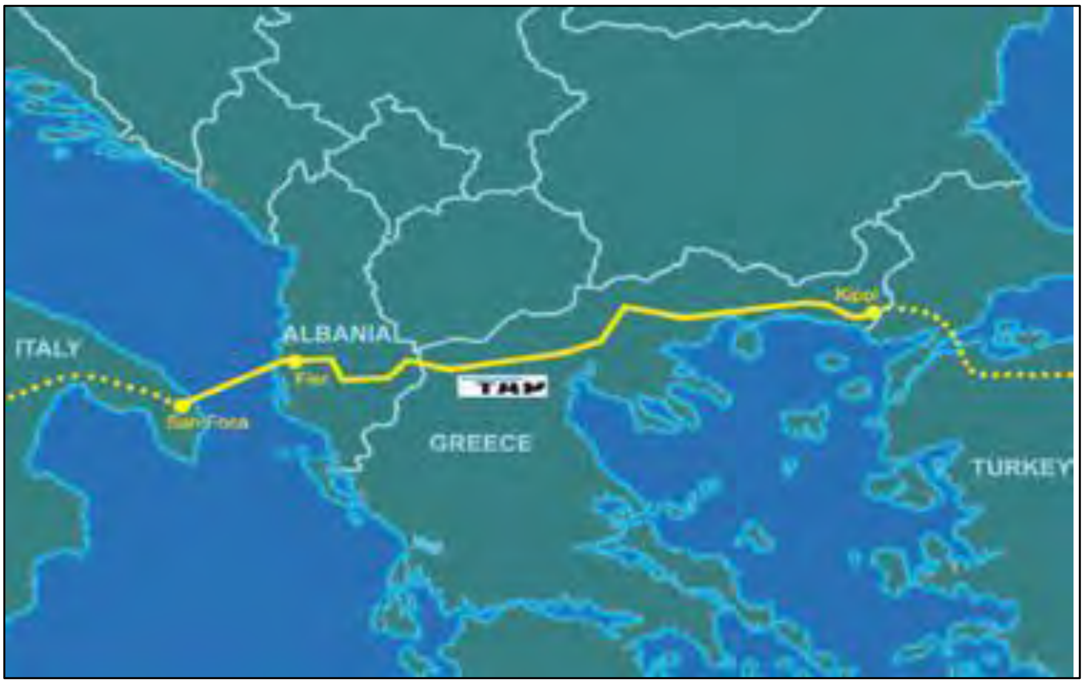
Trans Adriatic Pipeline (TAP)

Trans Adriatic Pipeline (TAP) was selected by the Shah Deniz consortium in order to carry gas to Europe from Turkey's western border. TAP will connect existing and planned gas grids in Southeast Europe with gas systems in Western Europe via Greece, Albania, the Adriatic Sea and Italy. Therefore, the pipeline will give Europe better access to major gas reserves located in the Caspian region.

The pipeline, which is expected to be operational in 2020, is designed with an initial 10 bcm/year 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 TAP construction will cost about $5.3 billion. In February 13, 2013, the governments of Greece, Italy and Albania confirmed their full support and commitment to the TAP project by signing in Athens (Greece) a tri-lateral intergovernmental agreement.

Furthermore, TAP's route can facilitate gas supply to several South Eastern European countries, including, among others, Albania, Bulgaria, Bosnia and Herzegovina, Montenegro and Croatia. TAP's landfall in Italy provides multiple opportunities for further transport of Caspian gas to some of the largest European markets such as Germany, France, the UK, Switzerland and Austria. TAP’s shareholding is comprised of BP (20%), SOCAR (20%), Snam S.p.A (20%), Fluxys (19%), Enagás (16%) and Axpo (5%).

Map 8 – TAP Pipeline



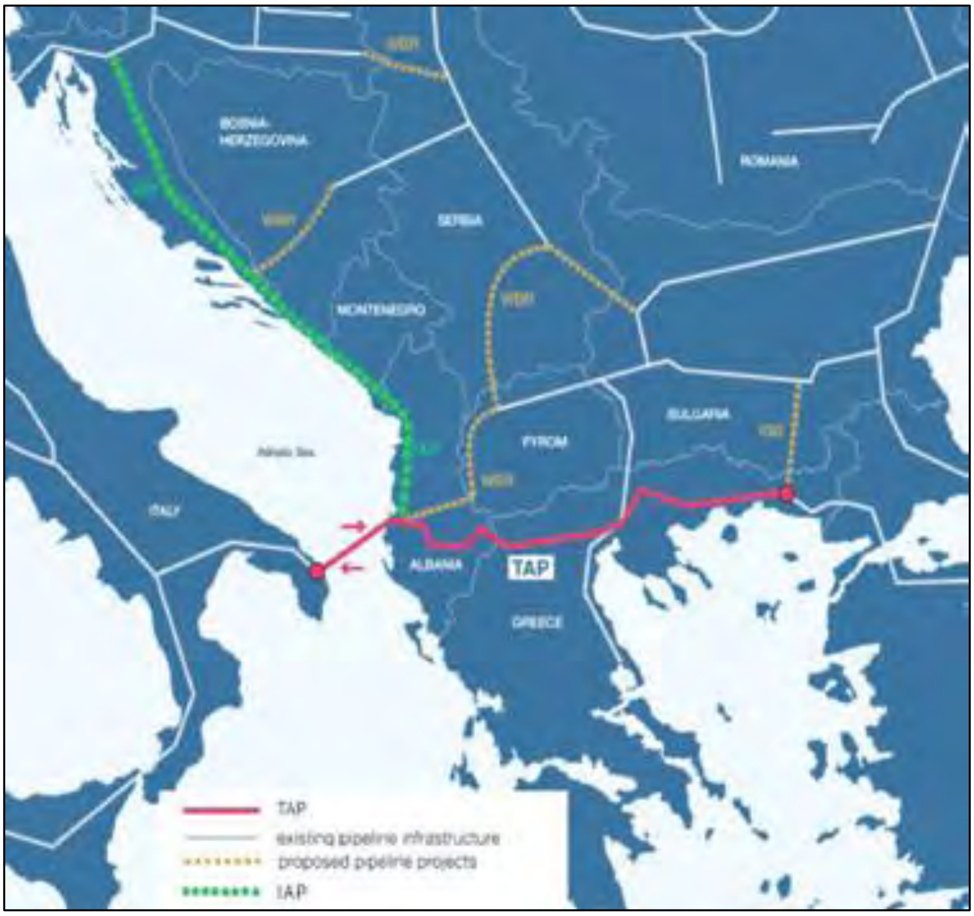
Source: TAP AG

Construction of the underwater section of the TAP will begin in 2019, according to the project managing director Luca Schieppati, who was quoted by the Azeri news agency Trend in September 2017. The eastern terminal of the underwater TAP pipeline will be near the Albanian city of Fier, with its deepest segment some 820 meters below the sea's surface. "We will have prepared 85% of the ground in Greece and Albanian by the end of 2017, while 70% of the pipes will have been placed and covered," Schieppati said.

II. Ionian-Adriatic gas pipeline (IAP)

The Ionian-Adriatic gas pipeline (IAP) project, which is currently at planning stage, would connect the Croatian, Montenegrin, Bosnian and Albanian gas transmission systems to the TAP to form an integral part of the Southern Gas Corridor and would open up a supply route to the EU for Azeri gas from the Caspian Sea. It is to be 511 km long and will have a transport capacity of 5 bcm per year, which could be increased if it is equipped with a reverse flow system.

Map 9 – IAP Pipeline



Source: TAP AG

Building permits for the Croatian section of the Ionian-Adriatic Pipeline are expected to be obtained during 2019, a source in Croatian Plinacro Ltd. natural gas transmission system operator announced in September 2017. Earlier, the company announced that a building permit has been obtained for the first phase of Split-Ploce section of IAP in Croatia. As for the second and third phases, the source noted that the process of construction of the Split-Ploce section of IAP is in permitting phase. Memorandum of Understanding and Cooperation signed in August 2016 by the countries involved in the project confirmed the joint initiative for the development of the relevant project and established the operative body for the Ionian-Adriatic Pipeline (Project Management Unit), which adopted an action plan for the project development in 2017.

This operative body consists of the representatives of the relevant Ministries of Croatia, Montenegro, Albania and Bosnia and Herzegovina as well as the representatives of companies which are the operators of the transmission systems in the mentioned countries

(Plinacro, Montenegro Bonus, Albpetrol and BH-Gas) and the representative of the Azerbaijan's state oil company SOCAR.

III. Turkish Stream

The Turkish Stream is an under construction gas pipeline that will connect Russia with Turkey across the Black Sea, which will substitute the now defunct South Stream. The proposal was first announced by Russian president Vladimir Putin on December 1, 2014 during his official visit to Turkey. Landfall will be near the village of Kiyikoy in Turkey's European sector, and a delivery hub for Turkish consumers will be close to the town of Luleburgaz (see Map 10).

The pipeline will terminate in the Turkish-Greek borders in the area of Ipsila. The first stretch will be intended for the Turkish market and the second will supply natural gas to countries of South and Southeast Europe. Each stretch will have a capacity of 15.75 bcm of natural gas annually. The pipeline is expected to annually pump 31.5 bcm of natural gas. Gazprom suggested the EU (i.e. the European client companies of Gazprom) should build its own link from the as-yet unbuilt gas hub at the Turkish-Greek borders to transit some 50 bcm via the new route to various European destinations. A new pipeline will need to be built, which will cross North Greece and from there via the Adriatic Sea to Italy.

Map 10 – Turkish Stream Pipeline

Source: Gazprom

The construction of this pipeline initially raised concerns, mainly because Russian-Turkish relations deteriorated over the downing of the Russian warplane at the Syrian border on November 24, 2015. However, after Russia received an apology for the downing of its warplane from Turkish President Recep Tayyip Erdogan in June 2016, Gazprom was ready to resume talks with Ankara on the construction of the Turkish Stream.

Consequently, both countries signed on October 10, 2016 in Istanbul the Turkish Stream natural gas project. More specifically, Turkish energy minister Berat Albayrak and his Russian counterpart Alexander Novak agreed the terms on the sidelines of the World Energy Congress, which was held in Istanbul from October 9-13, 2016. After the signing ceremony, Turkey's president Recep Tayyip Erdogan said that the deal will help to normalize strategic relations between the two countries.

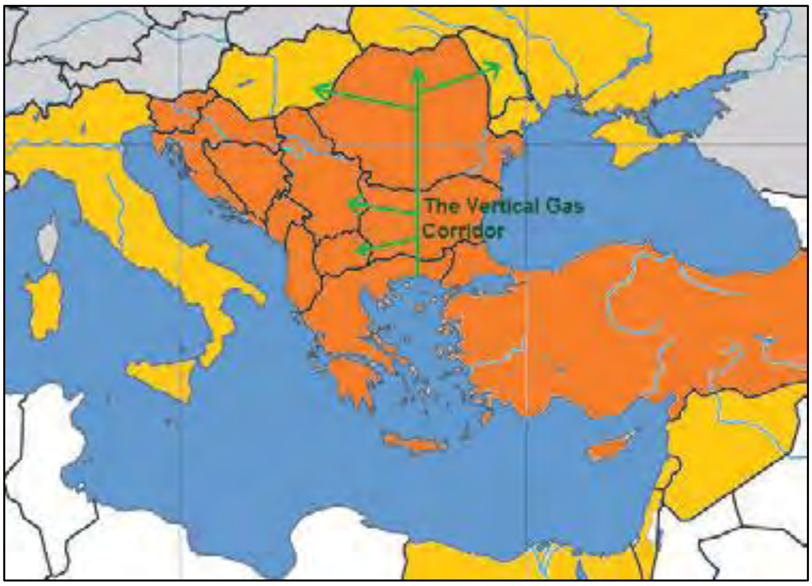
According to latest information, Turkey’s Ministry of Environment and Urbanization has approved the Environmental Impact Assessment (EIA) for the offshore section of the Turkish Stream. Gazprom launched the construction of the Turkish Stream gas pipeline’s offshore section near the Russian coast of the Black Sea on May 7, 2017. The company has already built around 300 kilometers of the Black Sea segment of the Turkish Stream gas pipeline. The first line is scheduled for completion in March 2018 and the second in 2019.

IV. The Vertical Corridor

The Greek national grid could be a starting point of a gas system, which will carry significant gas quantities in a vertical axis (south to north) and in a constant flow to Bulgaria and Romania and from there to a number of countries such as Hungary, Serbia, Moldavia and others. The above idea, which is known as the Vertical Corridor and it is supplementary to the South Corridor, has been adopted by the three governments of Greece, Bulgaria and Romania and will contribute significantly to the gas interconnectivity in SE and Central Europe. The Vertical Corridor is emerging as a project to fill the gap of interconnections needed to link SE Europe’s isolated markets and provide reverse-flow options for existing routes.

The Vertical Corridor concept will not be a pipeline project as far as the other south corridor projects are concerned but a gas system that will connect the existing national gas grids and other gas infrastructure in order to secure energy security and ensure liquidity. Such a gas system will be an important corridor from South to North, fully coordinated to the European energy policy. Initially, the Vertical Corridor will amount some 3-5 bcm per year starting from the Greek national grid and later could transfer some 8 bcm.

Map 11 – The Vertical Corridor



Source: IENE (2015)[24]

According to latest information, Greece's Gas Transmission System Operator (DESFA), along with its counterpart Operators in Bulgaria, Romania, Hungary and, recently added, Ukraine created two new working groups for the implementation of the Vertical Gas Corridor. The meeting was on senior management level and took place in the sidelines of the 4th High Level Group meeting of the Central and South-Eastern European Gas Connectivity (CESEC) in Bucharest (Romania) on September 28, 2017. In July 19, 2017, Greek (DESFA), Bulgarian (Bulgartransgaz), Romanian (Transgaz) and Hungarian (FGSZ) Gas Transmission Operators and ICGB AD consortium, the contractor for the Greece-Bulgarian Interconnector (IGB) pipeline project, signed a Memorandum of Understanding (MoU) on the Vertical Gas Corridor project in Bucharest, while on September 9, 2016, Greek (DESFA), Bulgarian (Bulgartransgaz), Romanian (Transgaz) and Ukrainian (Uktransgaz) Gas Transmission Operators signed a relevant MoU, respectively.

V. The East Med Pipeline (East Med)

The Eastern Mediterranean (East Med) pipeline project is an offshore/onshore gas pipeline that will directly connect the East Mediterranean gas resources to the European gas system.

[24] IENE (2015), "The "Vertical Corridor": From the Aegean to the Baltic", M26, http://www.iene.eu/articlefiles/the%20vertical%20corridor%20-%20from%20the%20aegean%20to%20the%20baltic.pdf

The pipeline will transport up to 15 bcm of gas from the offshore gas reserves in the Levantine Basin (Cyprus and Israel) and the potential reserves of Greece to the Greek gas system and the Italian gas system via the aforementioned Poseidon pipeline, according to DEPA.

The promoter of this pipeline is IGI-Poseidon SA, a Greek company equally owned by DEPA and Edison. The company is in charge of the development of other projects in the framework of the Southern Corridor region, namely the Poseidon pipeline and the Interconnector Greece-Bulgaria (IGB).

Map 12 – The East Med pipeline and possible connections

Source: Edison

The East Med pipeline project comprises the following sections:

- about 150km offshore pipeline from the Levantine Basin to Cyprus
- about 650km offshore pipeline from Cyprus to Crete
- about 400km offshore pipeline from Crete to Peloponnese
- about 500km onshore pipeline on the Greek territory up to the connection with Poseidon pipeline in the Thesprotia region

At first glance, the biggest obstacle to the construction of the East Med pipeline is its technical viability. Practical challenges abound. On the approach to Crete, for instance, there is a stretch of about 10 km where the depth is quite high, which could cause construction problems. However, the companies involved are optimistic that technology will advance sufficiently to enable the pipeline to be built. Greece's DEPA describes the project as "technically and economically feasible," according to studies it has conducted. To bolster its case, DEPA notes the success of the Medgaz pipeline, which runs between Algeria and Spain. Israel energy minister Yuval Steinitz, too, has attempted to ease fears about construction issues and suggests that East Med can be completed by 2025.

Preliminary deep-sea survey work is being planned around Cyprus and Crete to determine the pipeline's route. On December 5, 2017, Greece, Cyprus, Italy and Israel signed a memorandum of understanding for constructing the project, which will allow the transportation of newly discovered Cypriot and Israeli gas reserves to mainland Europe.

Greece's Energy Minister Mr. Giorgos Stathakis said that the East Med pipeline is "technically and economically viable", enjoys the support of all the other countries involved as well as the European Commission and would allow Israel and Cyprus to transport their proven hydrocarbon reserves as well as Greece's potential reserves to the European market. Studies conducted so far indicate that the project's construction cost could reach €6 billion, while it is currently classified as a Project of Common Interest (PCI) by the EU.

VI. Bulgaria-Romania-Hungary-Austria (BRUA) Corridor

The BRUA corridor is a set of reverse-flow gas interconnectors between Bulgaria, Romania, Hungary and Austria. It is expected to have a 1.5 bcm/y transport capacity towards Bulgaria and 4.4 bcm per year towards Hungary. An additional pipeline is set to be built in order to bring offshore gas onto the Romanian national grid and then onwards through BRUA. Though with a small capacity, BRUA's merit is that it can deliver gas from both TAP (once it is operational) and from the Austrian Baumgarten gas hub, while at the same time, it uses the existing gas infrastructure, leaving only additional compressor stations and some pipeline segments to be built.

Map 13 – BRUA Corridor

Source: European Commission

There has been some controversy over the future of the BRUA corridor. The project was thrown into doubt in July 2017 after Romania's TSO Transgaz said the link would no longer cross Hungary because Budapest was looking to send gas onward to countries other than Austria. However, the parties involved reaffirmed their commitment to the project in its original form at the CESEC meeting on September 28, putting it back on track. More specifically, Bulgaria, Romania, Hungary and Austria signed a memorandum of understanding to proceed with implementation of BRUA gas link project. Under the memorandum, all countries have agreed on a reverse-flow gas interconnection. Romania has issued a building permit for the BRUA project on its territory and has conducted procedures for assigning the construction works. The pipeline will have a total length of 528 km.

VII. Eastring Pipeline

Eastring pipeline aims to connect existing gas infrastructure in Slovakia, Ukraine or Hungary, Romania and Bulgaria through a new reverse-flow pipeline. It has largely the same merits as BRUA in terms of gas sources, albeit a different route and significantly larger capacity – expected to reach 20 bcm at first stage and 40 bcm after its final stage is completed.

Map 14 – Eastring pipeline

Source: Natural Gas Europe

Slovak gas transmission system operator Eustream signed on September 7, 2017, the contract on the feasibility study for the Eastring. The contract was awarded to Hungarian engineering and consultancy company Euroil. Following the signing of the contract, the works on the feasibility study were initiated on September 5 in Bratislava. The main purpose of the feasibility study is to define all necessary technical, economical, financial and environmental details of the future pipeline including optimal routing as well as to carry on the in-depth market testing. 50% of the eligible costs of the feasibility study will be funded by the European Commission under the Connecting Europe Facility fund. The feasibility study will be completed in June 2018 and its outcomes will serve as the basis for next decisions on the project parameters. Eastring pipeline is the EU’s Project of Common Interest (PCI) that will serve as an interconnection between Western European liquid hubs and the Balkan region.

Table 17 – Major Gas Pipeline Projects in SE Europe

Project	Shareholders	Distance	Cost	Capacity	Status
TAP	BP (20%), SOCAR (20%), Snam S.p.A (20%), Fluxys (19%), Enagás (16%), and Axpo (5%)	878 km	$5.3 billion	10-20 bcm/y	Under construction
TANAP	SOCAR (80%), Botas (20%)	1,850 km	$10 billion	16-24 bcm/y	Under construction
Ionian-Adriatic gas Pipeline (IAP)	Plinacro, BH-Gas, Governments of Montenegro and Albania	511 km	€618 million	5 bcm/y	Under study
Turkish Stream	Gazprom, BOTAS	1,100 km	$11.4 billion	63 bcm/y	Under construction
East Med Pipeline	DEPA (50%) and Edison (50%)	1,880 km	$7 billion	8 bcm/y	Under study
Bulgaria-Romania-Hungary-Austria (BRUA) Corridor	-	500 km	€500 billion	6 bcm/y	Under consideration
Eastring Pipeline	Eustream	832-1,015 km	-	20-40 bcm/y	Under consideration

Sources: IENE, websites of involved energy companies

Gas Interconnectors in SE Europe

According to the current planning by the TSOs of Greece, Bulgaria, Romania and Serbia, they aim to expand their gas infrastructure putting emphasis on the construction of gas interconnectors, in order to avoid future gas disruptions and increase their energy security. When ready, this network of gas interconnectors will supply the region with additional natural gas quantities coming from the TAP pipeline, the liquefied natural gas terminal in Revithoussa (currently the only LNG terminal in Greece) and also from the FSRU terminal in Alexandroupolis.

Map 15 – Gas interconnections in SE Europe

Source: IENE

I. Interconnector Greece-Bulgaria (IGB)

The IGB project includes the construction of a cross-border and bi-directional gas pipeline about 182km long, connecting the Greek gas network in the area of Komotini with the Bulgarian gas network in the area of Stara Zagora. The annual capacity of the gas pipeline is foreseen to be up to 5 bcm, depending on interest from the market and the capacities of the neighbouring gas transmission systems. The IGB is strongly connected with the Southern Corridor and the Interconnector Turkey-Greece (ITG).

On December 10, 2015, Bulgaria’s state energy holding BEH and Greek-Italian joint venture ISI Poseidon signed a key investment deal for the implementation of this project. ICGB, the project company developing the gas interconnection Greece-Bulgaria, has said it expects to receive a building permit for the section of the pipeline on Greek territory no earlier than 2018. The first step in the process of obtaining a building permit will be a decision for exemption from the rules for tariff, ownership and access to third parties, expected to be adopted by the regulatory authorities of both countries in October 2017, and by the EU at the beginning of 2018. After that, the project has to obtain a licence for a transmission system operator, which is a condition for obtaining a building permit under Greek law. On

September 12, 2017, the Ministry of Regional Development and Public Works issued the construction permit for the interconnector on Bulgarian territory for the municipalities Stara Zagora, Radnevo and Opan, Region Stara Zagora, the municipalities Dimitrovgrad and Haskovo, region Haskovo and the municipalities Djebel, Kurdzhali, Momchilgrad and Kirkovo, Region Kurdzhali.

On November 8, 2017, the Call for tender for the "Selection of Owner's Engineer for the Construction of the Gas Interconnector Greece-Bulgaria" was sent for publication to the Registry of Public Procurement of Bulgaria's Public Procurement Agency. The Owner's Engineer will provide crucial assistance to ICGB for the implementation of the IGB project during the construction phase through to interconnector's commissioning, supporting the management of the major contracts. The estimated value of the public procurement is set as a total price of €8.45 million, excluding VAT. On December 13, 2017, ICGB announced the extension of the deadline for submission of offers for the aforementioned public procurement by January 15, 2018, amending the previous deadline, due to the increasing number of requests received at the office of the company. The first announced deadline was December 19, which was aligned with the legally established minimum deadline under the Public Procurement Act of 35 days.

As announced on December 8, 2017, ICGB launched public procurement for selection of supplier of IGB's line pipes. The scope of supply includes the production, inspection, testing, shipment, transportation to point of delivery and documentation requirements of these items in accordance to this specification. All other services related to the pipe installation and additional materials will be purchased via a parallel running tender for the EPC contractor, which will be announced in the beginning of 2018. The estimated value of the public procurement is €60 million. VAT exclusive and the term for implementation of the public procurement is 12 months as of the receipt of an assignment order according to the conditions specified in the Public Procurement Contract.

The planned gas pipeline is estimated to cost €220 million. The project company has secured a sovereign guarantee of €110 million under the annual state budget act, which could ensure loan financing under preferable conditions.

Map 16 – IGB route

Source: ICGB AD

II. Interconnector Turkey-Greece-Italy (ITGI)-Poseidon

A Memorandum of Understanding (MoU) was signed on February 24, 2016 to develop a gas pipeline project between Greece and Italy, enabling the realization of a southern route for Russian gas supply to Europe. The MoU was signed by the CEO of Gazprom Alexey Miller, the CEO of Italian Edison Marc Benayoun and the CEO of Greece's public gas corporation (DEPA) Theodoros Kitsakos. According to a Gazprom statement, the parties intend to use the works already performed by Edison and DEPA in relation to the ITGI Poseidon project. Poseidon was shelved years ago, when it became obvious that TAP was to become part of the Southern gas corridor, which aims to bring Azeri gas to Europe.

It also remains unclear whether Poseidon is a direct competitor of TAP for transporting Azeri gas, or if it is intended to be an additional route for Russian gas. "The development of intra-European gas transmission capacities is an important element in securing reliable supplies of gas, including Russian gas, to consumers across Europe," Miller was quoted as saying. The potential development of this new gas supply corridor will be pursued in full accordance and in compliance with EU legislations and regulations.

On September 19, 2017, the Turkish cabinet formally ratified an intergovernmental agreement with Greece allowing for the development of the ITGI pipeline project. The approved gas deal, which has been released in the country's official government gazette, brings at the forefront yet another forgotten pipeline route, apart from Turkish Stream, for the purposes of the transportation of Russian natural gas in the EU through the Southern

Gas Corridor. Also, it indicates Turkey's willingness to further enhance energy cooperation with Russia following progress on the Turkish Stream sub-sea construction.

Map 17 – ITGI-Poseidon route

Source: ITGI

III. Interconnector Greece-FYROM (IGF)

IGF is a planned gas interconnector that aims at the interconnection of natural gas transmission systems of Greece and FYROM. According to DESFA's Ten-Year Development Study[25], the project will enhance the diversification of FYROM's gas supply sources as the country is currently solely gas dependent from Trans Balkan Pipeline. Greece's Gas Transmission System Operator DESFA and FYROM's State Company for the exploitation of energy resources MER signed a Memorandum of Understanding for the project in October 2016.

IV. Interconnector Bulgaria-Romania (IBR)

In August 2011, Bulgaria commenced the construction of a gas interconnection with Romania. The gas interconnection was officially opened on November 11, 2016. The project cost about €24 million, €9 million of which came from EU funds, €11 million from Bulgaria, and the rest were 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.

[25] http://www.desfa.gr/wp-content/uploads/2017/07/f_%CE%9C%CE%95%CE%9B%CE%95%CE%A4%CE%97-%CE%91%CE%9D%CE%91%CE%A0%CE%A4%CE%A5%CE%9E%CE%97%CE%A3-%CE%95%CE%A3%CE%A6%CE%91-2018-2027_ENG.pdf

V. Interconnector Turkey-Bulgaria (ITB)

Bulgaria’s gas transmission and storage system operator Bulgartransgaz and Turkey’s state-owned oil and gas pipeline operator BOTAS are working on the realization of a joint Turkey-Bulgaria gas interconnection project (ITB), for which Bulgartransgaz has prepared a feasibility study for the Bulgarian territory co-funded by the EU under the Connecting Europe Facility (CEF) mechanism. This feasibility study was sent to the Turkish side and BOTAS' position in response is expected.

Bulgaria is paying special attention to this project, which ensures the development of reversible interconnections of gas transmission networks of Bulgartransgaz and BOTAS. The project is an opportunity to allow for the diversification of natural gas sources, the supply to both partners and routes, and greater competition while enhancing the security of supply in the region.

For realization of the project, on March 12, 2014, a Memorandum of Understanding (MoU) for the construction of the ITB was signed between the Bulgarian Ministry of Economy, Energy and Tourism and the Turkish Ministry of Energy and Natural Resources. Subsequently, the MoU was put into force on March 28, 2016, and a joint working group composed of experts from the companies involved in the implementation of the project was set up.

The 77km-long gas pipeline (75 km on Bulgarian territory and 2 km on Turkish territory) will carry up to 3 bcm of natural gas per year initially, the pipe diameter will be 28 inches (700 mm) and the working pressure 75 bar. No set date has been announced for its construction.

VI. Interconnector Bulgaria-Serbia (IBS)

Interconnector Sofia-Dimitrovgrad (Serbia)-Nis (Serbia) will connect the 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.

January 2017’s cold blast spanning the SEE region was a suitable moment for the signing ceremony of the Memorandum of Understanding for the development of bidirectional gas interconnector between Bulgaria and Serbia. In 2012, the then Serbian prime minister Dačić signed in Brussels a similar document for the same project with the Bulgarian prime minister Borisov. At the time, the signing was largely interpreted as an attempt to appease the EU and the Energy Community over Serbia's participation in the South Stream project, which was considered non-compliant with the Third Energy Package. However, notwithstanding subsequent collapse of the South Stream project, there has been no significant progress with the IBS on the Serbian side. Lack of financing support from the EU for the Serbian side of the IBS was cited as a reason for the impasse. Serbia was not willing to finance the development of its portion of the IBS, notwithstanding favourable infrastructure loans offered by EBRD. The value of the Serbian portion of IBS is around €80 million.

The latest MoU is an effort to re-energize the development of this important piece of gas infrastructure. IBS would open the Serbian gas market to gas supplies from the planned Alexandroupolis FSRU in northern Greece, as well as from TAP and TANAP. No set date has yet been announced for the pipeline construction.

VII. Interconnector Albania-Kosovo (IAK)

This 260km transmission supply project would create the preconditions for the further development of the gas markets of Albania and Kosovo in the estimated annual level of 2 bcm (1-1.3 bcm for Albania and 0.5-0.7 bcm for Kosovo). It would be possible to increase its capacity (double or triple) in the case that IAK will be used to supply Serbia and other countries with Caspian or Middle East gas, achieving thus a regional gas market integration.

The project aims to establish a new supply route for natural gas from the Middle East and Caspian Region transported by TAP, north-eastwards of the Western Balkans area towards Serbia. The project is now at feasibility study stage (€300,000 EU grant). If constructed, it will enable the gasification of Albania and Kosovo and thus provide a diversified and reliable natural gas supply to both countries, whose impact on the environment should be lower than the current fuels (firewood, coal, fuel oil).

VIII. Interconnector Serbia-Kosovo (ISK)

This interconnector will enable gas flows from TAP or Hungary to Kosovo and Montenegro. It will provide gas to non-gasified West Balkans regions (i.e. Kosovo, Albania). There is also potential of natural gas supplies from current and future storages in Serbia (Banatski Dvor, Itebej) to FYR of Macedonia.

IX. Interconnector Serbia-Croatia (ISC)

This interconnector will integrate existing and future gas storage facilities in Serbia (Banatski Dvor, Itebej) into the regional gas market. It will supply gas from Krk LNG Terminal in Croatia (when constructed) to Serbia, Bulgaria, etc.

(b) Main national gas pipelines

This chapter analyses the key national gas infrastructure projects that will be implemented in selected SEE countries, including Bulgaria, Croatia, Greece, Romania, Slovenia and Turkey.

Bulgaria

In terms of Bulgaria, nine gas projects are expected to be realized with the financial support of the country's TSO Bulgartransgaz and two as Third Party projects, as shown in Map 18 and Tables 18 and 19. Related maps and tables were extracted from the gas regional investment plan 2017-2026 of the European Network of Transmission System Operators for gas (ENTSOG) (11).

Map 18 – Location of Bulgaria's gas projects

Source: ENTSOG

Table 18 – Bulgaria's TSO gas projects

No.	Project	TYNDP Code	Status	Commissioning (TYNDP 2017)	TSO/Sponsor
1	Interconnection Turkey-Bulgaria	TRA-N-140	Non-FID, PCI 7.4.2	2020	BULGARTRANSGAZ
2	Eastring-Bulgaria	TRA-N-654	Non-FID, PCI 6.25.1	2021	
3	Rehabilitation, Modernisation and Expansion of the NTS	TRA-N-298	Non-FID, PCI, 6.8.2	2020	
• 4	A project for the construction of a gas pipeline BG-RO	TRA-N-379	Non-FID, PCI 6.8.4	2018*	
5	UGS Chiren Expansion	UGS-N-138	Non-FID, PCI 6.20.2	2022	
6	Looping CS Valchi Dol – Line valve Novi Iskar	TRA-N-592	Non-FID, PCI 6.25.4	2022	
7	Varna-Oryahovo gas pipeline	TRA-N-593	Non-FID, PCI 6.25.4	2022	
8	Construction of a Looping CS Provadia – Rupcha village	TRA-N-594	Non-FID, PCI 6.25.4	2022	
9	Construction of new gas storage facility on the territory of Bulgaria	UGS-N-141	Non-FID	Not defined	

Source: ENTSOG

Table 19 – Bulgaria's Third Party projects

No.	Project	TYNDP Code	Status	Commissioning (TYNDP 2017)	TSO/Sponsor
1	Interconnection Bulgaria – Serbia	TRA-F-137	FID, PCI 6.10	2018**	Ministry of Energy of Bulgaria
2	Interconnector Greece-Bulgaria (IGB Project)	TRA-F-378	FID, PCI 6.8.1	2018**	ICGB AD

• Project not marked on the map
* The commissioning year is now "not defined"
** Updated commissioning year 2020

Source: ENTSOG

Croatia

In terms of Croatia, twelve gas projects are expected to be realized with the financial support of the country's TSO Plinacro and one as Third Party project, as shown in Map 19 and Tables 20 and 21.

Map 19 – Location of Croatia's gas projects

Source: ENTSOG

Table 20 – Croatia's TSO gas projects

No.	Project	TYNDP Code	Status	Commissioning (TYNDP 2017)	TSO/Sponsor
1	Compressor station 1 at the Croatian gas transmission system	TRA-F-334	FID PCI 6.26.3	2017*	plinacro
2	LNG evacuation pipeline Omišalj - Zlobin (Croatia)	TRA-N-090	Advanced Non-FID PCI 6.5.1	2018*	
3	Interconnection Croatia Slovenia (Lučko-Zabok-Rogatec)	TRA-F-086	FID** PCI 6.26.1	2019	
4	Interconnection Croatia -Bosnia and Herzegovina (Slobodnica-Bosanski Brod)	TRA-N-066	Advanced Non-FID	2019	
5	LNG evacuation pipeline Zlobin-Bosiljevo-Sisak-Kozarac	TRA-N-075	Advanced Non-FID PCI 6.5.2	2020	
6	Interconnection Croatia-Bosnia and Herzegovina (South)	TRA-N-302	Advanced Non-FID	2021	
7	Ionian Adriatic Pipeline	TRA-N-068	Advanced Non-FID	2022	
8	Compressor stations 2 and 3 at the Croatian gas tranmission system	TRA-N-1057	Non-FID PCI 6.26.3	2020	
9	Interconnection Croatia/Serbia (Slobdnica-Sotin-Bačko Novo Selo)	TRA-N-070	Non-FID	2023	
10	LNG Evacuation Pipeline Kozarac-Slobodnica	TRA-N-1058	Non-FID PCI 6.5.2	2023	
11	Interconnection Croatia-Bosnia and Herzegovina (west)	TRA-N-303	Non-FID	2026	
12	Interconnection Croatia/Slovenia (Umag-Koper)	TRA-N-336	Non-FID	2026	

Source: ENTSOG

Table 21 – Croatia's Third Party project

No.	Project	TYNDP Code	Status	Commissioning (TYNDP 2017)	TSO/Sponsor
1	LNG terminal Krk	LNG-N-082	Non-FID PCI 6.5.1	2018*	lng

* Commissioning date has been updated to 2020

** This project has lost its FID status

Source: ENTSOG

Greece

In terms of Greece, twelve gas projects are expected to be realized with the financial support of the country's TSO DESFA and four as Third Party projects, as shown in Map 20 and Tables 22 and 23.

Map 20 – Location of Greece's gas projects

Source: ENTSOG

Table 22 – Greece's TSO gas projects

No.	Project	TYNDP Code	Commissioning (TYNDP 2017)	Status	TSO/Sponsor
1	Komotini – Thesprotia pipeline	TRA-N-014	2023*	Non-FID PCI 7.1.7	DESFA Hellenic Gas Transmission System Operator S.A.
2	Compressor Station at Kipi	TRA-N-128	2020	Non-FID PCI 6.9.3 PCI 7.1.2 PCI 7.4.1	
3	Greek part of Tesla project	TRA-N-631	2020	Non FID PCI 6.25.2	
• 4	M/R station at Komotini	TRA-N-940	2020	Non_FID PCI 7.1.6	
• 5	M/R station at Nea Messimvria	TRA-N-941	2019	FID PCI 7.1.6	
• 6	M/R at Komotini to IGB**	TRA-N-957	2020	Non-FID	
7	M/R at Alexandroupoli	TRA-N-1090	2020	Non-FID	
• 8	M/R at UGS South Kavala	TRA-N-1092	2023	Non-FID	
• 9	M/R at Megalopoli	TRA-N-1091	2022	Non-FID	
10	Nea-Messimvria to FYRoM pipeline	TRA-N-967	2020	Non-FID	
11	Compressor station at Nea Messimvria for connection to TAP	TRA-N-971	2022	Non-FID	
12	Revythoussa (2nd upgrade)	LNG-F-147	2018	FID	

Source: ENTSOG

Table 23 – Greece's Third Party projects

No.	Project	TYNDP Code	Commissioning (TYNDP 2017)	Status	TSO/Sponsor
1	LNG terminal in northern Greece/ Alexandroupolis – LNG Section	LNG-N-062	2018	Non-FID PCI 6.9.1	gastrade
2	LNG terminal in northern Greece/ Alexandroupolis – Pipeline Section	TRA-N-063	2018	Non-FID PCI 6.9.1	
3	South Kavala UGS	UGS-N-385	2022	Non-FID	HELLENIC REPUBLIC ASSET DEVELOPMENT FUND
4	Interconnector Greece-Bulgaria (IGB Project)	TRA-F-378	2018	FID, PCI 6.8.1	ICGB AD

• Project not marked on the map

* This project is on hold due to lack of expression of interest by the market

** This project is included in the TYNDP 2017–26 but will most probably be part of the IGB project

Source: ENTSOG

Romania

In terms of Romania, eight gas projects are expected to be realized with the financial support of the country's TSO Transgaz and four as Third Party projects, as shown in Map 21 and Tables 24 and 25.

Map 21 – Location of Romania's gas projects

Source: ENTSOG

Table 24 – Romania's TSO gas projects

No.	Project	TYNDP Code	Status	Commissioning (TYNDP 2017)	TSO/Sponsor
1	Romania-Bulgaria Interconnection (EEPR-2009-INTg-RO-BG)	TRA-F-029	FID	December 2016	TRANSGAZ MAGISTRALA ENERGIEI
2	NTS developments in North-East Romania	TRA-N-357	Advanced Non-FID	2018	
3	Interconnection of the NTS with the DTS and reverse flow at Isaccea	TRA-N-139	Non-FID PCI – 6.15	2019	
4	New NTS developments for taking over gas from the Black Sea shore	TRA-N-964	Non-FID	2019	
5	Development on the Romanian territory of the NTS (BG–RO-HU-AT Corridor)	TRA-N-358	Stage I – FID PCI – 6.24.2	2020	
			Stage II –Advanced Non-FID PCI – 6.24.7	2020	
6	Development on the Romanian territory of the Southern Transmission Corridor	TRA-N-362	Advanced Non-FID PCI – 6.24.8	2020	
7	Eastring – Romania	TRA-N-655	Non-FID PCI – 6.25.1	2021	
8	Further enlargement of the BG-RO-HU-AT transmission corridor (BRUA) phase 3	TRA-N-959	Non-FID PCI – 6.25.3	2023	

Source: ENTSOG

Table 25 – Romania's Third Party projects

No.	Project	TYNDP Code	Status	Commissioning (TYNDP 2017)	TSO/Sponsor
1	Sarmasel Underground gas storage in Romania	UGS-N-371	Non-FID PCI 6.20.6	2022	ROMGAZ Societatea Națională de Gaze Naturale ROMGAZ S.A.
2	New underground gas storage in Romania	UGS-N-366	Non-FID PCI 6.20.5	2023	
• 3	Depomures	UGS-N-233	Advanced Non-FID PCI – 6.20.4	2019	ENGIE Engie Romania SA
• 4	Azerbaijan, Georgia, Romania Interconnector – AGRI	TRA-N-376	Non-FID	2026	AGRI LNG Project Company SRL (RO)

• Project not marked on the map

Source: ENTSOG

Slovenia

In terms of Slovenia, fourteen gas projects are expected to be realized with the financial support of the country's TSO Plinovodi, as shown in Map 22 and Table 26.

Map 22 – Location of Slovenia's gas projects

Source: ENTSOG

Table 26 – Slovenia's TSO gas projects

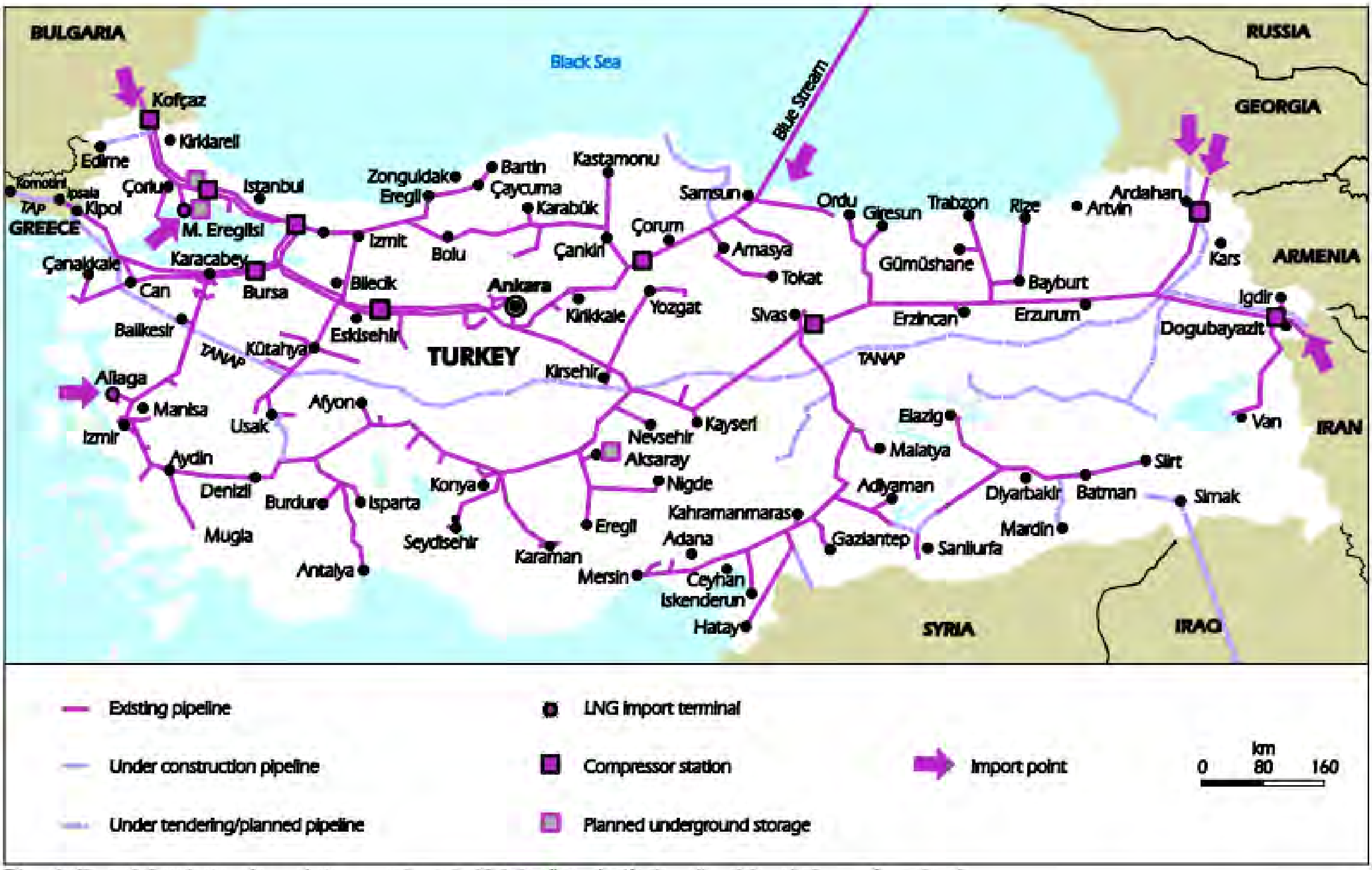
No.	Project	TYNDP Code	Status	Commissioning (TYNDP 2017)	TSO/Sponsor
1	Upgrade of Rogatec interconnection (M1A/1 Interconnection Rogatec)	TRA-N-390	Advanced Non-FID PCI 6.26.6	2020	Plinovodi Connected through energy
• 2	M6 Ajdovščina – Lucija	TRA-N-365	Non-FID	2019	
3	CS Kidričevo, 2nd phase of upgrade	TRA-N-094	Non-FID PCI 6.26.2	2020	
4	M3 pipeline reconstruction from CS Ajdovščina to Šempeter/Gorizia	TRA-N-108	Non-FID	2020	
5	R15/1 Pince – Lendava – Kidričevo	TRA-N-112	Non-FID PCI 6.23	2020	
6	Upgrade of Murfeld/Ceršak interconnection (M1/3 Interconnection Ceršak)	TRA-N-389	Non-FID PCI 6.26.5	2020	
7	CS Ajdovščina, 1st phase of upgrade	TRA-N-092	Non-FID	2021	
8	CS Ajdovščina, 2nd phase of upgrade	TRA-N-093	Non-FID	2022	
9	M3/1a Šempeter – Ajdovščina	TRA-N-099	Non-FID	2022	
10	M3/1c Kalce – Vodice	TRA-N-261	Non-FID	2022	
11	M3/1b Ajdovščina – Kalce	TRA-N-262	Non-FID	2022	
12	M8 Kalce – Jelšane	TRA-N-101	Non-FID	2022	
13	M6 Interconnection Osp	TRA-N-107	Non-FID	2022	
14	R61 Dragonja – Izola	TRA-N-114	Non-FID	2024	

Source: ENTSOG

Turkey

In terms of Turkey, Map 23 shows the existing and planned gas infrastructure projects.

Map 23 – Location of Turkey's gas projects



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: IEA

(c) LNG Terminals in SE Europe

I. Alexandroupolis FSRU

The Alexandroupolis FSRU project is developed by the private entity Gastrade S.A. and it will be stationed in the sea of Thrace, approximately 17.6km southwest of the town of Alexandroupolis in northeast Greece at an offshore distance of approximately 5.4 nautical miles from the nearest shore. Gastrade was established in 2010 with the objective to design, develop, operate and manage infrastructure for the reception, transmission and distribution of natural gas in. Gastrade is the first company operating in Greece to be granted a license for an Independent Natural Gas System. The company has currently two shareholders. Ms.

Eleni-Asimina Copelouzos (80%) and Gaslog Cyprus Investments Ltd. (20%), a 100% subsidiary of GasLog Ltd. GasLog Ltd, is a NYSE listed company, one of the largest international maritime corporations which builds, owns, manages and operates a fleet of 27 LNG carriers which has been recently expanded to enter the LNG FSRU segment.

According to Gastrade (12), the Alexandroupolis FSRU project will have a capacity of up to 170,000m^3 LNG storage and a nominal send-out capacity (base load) of 5.5 bln Nm^3/y. The FSRU will have a peak (without redundancy) gas send-out rate of up to 900,000 Nm^3/h corresponding to 8.3bln Nm^3/y.

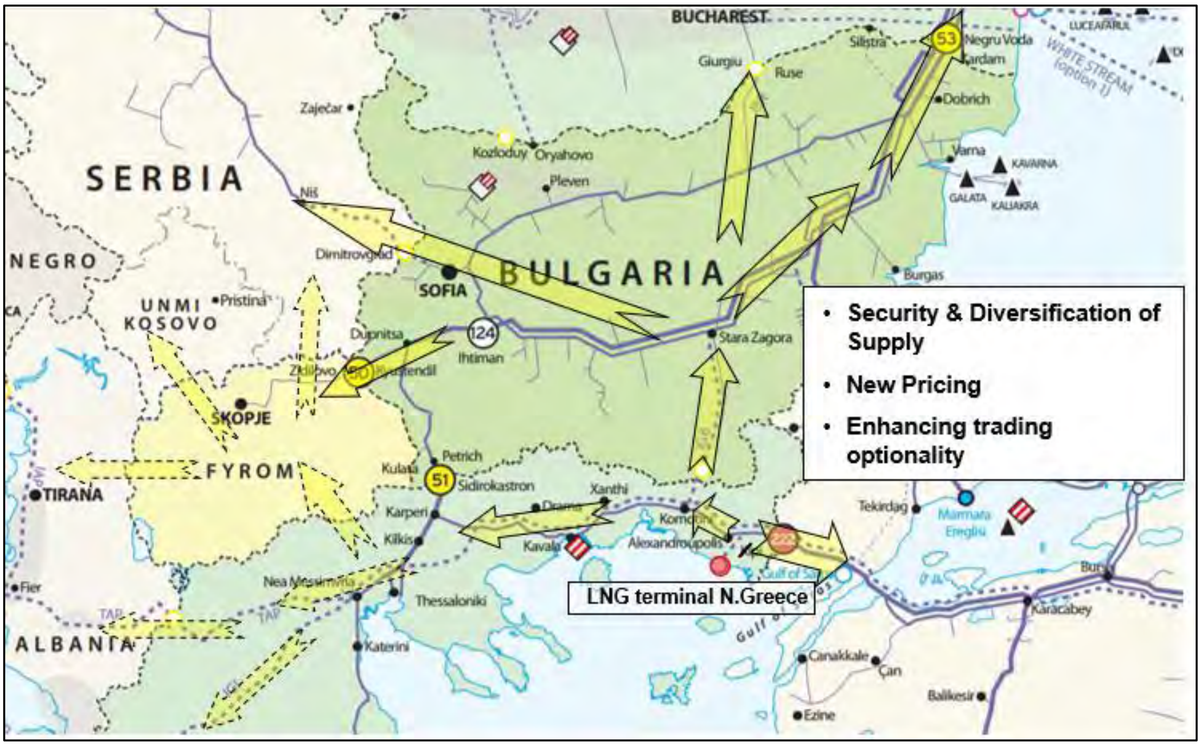
The FSRU will have 4 LNG storage tanks, associated pumps and piping and re-gasification trains with the functionality of a combined open and closed loop intermediate fluid heating medium system. The FSRU includes the LNG receiving facilities to berth incoming LNG carriers (including unloading, piping & shut down systems), boil-off gas management system, utilities & waste management systems, safety systems (hazard detection & emergency shutdown, fire protection, spill containment) and other facilities (spares & personnel transfer area) and systems (electrical, automation, control & communication).

The FSRU will have a suitable mooring and high pressure natural gas transfer system, transmitting the gas through flexible riser(s) to the pipe line end manifold (PLEM) on the seabed, where the gas transmission pipeline is connected.

The gas transmission pipeline will have a nominal diameter of up to 30". It will comprise of an approximately 24km subsea and a 4km onshore section, as shown in Maps 24 and 25. The pipeline crosses the shore approximately 4km east of Alexandroupolis. Near the shore crossing area a coastal valve station will be built.

The onshore pipeline section will terminate at the connection point with the NNGTS in the area of Amphitrite, 5.5km northeast of Alexandroupolis. At the above connection point, DESFA, the transmission system operator, will build a receiving, metering & regulating (M/R) station. The project is an EU Project of Common Interest (PCI) and it has been designed in line with the recommendations of the relevant authorities and the issued licenses' requirements.

Map 24 – Alexandroupolis FSRU terminal

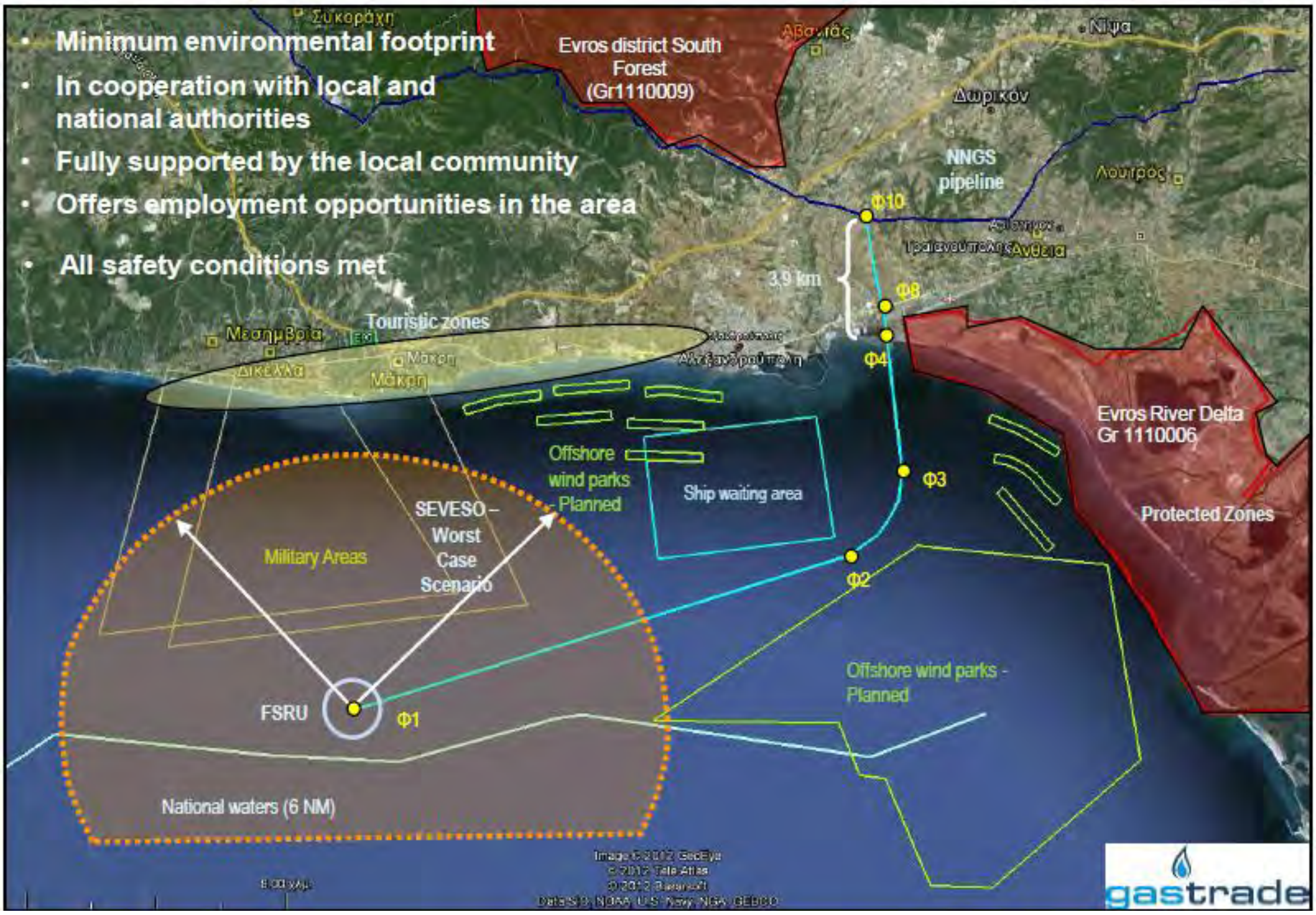


Source: Gastrade

Map 25 – Alexandroupolis FSRU terminal

Source: Gastrade

Map 26 – Careful consideration of safety, social and environmental aspects



Source: Gastrade

In addition, Gastrade has released the latest project status update and key milestones, as shown in Table 27.

Table 27 – Alexandroupolis FSRU: Project status update and Key Milestones

Description	Timeframe
Licensing	Completed
Front End Engineering Design (FEED)	Completed
DEPA and BEH join the Project	1Q2018
Final Investment Decision (FID)	1H2018
Commercial Operations Date (COD)	1H2020

Source: Gastrade

II. The Krk LNG Terminal

This LNG Project will include the building and operation of the infrastructure necessary for receiving, storing, reloading and regasification of liquefied natural gas. The scope of this project is to secure energy needs and increase security of gas supply through the provision of new gas supply route for the Central and Southeastern European countries.

For the tender for the purchase of an FSRU as well as a docking station and other infrastructure, announced by the LNG Croatia company as part of the realization of the LNG terminal project on the Croatian island of Krk, a total of 27 bids have been received, 13 for the FSRU itself and 14 for the docking station and other accompanying facilities, as announced on October 10, 2017.

On October 6, 2017, the deadline passed for submitting requests for participation in both international public tenders – the first for the delivery of a floating terminal for transfer, storage and gasification, together with the provision of management and maintenance services, and the second for the design and construction of the docking station, auxiliary facilities and the pipeline. It is expected that the tenders will result in a successful conclusion of contracts by early 2018. The initial deadline for applications for both tenders to be submitted was September 29, 2017, but it was later extended until October 6, 2017. After the prequalification phase, a call for binding offers will be announced.

According to plans, the LNG terminal on the island of Krk is supposed to be completed by the end of 2019, which was a condition for co-financing of the project from the EU funds, while the first gas deliveries from the terminal should begin a year later. The prerequisite for the money to be used it that they must be spent exclusively for the purchase of the FSRU. In this way, LNG Croatia has lost the possibility of leasing the terminal, which is the usual model for developing similar projects in the world. The advantage of leasing is that, despite larger short-term operating costs, it reduces the investment risk and enables the initial stage of the market development without the risk of so-called sunk costs.

Developers of the Croatian LNG terminal will have to either buy one of the already existing floating terminals which are no longer needed by their owners or order the construction of a new terminal according to specifications. However, since global shipyards are full and the building of a terminal lasts for about two years, it would appear that – even if the construction were to begin today – the initial goal of the terminal being operational in 2019 could no longer be met.

All in all, a lot of serious questions still lie ahead of those responsible for the realization of the LNG project on Krk.

Map 27 – Krk LNG Terminal

Source: Interfax

(d) Gas Storage Facilities in SE Europe

The use of underground gas storage capacities is an efficient way of securing uninterrupted, reliable, and flexible gas supplies. Currently, in SE Europe, there are 13 underground gas storage facilities in operation in 5 countries, which are Romania, Croatia, Serbia, Bulgaria and Turkey and all of these facilities are mostly based on depleted gas fields.

Romania has eight underground gas storage facilities, four of which are located in the center of the country, while the others are located near Bucharest, in the south. Romania is second among the region's countries in terms of working gas capacity, having the ability to store up to 3.1 bcm of gas in its underground facilities.

Croatia has one underground facility for gas storage, which is located in the south of the capital Zagreb. The working gas capacity of Okoli UGS amounts to 553 mcm of gas. In periods of high demand, the gas is withdrawn at a daily rate of up to 5.8 mcm, while the injection rate approaches 4 mcm/d.

Serbia uses one depleted field as underground facility for gas storage, which is located at the country's north, in the village Banatski Dvor, near the border with Romania. The total working gas capacity is 450 million cubic meters of gas.

Bulgaria has one underground gas storage facility, which is also a depleted gas field. It is located in Chiren, to the north of the capital Sofia. The total capacity of the Bulgarian underground facility amounts to 550 mcm of gas. Bulgartransgaz, the combined operator performing licensed activities of natural gas transmission and storage, is the facility's operator, having received a license from the Bulgarian regulator (SEWRC) in 2006.

Turkey has two gas storage facilities, close to Istanbul, with a combined storage capacity of 2.84 bcm in two depleted gas fields (Kuzey Marmara and Değirmenköy).

The countries in SE Europe are expected to be active in the coming years, developing some new underground gas storage facilities. The need for additional regional gas storage capacity becomes even more evident, especially if we consider the forecast that Europe will increase its dependence on imported gas to 70% by 2030. The gas consumption in Europe, up to 2030, is estimated to reach 640 bcm, while imports and storage capacity are estimated to rise to 490 and 140 bcm respectively.

Bulgaria and **Croatia** have announced their intention to upgrade their storage facilities. As mentioned earlier, in **Bulgaria**, there is a current gas storage capacity of 500 mcm in an underground site in Chiren. The target is the facility's upgrade so as the new capacity to reach 1 bcm and the withdrawal rate to be 10 mcm/d. After this development, Bulgaria would be able to cover all its domestic needs and those of neighbouring countries. The **Croatian** state company Podzemno Skladiste Plina (PSP), having already completed the preparatory actions, will proceed with the construction of a much needed new gas storage facility, which is expected to ameliorate the fluctuations of domestic gas consumption. The new facility will be located in the east of the country and specifically in the area Grubisno Polje with a gas storage capacity of 25-40 mcm. There are also plans for another UGS in Beničanci, a village in northeast Croatia, with a planned annual gas storage capacity of 2 bcm.

Albania has several suitable sites for gas storage, including, a salt dome in Dumrea (up to 2 bcm) and the depleted Divjaka gas field (up to 1 bcm). Based on a preliminary feasibility study, the possible UGS at Dumrea Salt Dome could have the cheapest cost for gas storage, about $76/mcm.

In **Romania**, Romgaz, the largest natural gas producer and the main supplier, announced in September 2014 that it has completed an investment of €27 million to upgrade the UGS facility in Urziceni, from 250 mcm to 350 mcm, thereby increasing the company's overall gas storage capacity to 2.8 bcm.

Turkey is expected to follow a similar path, going ahead in developing new underground gas storage facilities. In July 2014, Turkey signed a loan agreement of 400 million dollars with the World Bank for the construction of a new underground gas storage facility in the lake Tuz Golu, which is located in central Anatolia. The project, which was opened in February 2017, was developed by the state company Botas while the storage capacity of the facility amounts to 960 mcm, with a daily withdrawal rate up to 40 mcm. According to Gas Storage Europe (GSE), Turkish Petroleum Corporation (TPAO), which developed and manages the existing underground facility at Kuzey Marmara, is expected to proceed with expansion works, which will add to the overall gas storage capacity an additional 1.66 bcm of gas.

In **Serbia**, the expansion of the existing underground gas storage in Banatski Dvor is being examined, so as the new capacity to be upgraded from 450 mcm to 1.2 bcm. The only possible underground gas storage project in **Greece** is the depleted gas field in South Kavala, but as several analysts point out, this project is expected to proceed only through public-private partnership.

The total underground gas storage capacity in SE Europe, which is estimated at 13.64 bcm in 2015, is just enough to cover periodic peaks but is not regarded as adequate for planning purposes and for ensuring long-term security in the various countries' energy systems. In this respect, LNG has lately been identified as a suitable alternative which can successfully augment grid demands during prolonged peak demand periods. Currently, only Greece and Turkey in SE Europe use LNG to complement the operation of their national gas systems while a number of new projects are in the offing, including Krk LNG terminal in Croatia. Table 28 summarizes the planned new underground gas storage projects in SE Europe.

Table 28 – Planned New Underground Gas Storage Facilities in SE Europe

Country	Location	Capacity (bcm)	Predicted start date
Bulgaria	Chiren	0.5 (upgrade)	2018/2019
Croatia	Grubisno Polje	0.04	2019
Romania	Urziceni	0.1 (upgrade)	2015
Serbia	Itebej/Banatski Dvor	1/0.75 (upgrade)	NA
Greece	South Kavala	0.36	NA
Turkey	Tuz Golu	1	2018/2019
	Kuzey Marmara	1.66 (upgrade)	NA

NA – There is no reliable information on the scheduled starting date

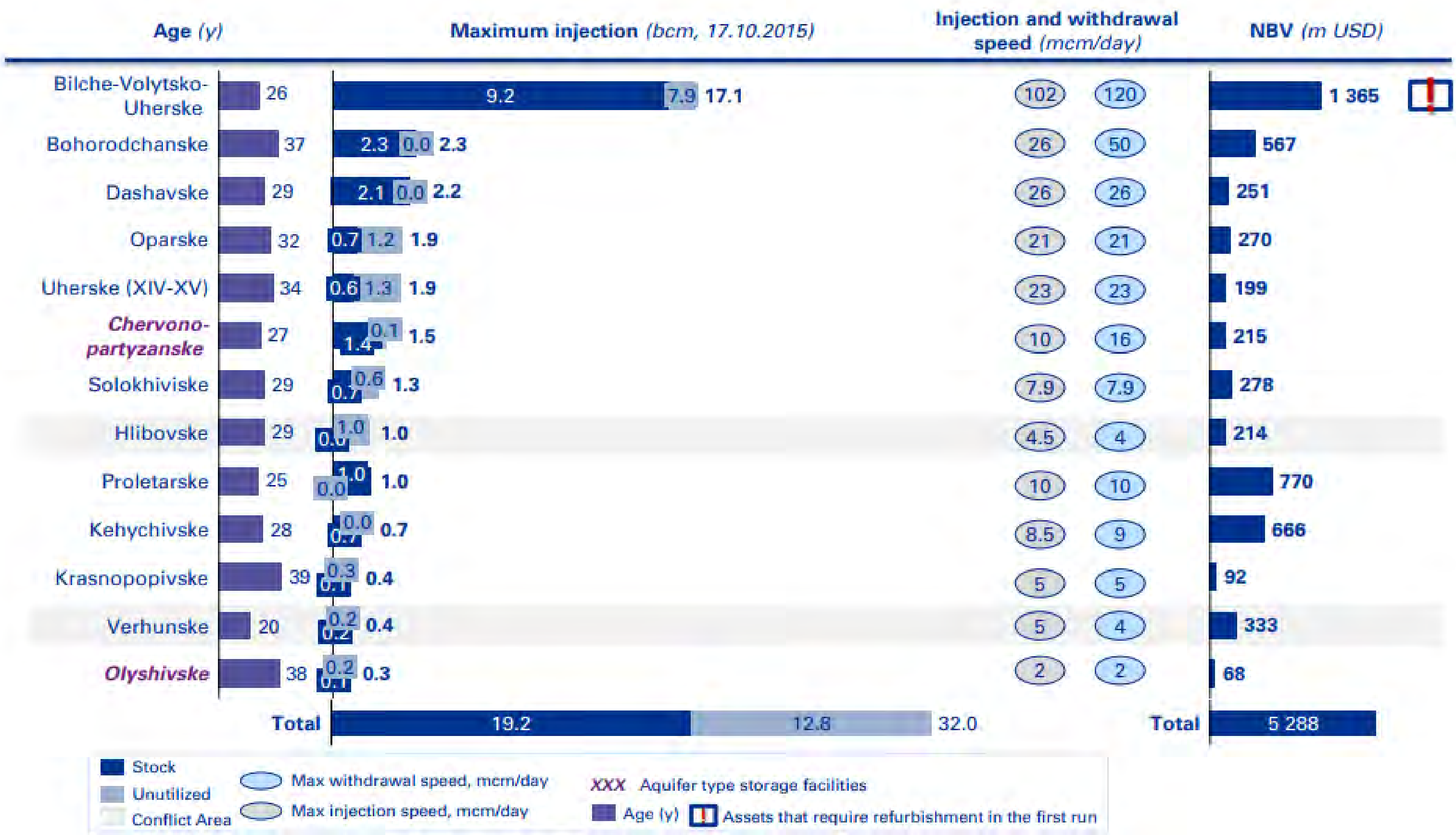
Source: IENE

Ukraine

Ukraine has an extensive natural gas transit and transmission system and owns one of the largest natural gas underground storage facilities in Europe. There are 13 underground natural gas storage facilities (GSFs) which can be identified based on three geographical areas:

1. ***East:*** There are 7 GSFs with a total 6.1 bcm maximum available capacity. These mainly satisfy local internal consumption needs.
2. ***West:*** There are 5 GSFs with a total 25.3 bcm maximum capacity, mainly used for swaps with gas taken from transit volumes in the east in winter to serve the demand for transit to the EU (not used directly for transit purposes).
3. ***South:*** There was only one storage facility (Hlibovske) which is located in the Crimea with a total capacity of 1 bcm. Since 2014 this storage facility has not been operated by the Ukrainian TSO anymore.

Figure 28 – Technical characteristics of Ukraine's gas storage facilities



Sources: Ukrtransgaz

Only one of the storage facilities (Hlibovske) was operated by Chornomornaftogaz (subsidiary of Naftogaz). The other twelve storages are operated by UTG. The majority of underground storage facilities were built within depleted gas fields, while two of them were built on the foundations of waterbearing structures (aquifers).

The Ukrainian underground gas storage system has one of the largest available capacities in Europe – 32.4 bcm. The largest storage facilities are located in the western part of Ukraine, their capacity is mainly used for swaps with gas taken from transit volumes in the east in winter, in order to satisfy the demand for transit to the EU (they are not used directly for transit purposes) and they are connected to the main transit transmission lines (Soyuz, Progress and UPU). Their combined capacity is 25.3 bcm, making up 79.2% of Ukraine's total Underground Gas Storage (UGS) capacity. The eastern storages have a combined capacity of 6.1 bcm (17.6% of Ukraine's total UGS capacity) and the southern storage has 1 bcm (3.1% of Ukraine's total UGS capacity).

With an average age of 32 years, the western storage facilities are the oldest ones, while the eastern and the southern storages have an average age of 29 years. This is considered old compared to the average age of the EU storage facilities, which is approximately 17 years.

On the maximum injection day (17 October 2015) the highest rate of utilisation was only 51%, which is moderate compared to the EU average (65%)[26]. Nevertheless, it was sufficient to satisfy transit needs.

Due to their age and physical condition (porous), the storage facilities are inflexible in terms of injection and withdrawal. So, injection mostly takes place in the summer, while withdrawal is typically in winter. Generally, there are technical and time limitations to switch instantly from injection to withdrawal and vice versa.

In late 2014, Chornomornaftogaz lost its access to the Hlibovske storage facility located in the Crimea and UTG lost its Verhunske storage facility located in the conflict zone in eastern Ukraine. However, these events had a negligible impact on transit activities as these storage facilities mainly served domestic demand. As a result, the storage utilisation in these facilities is essentially zero.

6. LNG supply overview in SE Europe

Although LNG imports in Europe during 2015 continued to decline, registering almost minus 2 bcm compared to 2013, the prospects for a reversal of this downward trend over the next five years look better than ever before.

In its 2015 Mid-Term Gas Report, IEA says that Europe together with China and non-OECD Asia will see a sharp LNG import increase in view of growing demand and market restructuring. Apparently, Europe will emerge as a residual market, importing what other regions do not take. To this end, Europe's current huge excess of LNG import capacity is a major contributing factor. The excess capacity today is unevenly distributed between Western and SE Europe and Central Europe. Consequently, EU's much touted 'brave new' LNG strategy, when finalized, will have to take into consideration the need to strengthen SE Europe's LNG regasification capacity. Although plans for adding new capacity in certain countries of the region are at an advanced stage (see Croatia's Krk terminal and Greece's FSRU in Alexandroupolis), there is still some way to go before FID's are taken.

[26] According to the GIE database, utilisation of the EU storage facilities in 2016 was around 65% throughout the whole year.

Regardless of present delays, there appears to be firm commitment from Brussels, as indicated in the inclusion of such projects in the PCI programme. In this respect, it is expected that the SE European region will play a significant role in expanding LNG trade in Europe by 2020 through the construction and operation of the above two new LNG regasification projects and possibly of others that will follow (e.g. Cyprus, Turkey, Albania).

In 2014, SE Europe was responsible for approximately 8 bcm of LNG imports, or 15.5% of total European OECD gas imports. This is not an insignificant quantity, given that the two countries which contributed these volumes, Greece and Turkey, are not part of the main (interconnected) European gas markets and have both experienced a slowdown in gas demand. Of course, Turkey's role, given its size and the volume of its gas market is far more important having imported 7.3 bcm of LNG compared to Greece 0.8 bcm. We should recall that Turkey's gas consumption for 2014 reached 48.6 bcm (up to 6.5% compared to 2013) while in Greece there was a slump to 2.7 bcm, 23.5% compared to previous year largely attributed to the persisting economic depression and electricity market distortions.

We should further note that Greece and Turkey are the only countries, out of the 18 countries in the broader Black Sea-SE European region which at present possess LNG regasification terminals which are well linked and integrated to their national gas systems. These terminals and their characteristics are shown in Table 29.

Table 29 – LNG Regasification Terminals in SE Europe

Country	Terminal	Start	Storage	Regasification capacity/year	Owners	Concept
Greece	Revithoussa	2000	130,000 m^3 LNG	5.0 billion m^3	DESFA (100%)	Onshore
Turkey	Aliaga LNG	2006	280,000 m^3 LNG	6.0 billion m^3	Egegaz (100%)	Onshore
	Marmara Ereglisi	1994	255,000 m^3 LNG	8.1 billion m^3	Botas (100%)	Onshore
	ETKI LNG	2017	145,000 m^3 LNG	7.1 billion m^3	Etki Liman Isletmeleri Dolgalgaz Ithalat ve Ticaret (100%)	FSRU

Source: IENE

Following the launch of Turkey's first FSRU terminal in Aliaga (i.e. ETKI LNG terminal), north of the port city of Izmir on the country's Aegean coast in December 2016, Turkey is planning further FSRU projects, as the country is aware of the importance of LNG to enhance its security of supply. The planned new FSRU projects will be docked near the Port of Saros in

Eastern Thrace and in Dörtyol, a district in the southern province of Hatay, in southern Turkey, providing gas to the national system.

Table 30 – Planned LNG Gasification Terminals in SE Europe

Country	Location	Storage capacity (cm)	Annual capacity (bcm)	Technology
Croatia	Krk island	2x180,000	4-6	FSRU
Greece	Alexandroupolis	170,000	5.5-8.3	FSRU
Turkey	Gulf of Saros	70,000	5-6	FSRU
	Dörtyol/Hatay	263,000	10	FSRU
	Aliaga	280,000	6.3	Land based

Source: IENE

In Greece, the FID decision for the FSRU project in Alexandroupolis is expected to be taken during the first half of 2018. That brings the total number of LNG projects in the area up to five, with all of them being at an advanced planning stage with the Krk and Alexandroupolis already included as PCI's by the EC. Even if three of these projects actually get built, the region's LNG capacity will have expanded immensely, helping change market dynamics in the Adriatic-Aegean axis. Such development will undoubtedly enhance regional gas trade and refocus Mediterranean gas trade movements. These trends will be greatly influenced by the emergence of LNG bunkering as a potentially promising activity in the area.

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

7. The strategic role of LNG in securing future gas supply in SE Europe

LNG, along with underground gas storage, provides certain flexibility in gas supply which could prove immensely useful in times of crises as it was shown in the case of Greece, Bulgaria and Turkey in February 2011 and also recently in December 2016-February 2017. Flexibility supply from LNG and underground gas storage is to a certain extent not interchangeable due to different operational characteristics and geographical location.

LNG regasification facilities provide a high regasification capacity; globally this amounts to up to 1,080 bcm of gas in the gaseous state, according to the IEA[27]. A high concentration of regasification capacity is found in Japan (286 bcm) and Korea (161 bcm). In Europe, there is

[27] IEA (2017a), "Gas Market Report 2017 – Analysis and Forecasts to 2022"

211 bcm regasification capacity installed, mainly located in South and North-West Europe. For the winter period, this equals a potential LNG supply of 105 bcm in Europe, about the same as underground storage. LNG in Europe can provide about 0.55 bcm/day of peak regasification capacity. In the case of SEE, only Greece and Turkey have LNG regasification facilities. Among them, there is a current total regasification capacity peak of 21.2 bcma.

Today, Floating Storage Regasification Units (FSRU) are widely recognized as a vital component required while transiting and transferring LNG through the oceanic channels. Thus, FSRU can be termed as a special type of ship or vessel and as an offshore unit, terminal or installation, which is used for LNG transfer. However, viable and exceedingly environment-friendly LNG is the fact remains that transporting it is not as easy.

FSRU can also be seen as a "fast track" way of opening energy markets to natural gas. It provides much reduced construction time, costs are much less than land based alternatives of a similar size and it generally faces less local opposition than new onshore terminals. FSRUs have also great flexibility with respect to location and use as they can be reused at new locations at a later stage.

In 2016, Europe's net LNG imports totalled 51 bcm, which represented 15.3% of the global LNG market (17). Although LNG imports to Europe slowed down in the second half of 2016, Europe is still considered to be a significant market for LNG. In 2015, eleven countries in Europe imported LNG. Currently, Europe has 29 LNG import terminals in operation, with a total LNG regasification capacity of 208 bcm (18). The LNG import terminals are mainly large scale, but FSRUs and small-scale terminals are playing an increasingly important role in LNG regasification (see Table 31).

Table 31 – LNG import terminals per type in Europe

Type	Operational	Under construction	Planned
Large scale	24	3	23
FSRUs and others	2	0	11
Small scale	4	4	4
Total	**29**	**6**	**27**

Note: Figures may not add up due to overlap in categories.

Source: Gas Infrastructure Europe (2017)

As can be seen from the above, Europe currently has an oversupply of regasification capacity and theoretically the region could receive approximately 160 bcm of additional LNG with the existing infrastructure. However, there is a regional mismatch: regasification capacity is concentrated in Western Europe, along the Mediterranean and Atlantic coasts while there is limited access to LNG in Central and Southeast Europe due to the lack of LNG regasification capacity and interconnectors. Weak interconnections between EU countries are a major obstacle preventing LNG from flowing across the EU. Notwithstanding the underutilization rate, 33 additional terminals are either currently under construction or planned (see Table 31). The construction of terminals in Central and Eastern European countries could reduce dependency of these countries on Russian gas supplies and improve price competition. LNG terminals are also being expanded, constructed or reopened in Europe in anticipation of the growing role LNG will play in European energy supply.

In SE Europe, LNG seems to be the only realistic alternative fuel as it increases security of supply through multiple and independent supply sources, provides the opportunity for new LNG suppliers (e.g. Australia, US, etc.) to export gas to the region, enhances pricing flexibility and safer gas transportation and can support underperforming gas pipeline projects, among others.

The Alexandroupolis FSRU project as part of an expanded South Corridor

The selection of Alexandroupolis is not random but takes into consideration the increased gas liquidity in Northern Greece with the existing 296-km Interconnector Turkey-Greece, which has been in operation since 2007, the under construction TAP as well as the planned Interconnector Greece-Bulgaria, the Interconnector Greece-Italy and the potential underground gas storage in South Kavala (see Map 28). In view of the above synergies, the project can early be termed as a new gas gateway to Europe.

Map 28 – A new energy gateway to Europe

Source: Gastrade

The so-called South Corridor, through which gas from the supposedly rich in gas deposits of the Caspian region, would be channeled to energy demanding European markets, will play a pivotal role as an alternative entry gate for gas which will help Europe diversify both its energy supplies and its energy routes. In spite of its limited gas volume transit capacity (20 bcm by 2025), there is no doubt that the South Corridor could strengthen the security of Europe's energy supply by means of differentiating both supply sources and routes.

The TANAP-TAP gas pipeline system, which is now under construction, is the foundation of the South Corridor. A number of alternative plans for channeling this gas to Turkey are under discussion, either for local consumption, but also for shipment to Europe's main gas markets. These plans include gas pipelines, LNG and FSRU terminals to be tied up into the TANAP-TAP system, including the Alexandroupolis FSRU project.

An Expanded South Corridor

Another option, apart from the TANAP-TAP system, is the East Med Pipeline which again, due to the significant technical challenges, could also accommodate limited quantities of gas in the region of 8 to 12 bcm per year. Meanwhile, the European Commission is actively exploring the possibility of massively increasing the member countries' LNG capabilities as part of Energy Union priorities. The now defunct South Stream and its successor, the Turkish Stream, should also be considered as an additional vital gas supply route.

In view of several new projects under development in the SE European region, it is appropriate to redefine the South Corridor by including these planned and new potential gas supply sources and routes. Therefore, an expanded South Corridor (see Map 29) should be considered and defined as such, to include all major gas trunk pipelines and terminals which will feed gas into the system which will then be directed towards the main European markets.

Equally important to realise is that the expanded South Corridor with its multiple gas entry points and linked underground gas storage and LNG facilities will provide the necessary background for the operation of regional gas trading hubs as described in Chapter 9. In this context, the Alexandroupolis FSRU project is acquiring a new significance as it forms an important component of the expanded South Corridor concept.

"The Alexandroupolis FSRU project was described as one of pivotal importance for Europe's energy security and US interests", Robin Dunnigan, Deputy Assistant Secretary for Energy Diplomacy at the US Department of State's Bureau of Energy Resources, noted recently following talks with officials at Gastrade as well as Greece's energy minister Giorgos Stathakis. The official pointed out that the US's transformation from gas importer to exporter has led to a revision of the country's outlook on the southeast European region and projects such as the prospective Alexandroupolis FSRU. Dunnigan pointed out that annual US LNG exports are expected to exceed 100 bcm over the next five to seven years, increasing the country's global market share in the sector to around 20%. This prospect has increased the importance of the Alexandroupolis FSRU for US gas trading companies as the facility is being regarded as a gateway for American shale gas into the Balkans and central Europe.

Map 29 – An Expanded Southern Gas Corridor

NB.: The TANAP and TAP gas pipelines as well as Turkish Stream are under construction, with IGB at an advanced planning stage with FID already taken. The IAP, the IGI Poseidon in connection with East Med pipeline and the Vertical Corridor are still in the study phase.

Source: IENE's "SE Europe Energy Outlook 2016/2017" Study, Athens, Greece

Taking also into account that the Alexandroupolis FSRU project will be close to targeting markets with rising gas demand such as Bulgaria, Romania, FYROM, Hungary and Serbia that could receive gas volumes through Vertical Corridor and the fact that no other similar gas interchange exists in SE Europe, it is evident that the city can emerge as a significant regional gas hub. In addition, from January 1, 2020, Greece will need to increase its imported gas volumes from Turkey through Interconnector Greece-Turkey, which has an adequate capacity of 5 bcm, as Russia's Gazprom will stop gas supplies via the Trans Balkan pipeline which delivers Russian gas from Ukraine to Turkey passing through Moldavia, Romania, Bulgaria and Greece (19). Although Trans Balkan could theoretically be converted to reverse flow, it is nevertheless an old pipeline with technical difficulties that need to be overcome and new regulatory regime that is necessary to follow. That said, this kind of solution seems unlikely. In addition, a political issue that may arise is that the European Commission will not allow Russian gas flows to run through this route as in such case the efforts to reduce Russian gas imports will not been met. Thus, the Alexandroupolis FSRU project can emerge as an alternative gas supply option for Greece and SE Europe in general.

The key end-user destination countries expected to be served by the Alexandroupolis FSRU project are Greece, Bulgaria, Serbia, FYROM, Turkey, Romania, Hungary and Ukraine. In **Greece**, the FSRU project will feed gas volumes directly to the Greek NNGTS and the Greek market, while it could potentially feed gas volumes also into TAP. The project will serve **Bulgaria** mainly through the new interconnector Greece-Bulgaria (IGB), with capacity of 3 bcm/year (expandable to 5 bcm/year), connecting the Greek and the Bulgarian gas networks at Komotini and Stara Zagora which is under development, with the currently anticipated start of commercial operation in 2020.

Serbia is currently supplied solely through Hungary. A new interconnection (IBS) between the Serbian and Bulgarian systems, with capacity of 1.8 bcm/year is planned, expected to be commissioned in 2020. Also, **FYROM** is currently supplied through an interconnection with Bulgaria (capacity 0.6 bcm/year). As already mentioned, DESFA and FYR of Macedonian Energy Resources (FYR of MER) have signed an MoU (2016) for the construction of a 160 km gas interconnection pipeline between Greece and FYROM. Also, a separate application by independent company Windows SA for the construction of an interconnector between Greece and FYROM has been lodged with the respective regulatory authorities of both countries. In addition, FYR of MER is enhancing the domestic transmission system (construction of a gas ring), which will provide access to gas to additional consumers. Therefore, and by means of these interconnections, the Alexandroupolis FSRU project could become an alternative gas supply source to both Serbia and FYROM. For FYROM, this is absolutely necessary as the country is fast expanding its gas-powered electricity capacity.

Turkey’s existing interconnection with the Greek system (ITG) allows only single-directional flows from Turkey to Greece. Discussions between the relevant TSOs for the introduction of bi-directional functionality are on-going. Bi-directional functionality will also be introduced upon TAP’s commissioning. Thus, the Alexandroupolis FSRU could well emerge as an additional gas supply to the ever-demanding Turkish gas market. Further north, a new interconnection, with capacity of 1.5 bcm/year from Bulgaria to **Romania** (IBR) was commissioned in 2016. The current interconnection from **Hungary** to Romania has only limited reverse flow capacity (0.087 bcm/year), which will need to be enhanced for the Alexandroupolis FSRU project to be able to serve the Hungarian market. The planned upgrade of the Romania-Hungary-Austria corridor (BRUA project), expected to be fully commissioned in 2023, will allow the transfer of 4.4 bcm/year from Romania towards Hungary.

The above projects are to be connected through the Vertical Corridor which is in the process of detailed study. This new corridor, which follows a ministerial agreement between Greece, Bulgaria and Romania (November 2014), later followed by Hungary, makes use of existing infrastructure to allow gas to be pumped in a bi-dimensional way South to North and North to South[28]. Hence, the combination of the Vertical Corridor and the BRUA project will enhance gas movement across the region. With the Alexandroupolis FSRU's strategic location in the southernmost part of the Vertical Corridor, regional gas supply will be enhanced further. Finally, **Ukraine** could benefit from the Alexandroupolis FSRU terminal either through the Vertical Corridor or via a reverse-flow use of the Trans Balkan pipeline.

It is worth mentioning that Alexandroupolis FSRU will be the only new gas infrastructure project in SE Europe which will not rely on Turkey as a transit country (TANAP/TAP system, Turkish Stream, new quantities from Iran, Caspian, etc.).

8. Geopolitics and energy security in SE Europe

There can be little doubt that SE Europe's economic development and prosperity depends on a stable and abundant supply of energy. For most citizens, energy is available "on tap", it is ubiquitous and un-intrusive. This has a major influence on the factors that affect national decisions on energy policy, with security of supply not being on par with other considerations. It is true that over recent years, the economies of EU member states and of the rest of the countries in the SE European region have been exposed at times to steep energy price increases leading to adverse effects on consumers and industry. Some countries have also been confronted with disruptions to gas supply, affecting gas-dependent industrial activities and households. Arguably, the region's economy will continue to be exposed to risks related to energy price instability and energy flow variability, including potential oil shocks or oil and gas shortages.

Security of energy supply has never been an easy task, given the often unstable and unpredictable state of affairs at global level which affect both energy prices and the flow of energy itself, whether this is oil, gas or even electricity. It is worth recalling that in the winters of 2006 and 2009, temporary disruptions of gas supplies hit strongly EU citizens in some of the Eastern and SE European Member States (see also Box 1).

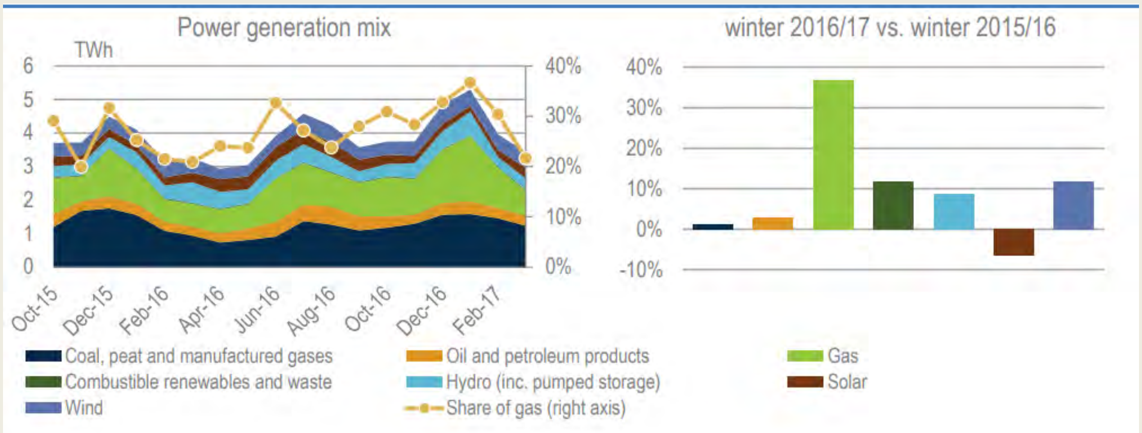
[28] IENE (2015), "The "Vertical Corridor": From the Aegean to the Baltic", M26, http://www.iene.eu/articlefiles/the%20vertical%20corridor%20-%20from%20the%20aegean%20to%20the%20baltic.pdf

This was a stark "wake up call" pointing to the need for a common European energy policy. Since then, a lot has been done in order to strengthen the EU's energy security and by extension that of SE Europe’s, in terms of gas supply availability at times crises, especially for Member States that are dependent on one single supplier, the easing of cross border gas flows, and the availability of additional storage. Yet, despite all the achievements in strengthening its infrastructure and diversifying its suppliers, the EU and SE Europe in particular, remain vulnerable to external energy shocks.

Box 1: The case study of Greece’s gas crisis

The sharp cold spell faced by southern European countries last winter led to a significant increase in Greece’s natural gas and power demand. In the case of power generation, the rise in demand (up by 12% compared with the same period the previous year) was mainly covered by gas-fired generation surging by 37% (2.1 TWh) compared with winter 2015/16, accounting for 31% of overall power generation during the winter (see Figure 1), according to IEA’s Global Gas Security Review 2017 report (13).

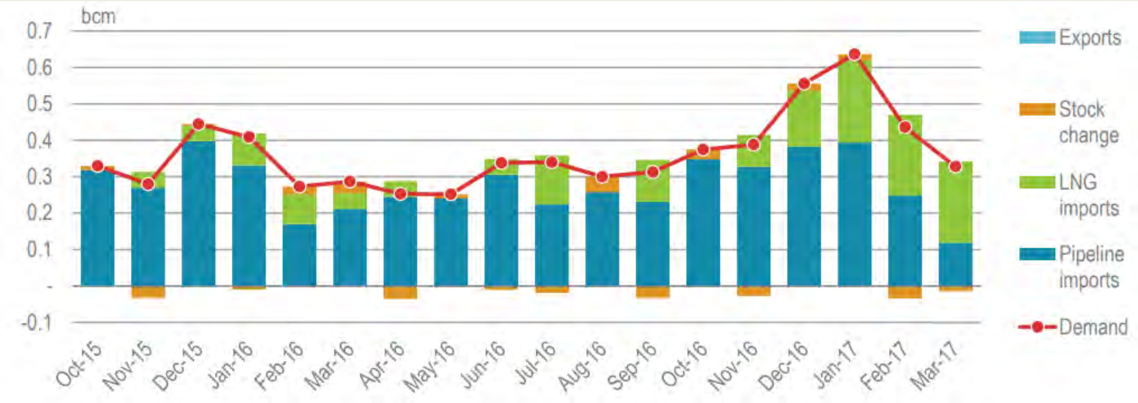
Figure 1 - Power generation mix in Greece



Source: IEA (2017b)

On top of its major role in power generation, conventional natural gas demand also rose by 32% (or 1.1 bcm) throughout the season compared with the previous winter. Due to exceptionally high demand for both domestic supply and gas-fired power generation, total natural gas demand hit an all-time monthly record of 637 mcm in January 2017 (see Figure 2), some 40% above the previous high.

Figure 2 - Natural gas supply and demand balance in Greece



Source: IEA (2017b)

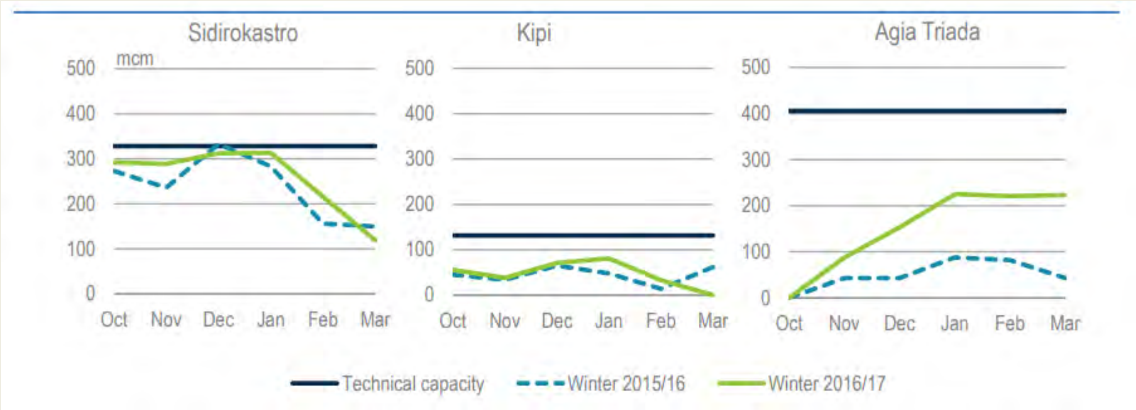
Greece has virtually no storage capacity. Therefore, the increase in gas demand had to be met by increased LNG and pipeline imports. Accordingly, LNG imports soared by 156% y-o-y to meet January demand while pipeline imports rose 19% y-o-y, accounting for 225 mcm and 394 mcm respectively.

The unpredicted increase in gas demand triggered the declaration of two consecutive alert levels to safeguard national gas and power supply. The first crisis started on December 19, 2016, with the declaration of an early warning state and lasted 13 days until business as usual resumed on December 31, 2016. The early warning was declared after a sustained increase in gas demand for seven days in a row. The delay of an Algerian LNG cargo due to bad weather conditions in late December tightened the situation, leading to the alert declaration on December 21, 2016. The second crisis started on January 9, 2017, and finished on February 13, 2017, 36 days later. In this case, the tight situation was also due to exceptionally high demand (see Figure 2). During Greece's gas crisis, the market was not able to rebalance itself and the government needed to implement several measures according to the provisions of the Greek Emergency Plan.

Handling the gas crisis

As noted above, the only viable alternative to meet the rise in gas demand was to increase pipeline and LNG imports.

Figure 3 - Greek natural gas monthly imports by entry point, winter 2016/17



Source: IEA (2017b)

Greece's natural gas system has three entry points with an annual import capacity of 10.5 bcm:

(a) Sidirokastro, which has 4.0 bcm of import capacity and serves as the entry point for Russian pipeline volumes via Bulgaria.

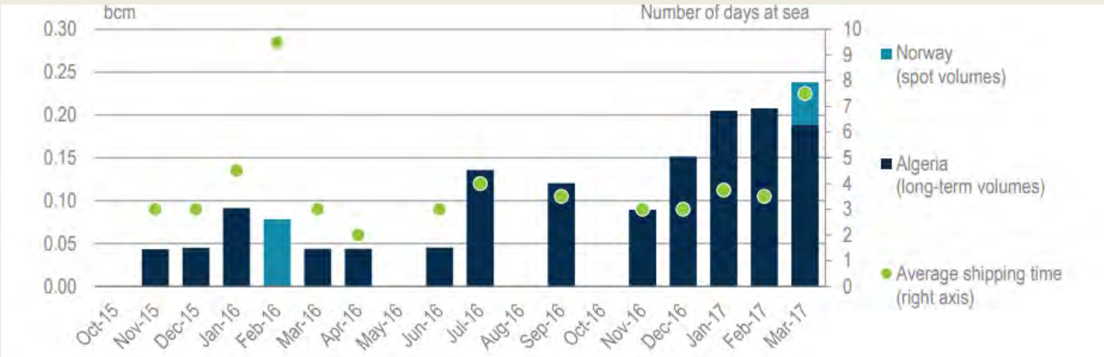
(b) Kipi, which brings Turkish pipeline gas into the country with a maximum import capacity of 1.6 bcm.

(c) Agia Triada, which offers an additional 4.9 bcm of import capacity and enables the entry into the system of LNG volumes imported at Revithoussa LNG terminal. Historically, these volumes have been long-term contracted to Algeria.

Given that pipeline imports from Bulgarian and Turkish border entry points could not be significantly increased in absolute terms, the last option left was to increase LNG imports through Agia Triada (see Figure 3). Consequently, LNG imports tripled compared to the previous winter. In order to achieve this significant increase, the country benefited from its long-term contract with Algeria. In addition, one extra spot cargo was delivered from Norway's Snohvit LNG plant, arriving in Greece 12 days later, on 19 March. Spot volumes had a significant impact on average shipping time for LNG imports. Accordingly, average shipping time in March – with one spot cargo – almost doubled the average time required for LNG imports compared to January, when no spot cargoes were delivered (see Figure 4).

The relevant difference between the time needed for spot and long-term contracted LNG volumes to be delivered should be carefully assessed and analysed to avoid a false sense of comfort in countries with significant spare LNG importing capacity during periods of abundant supply.

Figure 4 - LNG imports by sales basis in Greece and average shipping time



Source: IEA (2017b)

During the Greek crisis, the increase in LNG imports was not enough to tackle the rapid demand growth in a timely fashion. Therefore, the country needed to adopt several demand-side measures to avoid forced interruptions of supply. These measures included:

(a) Requesting interruptible gas customers to reduce their consumption by at least 40%.

(b) Approving standard contracts for demand-side management.

(c) Fuel switching of gas-fired power generation plants to diesel oil where possible.

(d) Increasing hydropower generation.

(e) Voluntary management of gas-fired power plants according to TSO's guidance.

(f) Exercising interruptible electricity contracts.

Thanks to the adoption of these demand-side measures, together with the increase in LNG imports, no gas or electricity outages took place during the crisis. However, supplied natural gas demand during the crisis was below previously forecast demand. This means that without the reduction in consumption provided by demand-side measures the country could have experienced forced interruptions of supply. Thus, Greek events highlight once again that an abundance of supply – especially LNG – in the market, together with spare importing capacity, are not enough by themselves to prevent temporary tight situations.

It is therefore obvious that the SE Europe region needs a well-defined and pragmatic strategy for energy security which promotes resilience to these shocks and disruptions to energy supplies in the short term and reduced dependency on particular fuels, energy suppliers and routes in the long-term. Consequently, policy makers at national and regional level are faced with an important challenge as they must be prepared to inform the citizens of the available hard choices that reducing this dependency requires.

Looking at the broad energy security picture of SE Europe, we must by necessity confine our examination along two main axes. The **first axis** involves the security of energy supply for each individual country. For EU Members countries, this should be addressed in the context of EU's well defined energy security policy and on the basis norms already adopted since the summer of 2015 and now as part of the Energy Union provisions. In the case of non-member countries through Energy Community provisions and in Turkey's case through its association agreement, EU's energy security provisions, as latest experience has showed, generally apply. What no doubt needs to improve at this level is solidarity mechanisms so that at times of crisis EU's energy security mechanisms can be applied equally and with the same effect between member and non-member countries in the entire SE European region.

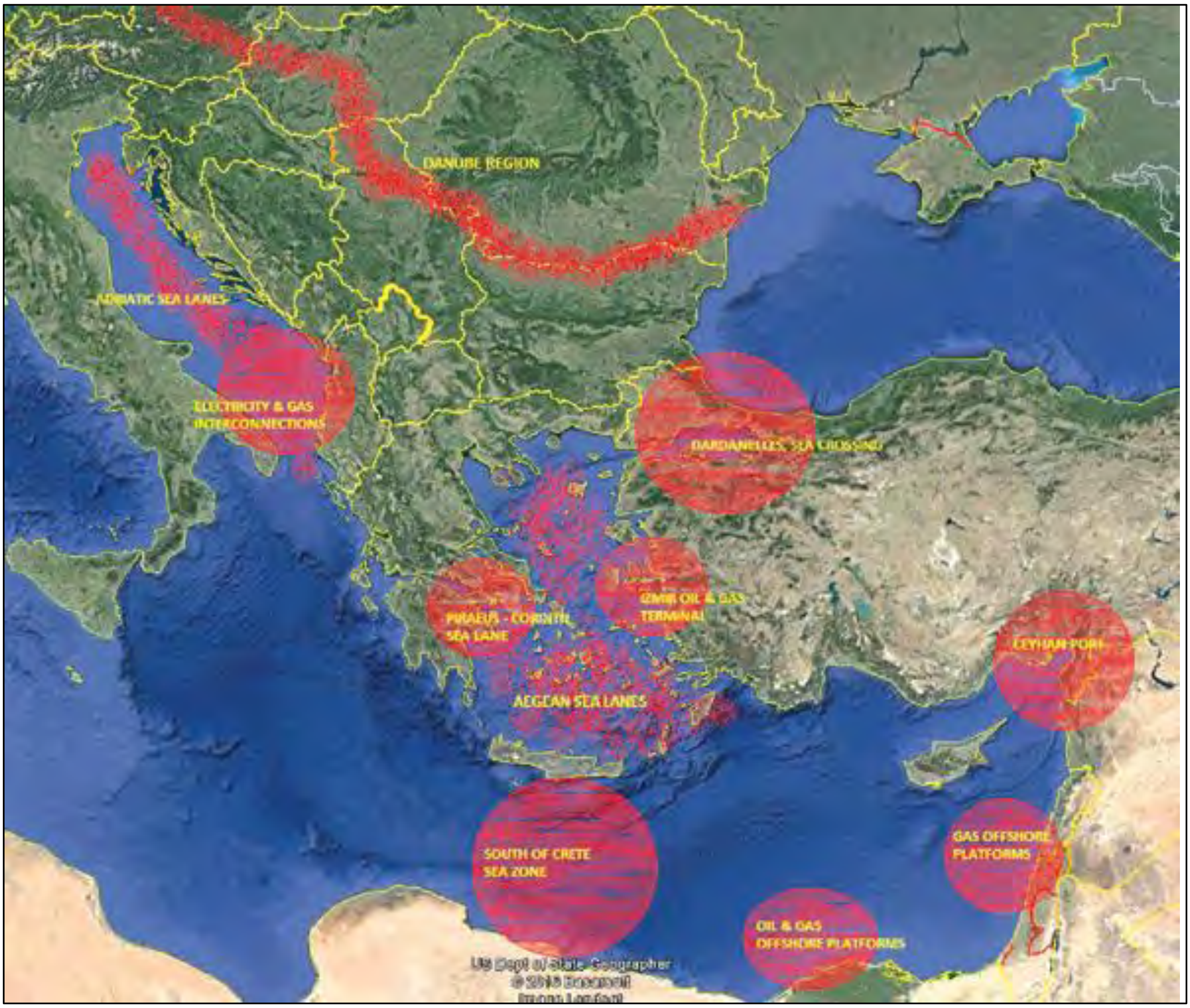
The **second axis** addresses our concern for the whole SE European area, treated as a single regional entity from an energy security perspective, and its crucial role as an East-West energy bridge. Over the last few years, energy security has emerged as a key issue for policy makers in Europe. In view of SE Europe's critical role, as an East-West energy bridge, in securing oil and gas supplies to Europe its "security" dimension has acquired a new importance.

A stable and abundant energy supply to EU countries is now accepted as a key policy objective especially since the EU imports 53% of all the energy it consumes at a cost more than €1 billion per day. In this sense, we should also concern ourselves with the ability of the region to secure the safe and continuous flow of oil and gas from the Eastern suppliers (i.e. from the Caspian region but also from Russia and tomorrow from Iran) through its land and sea areas to the Western markets.

In this context, the appearance of war conflict zones or hot spots (e.g. Eastern Ukraine, Crimea, Syria, Northern Kurdistan, Iraq) or the presence of energy choke points, such as the Bosporus, or vulnerable locations such the Ceyhan oil hub, the Piraeus- Corinth oil-gas sea lane and parallel land strip, are areas of security concerns where emergency plans must be in place in order to meet physical hazards or terrorist threats. Therefore, the consideration of the SE Europe region as an East West bridge should not be confined alone to the transit route concept (e.g. the South Corridor) but should also consider the various vulnerable key energy infrastructure locations.

These locations constitute potential **energy security hot spots** and as such should be properly identified (see Map 30), while also crisis management plans must be prepared in order to meet any emergencies whether these include physical hazards, large scale industrial accidents or terrorist actions. A cursory examination of such energy security hot spots across the region reveals potential vulnerabilities, involving disruptions of likely energy flows and in this sense a proper risk assessment analysis must be undertaken at both national and regional level by the competent national authorities and related international and regional organizations. Table 33 presents an initial and tentative list of such energy security hot spots to be found in various locations in SE Europe.

Map 30 – Energy Security Hot Spots in SE Europe



Source: IENE

Table 33 – Selected Energy Security Hot Spots in SE Europe

Location	Importance

Dardanelles, sea crossing	More than 3.6 mb of oil per day cross the Dardanelles and the Marmara Straits. The crossing presents high vulnerability in terms of potential accident and terrorist threats due to increased traffic.
Izmir oil and gas terminal and Ceyhan port and loading facilities areas.	Sizable maritime traffic of inbound and outgoing and loading facilities areas. Vessels over a restricted sea zone present high risk area and constitute a potential threat zone.
Piraeus-Corinth sea lane and associated land strip	High concentration of port facilities, oil and LNG terminals and refineries combined with high volume of maritime traffic presents high risk area and constitute a potential threat zone.
Danube region across Moldova, Romania, Serbia	Location of series of thermal power plants and coal yards across the Danube region in combination with high river traffic constitute a high risk area and potential threat zone.
Adriatic and Aegean sea lanes	Congested maritime traffic carrying oil and LNG cargoes could under certain circumstances present physical hazard threats and terrorist targets.
South of Crete sea zone	The presence of high migratory flows from North Africa to Europe combined with increased oil and gas sea traffic through the specific zone present potential terrorist threat.

Source: IENE

(a) Uncertainty over future Russian gas supply to SE Europe

Following the Russia-Ukraine gas crisis of 2009 and more recent conflicts in Ukraine as well as tensions between the EU and Russia, several studies on vulnerability in the event of disruption of gas supply via the Ukraine route have been published. Almost all studies focus on supply routes and take gas demand/consumption as given. In most cases, gas demand is even considered independently from the rest of energy supply structure in a particular country. In most analyses, SE Europe is identified as the most vulnerable territory in Europe. ENTSO-G data that are used in most of these analyses does not take into consideration the nature, sustainability and efficiency of gas demand[29]. The assumption is made that gas demand is the result of genuine commercial development and is economically justified. Unfortunately, that is not the case in South Eastern Europe where demand is historically built upon political priorities.

[29] The critical importance of energy efficiency was evident during the gas supply crisis in January 2009: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2010/11/NG17-ThePotentialContributionofNaturalGasToSustainableDevelopmentinSoutheasternEurope-AleksanderKovacevic-2007.pdf

The ongoing economic crisis tends to reduce industrial gas demand and preserve subsidized non-commercial demand. That makes relative weather sensitivity of demand even more difficult and effectively decreases infrastructure utilization rates. The market is undersupplied with underground gas storage capacity.

Industrial customers in SE Europe are not provided with many options in the case of gas supply interruption. This region is not served by any LNG terminal with truck, container or rail loading capability. The Marmara Ereglisi terminal in Turkey has modest truck loading capacity of 3x75 cm/hour[30] that is most likely consumed in the domestic market. The density of small scale LNG infrastructure in SEE territory is minimal[31].

The eventual development of a small scale LNG supply chain is also constrained by the lack of reloading capability at adjacent LNG terminals in the Adriatic and Mediterranean as well as a lack of LNG infrastructure in the Black Sea. Commitment to sizeable LNG re-gas capacity that may facilitate investment in competitive infrastructure seems to be a distant option as it depends on the sustainability of demand and eventual price competition from the incumbent supplier, according to Kovacevic.

Russia is the main supplier of fossil fuels to the European Union. The state-owned company Gazprom has a monopoly of Russian gas exports via pipelines and its revenues have made a substantial contribution to the federal budget. Europe is by far the largest importer of Russian gas and, despite Russia's recent efforts to diversify its customers (especially in Asia), the path dependencies created by geography and the already existing infrastructure mean that Europe will retain this role in the next decade (14). As Gazprom cannot easily replace the European market with other customers, it has an interest in defending its European market shares by competing with projects such as the Southern Gas Corridor. This is one of the key purposes of the Gazprom-sponsored pipelines in the Black Sea region, South Stream (may be revived) and Turkish Stream.

As with the Southern Gas Corridor, economic and political goals are closely interconnected in the Turkish and South Stream projects. If built, the pipelines will considerably reduce and eventually cancel Russia's dependence on Ukraine's transit pipelines for gas exports to Europe, and South Eastern Europe in particular. This would diminish Kiev's bargaining power vis-à-vis Moscow in the broader context of the Ukraine crisis. Furthermore, Russia has an

[30] Parada, L. (2016), "Best Practice Policy Guidelines for Small Scale LNG; Truck Loading", presentation, *Group of Experts on Gas, UNECE*, Geneva, http://www.globallnghub.com/custom/domain_4/extra_files/attach_213.pdf
[31] Small Scale LNG Map 2015, GIE, http://www.gie.eu/download/maps/2015/GIE_SSLNG_2015_A0_1189x841_FULL_wINFOGRAPHICS_FINAL.pdf

interest in using energy projects as a form of soft power to promote economic and political cooperation with Southern and South-East European countries. Italy, Greece, Bulgaria and Turkey (which are directly involved in Gazprom's proposed pipelines) are among Moscow's close political interlocutors in Europe and are keen on continuing their energy partnership with Russia.

Geopolitical factors play an important role in the gas infrastructure projects of the SE European region. Some of the actors' goals are easier to identify: (a) Russia wants to maintain its dominant position as supplier while diminishing reliance on Ukrainian transit, (b) the European Commission wants to differentiate EU imports away from Russia and receives political support from the US, as Washington wants to preserve its influence in Europe and stave off geopolitical competitors. The position of other actors is less defined. With support from their respective governments, Greek, Italian and Turkish companies are involved in both the EU- and Russia-driven projects. By doing so, they seek to maximise profits, pursue national energy security and attempt to strengthen their strategic position in international energy politics.

The geopolitical position of Azerbaijan is more nuanced than its role as key supplier of the Southern Gas Corridor suggests. On the one hand, Baku has keenly accepted the energy partnership with the West, which allows Azerbaijan to earn large revenues and assert its emancipation from Moscow's control. On the other hand, Azerbaijan continues to trade gas and maintain close contacts with Russia, as well as Iran. This is due both to economic/technical reasons and to broader security considerations. As a predominantly Shiite but secular state, Azerbaijan is particularly interested in cooperation with Moscow and Teheran in order to counter the spread of jihadism and the Islamic State (ISIS) in the South Caucasus.

Latest Anti-Russia Sanctions

The new package of anti-Russia sanctions introduced by the US Congress and signed by President Donald Trump in early August contains, among others, measures that target Russia's energy projects, including those implemented in SE Europe such as the European leg of Turkish Stream. There is wide speculation among energy experts and senior European officials that the new restrictions are aimed at squeezing Russian natural gas out of the European market to the benefit of US LNG supplies instead.

S&P Global Ratings (15) said that if US sanctions against Russia resulted in delays or abandonment of new pipelines projects, gas prices could grow, the gas supplies from Russia would risk being interrupted and the usage of underground gas storage and liquefied natural gas could increase. The agency added, however, that this was not the most likely scenario. In addition, it is still unclear how the sanctions might be put in place. For instance, the sanctions can focus on financing only, or include supplies of goods, services, and technology. They could also apply to pipelines under construction as well as to maintenance of existing pipelines, including those across Ukraine.

(b) Alternative gas supply sources and routes

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.

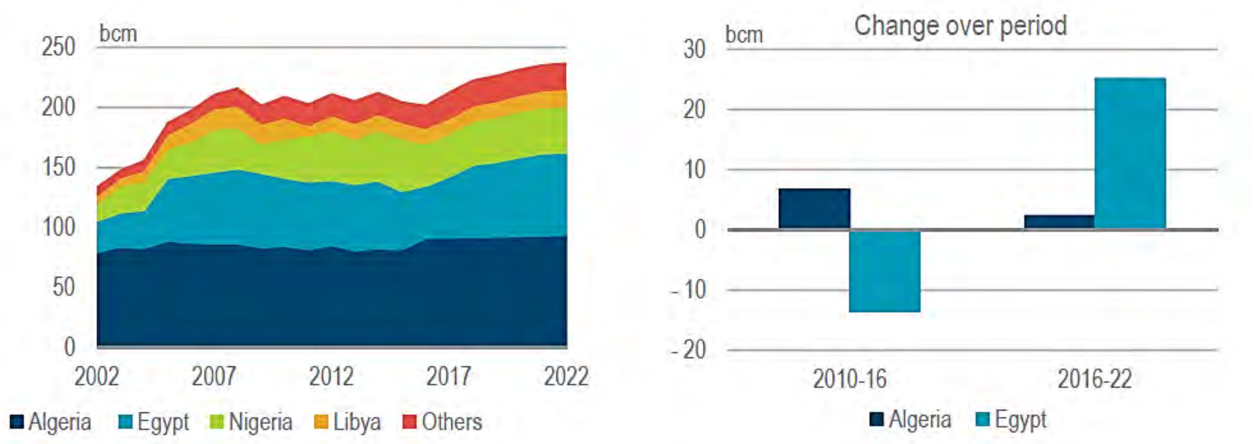
The internal European energy market is undergoing many changes, as the EU is moving towards its integration and liberalization. The integration is expected to increase the energy market effectiveness, create a single European gas and electricity market, contribute in keeping prices at low levels, as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

I. North Africa

The Middle East and North Africa (MENA) are the two regions which together account for around 40% of the global 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.

The outlook for total gas production in Africa is little changed from last year's IEA report. IEA's Gas Market Report 2017 expects an increase of 2.7% on average until 2022. The majority of the natural gas volumes are produced in Algeria, Egypt and Nigeria, representing around 85% of the total production of the continent. This report forecasts that at the end of the outlook period, around 70% of the production growth in the continent will take place in Egypt, coming from the Zohr field and the East and West Delta. Despite the declining trend seen in major maturing fields, Algeria, as the main gas producer of Africa, should be able to stabilise its output by bringing new fields into production.

Figure 29 – Africa gas supply by country, 2002-22



Source: IEA (2017a)

Algeria

IEA's report expects an annual average growth rate of gas production of 0.4% over the forecast period, growing from around 90 bcm in 2016 to around 95 bcm in 2022. In the short term, gas output will temporarily ramp up as a result of the start-up of Southern Fields projects such as Touat, Timimoun and Reggane. All three projects have been executed in partnership with International Oil Companies (IOCs) and will add around 9 bcm to the country's annual gas production. This modest increase implies that Algeria will be able to put a halt to the declining gas output seen for almost a decade. This steady decrease has been caused by declining mature fields, bureaucratic delays in the permitting process for the development of new fields, lack of foreign investors, and technical and infrastructural constraints, factors that will likely continue to affect gas production in the coming years.

Volumes produced from newly developed fields, as well as efforts to maintain a stable output from existing fields, are for the most part needed to satisfy rising domestic demand in Algeria. In the beginning of 2016, the expansion at the In Salah Southern Fields began with the aim of maintaining current output levels of the fields. The project is a joint venture among Sonatrach, BP and Statoil and involves the development of four dry gas fields: Gour Mahmoud, In Salah, Garet el Befinat and Hassi Moumene. The state-owned company also awarded the Japanese company JGC Corporation a USD 1.4 billion contract to improve the capacity of the facilities of the ageing giant Hassi R'Mel field, with the purpose of maintaining a production plateau. This field, the largest one in the country, is responsible for half of the natural gas output of Algeria.

In July 2016, the new minister of energy forecast an increase in Algeria's gas and oil production on the order of 30% by 2020. Given the lack of interest by foreign investors as a result of the weak business climate of the country and the restrictions for foreign investments, this target is likely unrealistic. New gas fields will partly compensate for the losses due to the maturing fields and lack of investments but won't contribute to a substantial growth of the output of the country over the forecast period.

Table 34 – Africa gas supply by country, 2002-22

Project	Producers	Volumes (bcm)	Planned start
Touat	Sonatrach, Engie	4.6	2017
Timimoun	Sonatrach, Total, Cepsa	1.6	2017
Reggane North	Sonatrach, Repsol, DEA, Edison	2.9	2017
Isarene (Ain Tsila)	Sonatrach, Petrotic, Enel	3.6	2018
Tinhert	Sonatrach	7	2018
Ahnet	Sonatrach	4	2019
Hassi Mouina	Sonatrach	1.4	2019
Hassi Ba Hamou	Sonatrach	4.4	2019
Menzel Ledjmet	Sonatrach	4.6	2019
Gassi Touil	Sonatrach	-	2019

Source: IEA (2017a)

Egypt

Currently, several natural gas field projects are being developed in Egypt that together could restore self-sufficiency towards the end of the forecast period. While the rest of the world has seen a structural slowdown in investments by energy companies, with increasing demand, Egypt is becoming one of the only countries able to attract multibillion-dollar investments in the upstream gas sector.

Table 35 – Major investments in gas projects in Egypt

Project	Companies	Investments	Volumes	Start production
Zohr	ENI	Initial investment USD 3.5 billion, total investments USD 6-10 billion	10 bcm 8 bcm	First phase 2017 Second phase 2019
West Nile Delta	BP	USD 12 billion	Maximum of 12 bcm	2017
East Nile Delta Atoll gas field	BP	Unknown	3 bcm	First phase 2018

Source: IEA (2017a)

In 2016, several IOCs operating in Egypt introduced programmes to accelerate the development of discovered fields. Among the new production schedules, the Italian major ENI aims to reach an output of 10 bcm before 2017, coming from six subsea wells that will be connected via a gas pipeline to the onshore plant at Port Said. Subsequently, another four wells will be added, increasing the output of the Zohr field to 18 bcm by 2019. At the end of 2015, BP decided to accelerate activities in Egypt, aiming to bring the offshore Atoll field in the East Nile Delta into production in the first half of 2018, three years after its discovery. In the first phase of the project, the company estimates it will be able to produce 3 bcm per year.

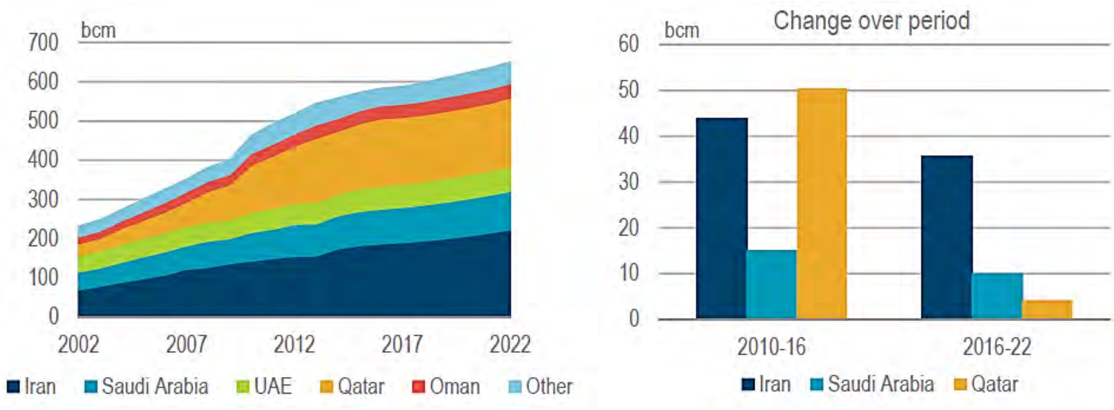
II. Middle East

IEA’s report also raises the forecast for gas production in the Middle East to account for higher output of dry gas mainly from Iran, Saudi Arabia and Qatar. The output is projected to grow by 1.8% on average, up from around 580 bcm in 2016 to 650 bcm at the end of the outlook period. These three countries will account for around 75% of the incremental gas production in the Middle East. In the case of Saudi Arabia, a significant percentage of the production is associated gas and therefore will fluctuate with the level of oil production.

Iran will account for the largest increase in production during the next five years, retaining its position as the biggest gas producer in the Middle East even though its gas exports remain negligible.

The development of the southern sector of Qatar’s North Field is not expected to make an impact on the Middle East’s supply forecast of this report. Qatar Petroleum (QP) announced in April 2017 that it would lift a moratorium in place since 2005 on further development of its offshore North Field. According to QP, this could result in the addition of 20 bcm per year of gas production. However, first gas is likely to come sometime in 2023 or later given the time needed to drill, produce and tie in new production facilities to onshore infrastructure. The only increase from Qatar forecast in IEA's report will come from the Barzan field.

Figure 30 – Middle East gas supply by country, 2002-22



Source: IEA (2017a)

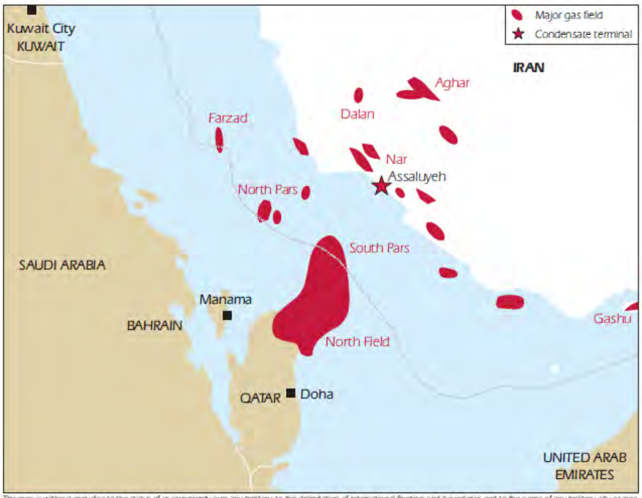
Further increases in the Middle East are expected to come from Iraq, where a gas gathering and utilisation project in the south is capturing gas that was otherwise flared. And in the United Arab Emirates, a country where the hydrocarbon industry is a pillar of the economy, the government is boosting production of gas to satisfy increasing domestic energy demand.

Iran

The outlook for Iran's gas production has improved since the IEA's Medium-Term Gas Market Report 2016. This year's report expects average growth of 2.9% per year, leading to production of almost 225 bcm by 2022, an increase of 36 bcm. Iran's economic prospects have been enhanced since most international sanctions imposed over its nuclear programme were lifted in January 2016 – US sanctions, however, remain in place. International oil and gas companies are now considering returning to Iran, though most are exercising caution. With 34 trillion cubic metres (tcm) of gas reserves, the world's second-largest conventional gas reserves, the government has offered up oil and gas acreage for foreign investment under a new contract model that replaced the unpopular buy-back scheme. In July 2017, France's Total became the first Western oil major to sign an agreement with Iran to develop phase 11 of the South Pars field. The project will have a production capacity of around 20 bcm per year, and the gas will go into the Iranian gas network for domestic use. Under the terms of the agreement, Total will operate the project with a 50.1% interest alongside Petropars (19.9%), a 100% subsidiary of NIOC, and the

Chinese state-owned oil and gas company CNPC (30%). Royal Dutch Shell also signed a memorandum of understanding with NIOC in December 2016 to explore areas of co-operation in oil and gas development. Neither Total nor Shell has finalised the preliminary agreements with Iran as yet.

Map 31 – South Pars and the North Field



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA (2017a)

In total, there are an estimated 4.5 tcm of undeveloped gas discoveries in Iran, including the undeveloped phases of South Pars, the North Pars and a number of other fields. However, it is unlikely that any of the remaining fields other than some phases of South Pars will produce any gas during the forecast period. NIOC is pressing ahead with further expansion of South Pars; 18 of the planned 24 phases have been fully or partially developed.

The additional gas volumes are allocated mainly for the electricity sector and industry, though a large volume is used for reinjection into oil fields for enhanced oil recovery. Volumes of gas for reinjection are expected to rise in the future as Iran prioritises increasing oil production in order to maximize revenues as it recovers from the restrictive sanctions and to prevent further declines from its older oilfields. While exact volumes of reinjected gas are not available, Iran is estimated to have injected 28 bcm annually for the purpose of secondary oil recovery since 2010.

Qatar

Qatar has an estimated 25 tcm of gas reserves, 14% of the world total. The small peninsula has the third-largest conventional gas reserves after Russia and Iran, nearly all of which are located in the offshore North Field, part of a structure that extends into Iran, where it is known as South Pars. The field is the world's largest non-associated gas deposit. Although an oil-producing member of the OPEC, Qatar early on recognised the value of developing its natural gas reserves and set itself a target of producing 100 bcm per year of LNG, which it achieved at the end of 2010. In 2005, QP, concerned about the impact of rapid development on the North Field's reservoirs, declared a moratorium on further development of the offshore field. Qatari officials said repeatedly in subsequent years that there were no plans to lift the moratorium.

Yet in a surprise move, in April 2017 QP announced that the moratorium would be lifted to allow exploitation of the hitherto untapped southern sector of the field, with the aim of producing at least 20 bcm of gas within the next five to seven years. QP has said that it has not yet decided whether the extra gas will be exported as LNG or as other products. The assumption adopted by the IEA's report, before the announcement of the lifting of the moratorium, was that Qatari production would slightly grow by 0.4% per year over the outlook period due to the start-up of the Barzan gas project, which received the green light just before the moratorium was declared.

Barzan, which is owned 93% by QP and the remainder by ExxonMobil, will produce around 20 bcm per year of gas when all phases are operating, originally scheduled for completion by 2020. Barzan gas is slated to supply the power and water sectors and to satisfy higher anticipated domestic demand for energy to support construction of new facilities needed to host the FIFA World Cup in 2022. Because of the moratorium, Qatari gas production had reached a plateau and was due to decline. Barzan, which was expected to come on line in late 2016 but was delayed and ran over budget, will help offset some of the decline. Without taking account of any additions to come from the southern sector of the North Field that is yet to be developed, IEA's report expects Qatar's production to rise during the coming years to around 175 bcm and stay at that level until 2022.

Saudi Arabia

Saudi Arabia has in recent years stepped up the effort to produce and process more gas as demand growth outstripped supply due in large part to generous consumption subsidies. IEA's report forecasts a growth rate of 1.8% per year in gas supply, though that may not be enough to satisfy the ambitious targets set out in the National Transformation Program (NTP 2020), a sweeping reform plan that extends to Saudi political, social and economic structures. Energy is at the heart of these reforms, with gas taking an increasingly central role in order to meet anticipated higher demand by the power and industrial sectors. By 2022, the country is expected to produce around 100 bcm per year.

Since early 2016, Saudi Arabia has lowered its crude oil production to comply with an OPEC supply cut, which has the Kingdom shouldering the bulk of the reduction. This will impact the volumes of associated gas produced, which in 2015 accounted for one-third of total gas output.

Increments in gas production will depend on the success of stepped-up exploration efforts by Saudi Aramco. Recent exploration has resulted in new oil and gas discoveries – the two gas discoveries are onshore – but it is not yet known when these will be developed. Recent rig counts show a record number of gas drilling rigs operating in the kingdom. The challenge will be to increase output in new gas fields with a complicated geology requiring higher costs for development. Gas exploration efforts in the Red Sea have so far not yielded any results.

Saudi Aramco is currently in discussions with several international oil companies about potential joint investments in gas projects both in Saudi Arabia and abroad, with a view to increase gas output rapidly. This would not be the first time that Saudi Aramco has opened up its upstream gas sector to foreign investors, though its Saudi Gas Initiative launched in 2001 did not result in new gas developments because of poor economics.

III. Eastern Mediterranean Region

Discoveries of natural gas in the eastern Mediterranean region have reshaped the regional energy map. The first significant natural discovery was made in 2009, when the US 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.

Syria

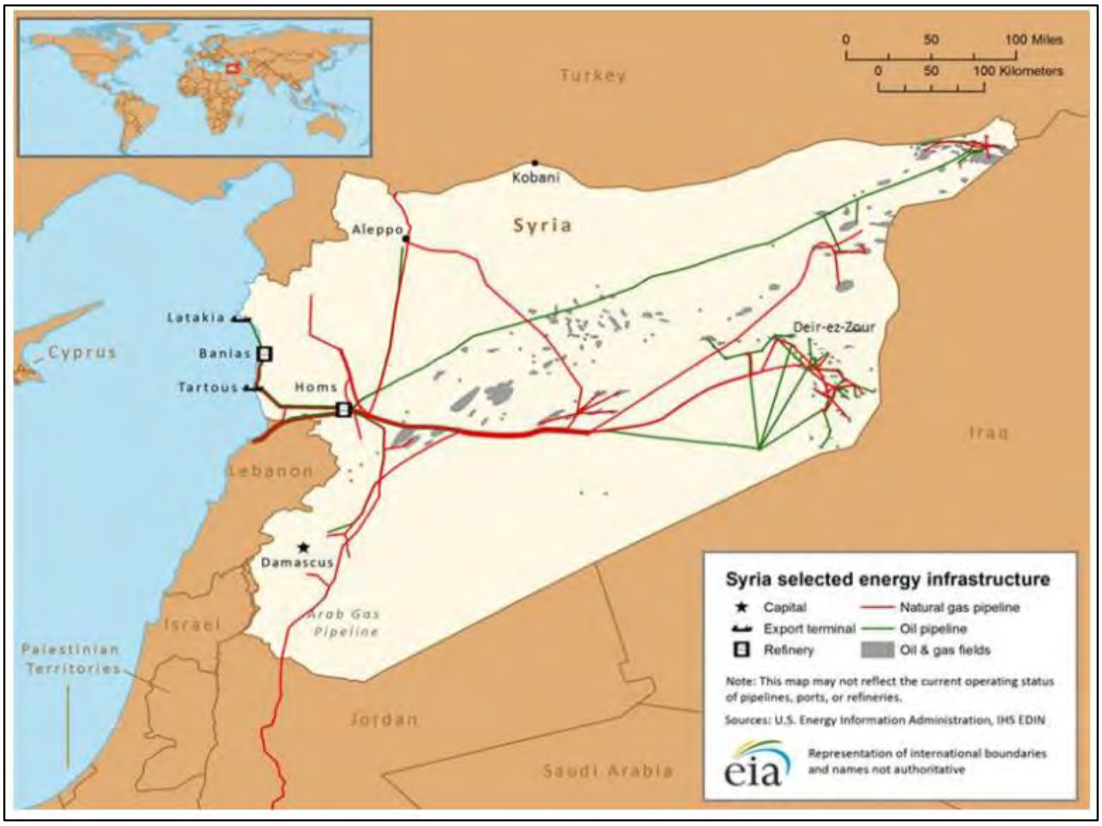
Currently, no countries in the region export natural gas. Syria was previously the eastern Mediterranean's leading oil and gas producer, however, with the country's oil and gas production declining since the start of the civil war in 2011. A report from the US Energy Information Administration (EIA)[32] states that Syria's energy sector is "in turmoil".

[32] http://www.eia.gov/beta/international/analysis.cfm?iso=SYR

The report highlights that Syria's energy sector has experienced several challenges as a result of conflict and subsequent sanctions imposed by the US and the EU. Damage to energy infrastructure (see Map 32), including oil and gas pipelines and electricity transmission networks, hindered the exploration, development, production, and transport of the Syria's energy resources. Syria has seen production fall sharply, to a minor sum in comparison to pre-conflict levels. The country is no longer able to export oil and thus, government revenues from the energy sector have decreased substantially.

Syria's gas sector has not been affected quite as severely by its political conflict as the oil sector. According to several sources, Syria held proved reserves of 8.5 tcf of gas, as of January 2015. The majority of Syria's gas fields are in the central and eastern parts of the country and the majority of gas is used by commercial and residential customers as well as in power generation.

Map 32 – Syria's energy infrastructure



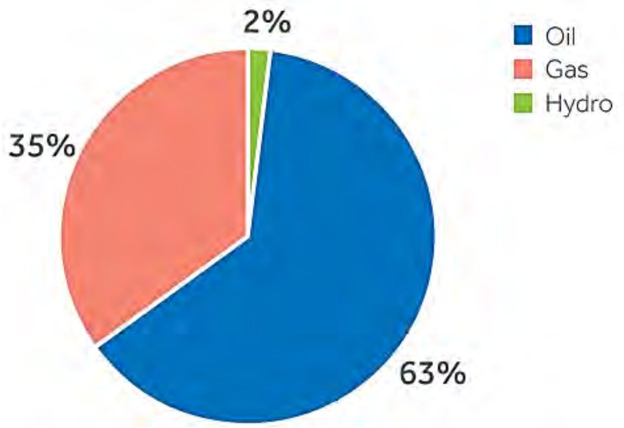
Source: EIA

In 2008, Syria became a net gas importer from Egypt; however, the current state of conflict has affected Syria's ability to import gas. The only source of gas imports (i.e. the Arab Gas Pipeline as shown in Map 33), became the target of attacks as the conflict intensified, forcing the pipeline to shut down. The country plans to convert all existing thermal power generation facilities to natural gas. Syria's energy mix is illustrated in Figure 31.

Map 33 – Arab Gas Pipeline

Source: EIA

Figure 31 – Syria's primary energy consumption by fuel (2013) (Total = 12.9 Mtoe)

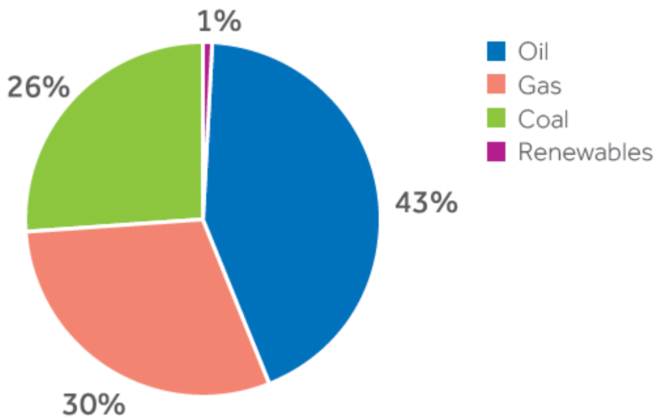


Source: EIA

Israel

Israel now has a growing gas industry. Recent discoveries of offshore gas fields have the potential to provide adequate amounts of energy to meet domestic demand, while allowing the country to export excess volumes. However, Israel's gas production outlook has worsened due to economic and political difficulties in securing export deals and growing regulatory uncertainty. Thus, Israel is not expected to become a gas exporter before 2020, limiting the potential scale of production increases. Robust domestic consumption growth will require 4 bcm of additional production, equivalent to average annual growth of 6% between 2014 and 2020, according to IEA's 2015 Medium-term Gas Market Report. Figure 32 illustrates Israel's energy mix in 2015.

Figure 32 – Israel's primary energy consumption by fuel (2015) (Total = 25.6 Mtoe)



Source: BP Statistical Review of World Energy 2016

In 2014, Israeli's gas production was almost fully dependent on the Tamar field (see Map 34) as production from the older Mari-B gas field has fallen to less than 1 bcm per annum. Tamar production started in April 2013, reaching 5.8 bcm for the entire year. Output rose further during 2014; the operator, Noble Energy, stated in Q12015 that production averaged 7.7 bcm per year since the field was brought on line, according to IEA's 2015 Medium-term Gas Market Report. The field production potential is above this level.

Map 34 – Eastern Mediterranean Oil and Gas Geography

Source: EIA

In 2012, Tamar's operator Noble Energy commenced a pre-front-end engineering and design (FEED) for a floating LNG (FLNG) project, but little progress has been made since then. The Leviathan gas field underpins much of Israeli gas exports potential. Located 47 km southwest of Tamar, it is the second largest gas discovery in the East Mediterranean Sea after Zohr field in Egypt, with estimate reserves more than twice those of Tamar. Leviathan is also operated by Noble Energy (see Table 36).

Table 36 – Gas discoveries in Israel

Name	Discovery year	Size (in bcm)
Noa	1999	2.8
Mari-B	2000	28
Dalit	2009	14
Tamar	2009	280
Leviathan	2010	620
Dolphin	2011	2.8
Shimshon	2012	17
Tanin	2012	34
Tamar Southwest	2013	26
Karish	2013	51
Royee	2014	91

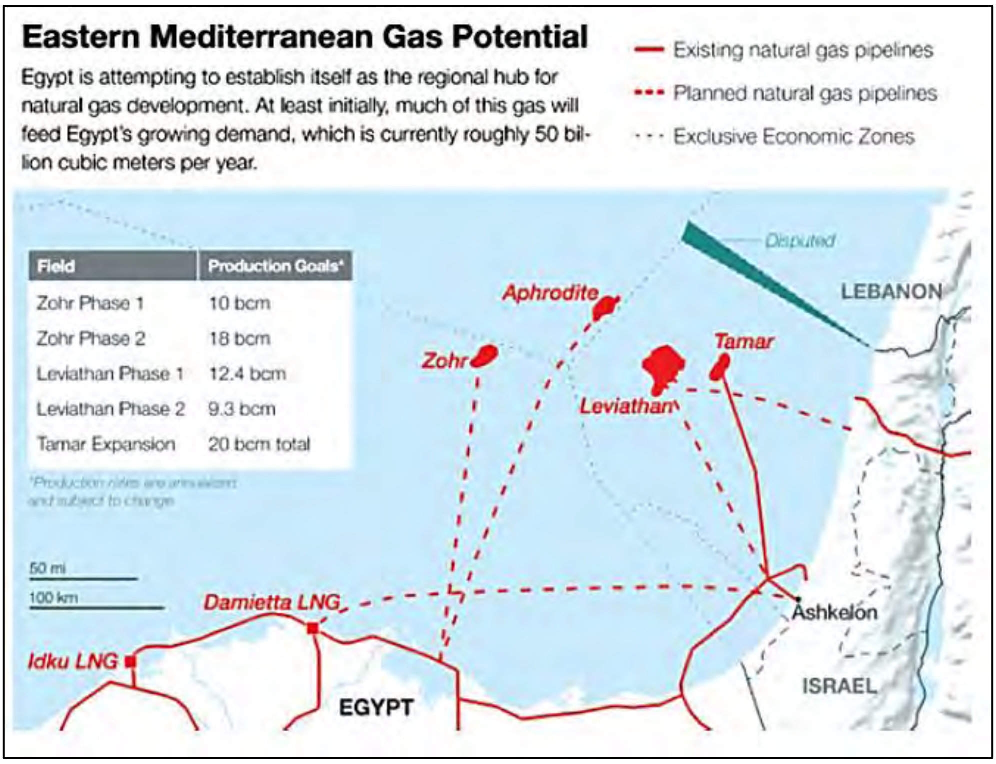
***Source: IENE, Stratfor*[33]**

Due to the size of its resources, Leviathan's development is necessarily tied to finding an appropriate export outlet. The operator is considering a FLNG option for this field as well, but progress has been slow. It is most unlikely that the facility will be on line by 2020, according to IEA. Leviathan's size and production potential are shown are shown in Maps 34 and 35.

An alternative option would be to develop pipeline gas exports to regional markets. Up to today, both Tamar and Leviathan consortiums have signed non-binding long-term gas supply agreements with companies in Egypt and Jordan. Moreover, when it comes to pipelines, the politics and fragile physical security of the region remains a hurdle to overcome.

[33] Stratfor (2016), "Egypt: The Eastern Mediterranean's Next Natural Gas Hub?", https://www.stratfor.com/analysis/egypt-eastern-mediterraneans-next-natural-gas-hub

Map 35 – Eastern Mediterranean Gas Potential



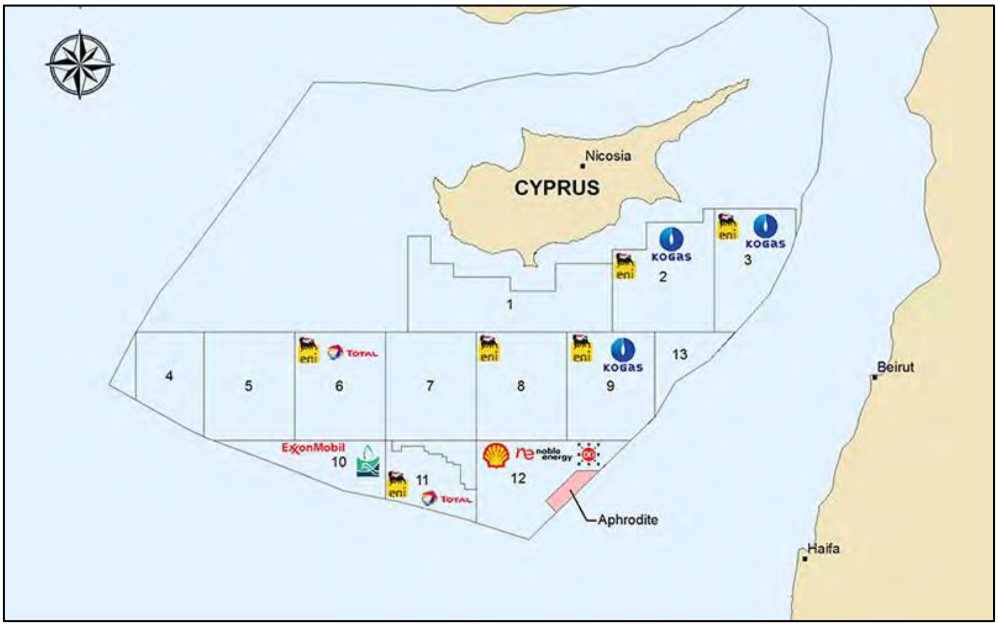
Source: Stratfor

Cyprus

Potentially, Cyprus holds a set of advantages in becoming a regional offshore gas hub; despite being further from Central Asian gas reserves, it is closer to Southern Mediterranean gas fields, which now appear as big, if not bigger, than those in the Caspian region. East Med's proven reserves amount to some 3.5 tcm, compared to Azerbaijan's 1.0 tcm, according to latest USGS data. Cyprus's small domestic market, with limited possibilities of growth, avoids making domestic consumption a cumbersome competitor to exports as in the case of Turkey and Egypt. In addition to owing domestic resources, Cyprus has a preferential lane towards the EU gas market thanks to its membership.

Speaking to the House Finance committee on October 30, 2017, Cyprus's Energy Minister George Lakkotrypis informed the MPs that the government is currently waiting to be informed by ENI on its planned drilling dates for next year. ENI has already asked for a permit to conduct environmental studies in Blocks 6, 8 and 3 and in the second half of 2018, ExxonMobil is also expected to conduct two drills "which will be crucial to developments thereafter", according to the Energy Minister. After having a clear hydrocarbons picture, the government will be able to take decisions about monetizing gas. Map 36 shows the key players involved in hydrocarbon exploration in Cyprus's EEZ.

Map 36 – Key players involved in the blocks of Cyprus



Source: Cyprus Hydrocarbons Company

Regarding the negotiations for the sale of Cypriot gas between the companies operating Block 12 off Cyprus's EEZ and the companies operating Egypt's two liquefaction terminals (at Idku and Damietta), Lakkotrypis said that in the last two years, 18 rounds of talks have been held – "nine for each terminal".

At the same time, the government of Cyprus is continuing its discussions and negotiations concerning the infrastructure required for landing the Aphrodite gas in Cyprus and liquefaction for export, while exploring all alternatives for Cyprus' gas exports, through collaboration with other countries in the Eastern Mediterranean region, especially Egypt.

Total and Eni are reportedly planning to start drilling in joint exploration Block 6 off the coast of Cyprus by the end of the year or in early 2018. Cyprus President Nicos Anastasiades met with Total's CEO Patrick Pouyanné on November 5, 2017, in Paris ahead of his meeting with French President Emmanuel Macron on November 6. The President of Cyprus said that Total's CEO Patrick Pouyanné informed him that the oil majors would move ahead with plans to drill in Block 6 despite disappointing drilling results from Block 11. "Yes, (Block 11) was disappointing in terms of quantity, but the results are very promising for future drilling. It confirmed the presence of hydrocarbons in the Cyprus EEZ, an extension of the Zohr field in Egypt," Anastasiades said.

In Block 11, an exploration well was recently concluded by ENI and 0.5 tcf of gas discovered which was characterized as non-commercially viable, but there are promising geological patterns. In addition, no future drilling plans have been announced so far. In terms of Blocks 2, 3 and 9, a 3D seismic survey was concluded. Mr. Dimitris Fessas, CEO of Cyprus Hydrocarbons Company (CHC), said that exploration drilling for Blocks 3, 6 and 8 is now planned for the first half of 2018 through 2 to 3 wells, while exploration drilling for Block 10 is anticipated in the second half of next year with 2 wells planned.

An important political factor that needs to be considered in Cyprus's plans is Turkey, which says that Cyprus has no right to explore for hydrocarbons since its decision to delineate its EEZ lacks legitimacy as long as the island remains divided, with the northern part inhabited by Turkish Cypriots. Such statements, backed by Turkish naval activity, have given rise to new tensions and have put on the spotlight the latest drilling programme which took place last July, a move which both Turkey and the Turkish Cypriots strongly oppose. It should be noted that the presence of French, US and other naval forces in the vicinity acted as a deterrent and prevented an escalation of tensions or even a possible military conflict.

At the same time, there is considerable criticism for successive government's failure to give priority to bringing gas onshore to Cyprus and gradually introduce it to the island's energy mix. Some experts talk of an inexcusable delay for Cyprus to take advantage of its newfound gas riches for local utilization which will have a positive impact and help its economy grow. Apparently, such criticism appears fully justified since the government has failed so far to produce a specific plan for transmitting gas from the Aphrodite field onshore.

Exploration failure in Cyprus would not necessarily be the end game, but the pace and risks would be different, and Cyprus's offshore developments would be more dependent on the success of Egypt and Israel. Israel has made large discoveries, has ongoing gas production and further field development is underway, but requires gas export markets and infrastructure if its offshore sector is to develop further.

As latest development, on December 5, 2017, Greece, Cyprus, Italy and Israel signed a memorandum of understanding for constructing an underwater gas pipeline from the Eastern Mediterranean region to Greece and Italy, which will allow the transportation of newly discovered Cypriot and Israeli gas reserves to mainland Europe, known as East Med pipeline project.

Greece's Energy Minister Mr. Giorgos Stathakis said that the East Med pipeline is "technically and economically viable", enjoys the support of all the other countries involved as well as the European Commission and would allow Israel and Cyprus to transport their proven hydrocarbon reserves as well as Greece's potential reserves to the European market.

East Med will connect Israel's Leviathan and Cyprus' Aphrodite gas fields to Greece and Italy. The initial estimate of the cost of the pipeline, which will be able to transport 12-16 bcm of gas per year, could reach €6 billion. The next step will be the signing of an intergovernmental agreement in Crete in the spring of 2018. More details about this project are available in page 69 in Chapter 5.

IV. Caspian Sea Region

Caspian gas production is expected to increase by about 40 bcm up to 2022. Turkmenistan exports to China over 2016-22 have been revised down significantly as line D from the Central Asia-China pipeline has been suspended. Azeri production is set to increase by 12 bcm by 2022, supplying Turkey and Europe.

The speed of the expansion of Caspian gas production will largely depend on China's demand requirements and the development of new markets for Turkmen gas, which is not expected within the time frame of IEA's report. Difficulty in financing and the Afghanistan security situation are hindering progress on the Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline. Progress on the Trans-Caspian pipeline to export Turkmen gas to Europe via Azerbaijan has yet to be realised. Moreover, Russian imports from Turkmenistan have stopped since the beginning of 2016, leaving China and Iran as the country's only export markets. Due to the gas contract disputes between Azerbaijan and Iran that started in 2016, it seems unlikely that gas exports to Iran will increase in the future.

At the time of writing, Azerbaijan's Shah Deniz Phase 2 field development is 90% complete, and the expansion of the South Caucasus Pipeline capacity is 93% complete. The project timeline aims at a mid-2018 production ramp-up to first export gas to Turkey and later, by 2020, to Europe. Shah Deniz Phase 3, Azerbaijan's other big offshore reserve, is unlikely to be commissioned before 2022 given the continuing low price environment for oil and gas. A final investment decision (FID) on Absheron field development is expected to be taken by Total towards the end of 2017, and the preliminary timeline aims at a 1.5 bcm production start by 2019-20.

A series of recent developments regarding the aforementioned Vertical Gas Corridor concept have demonstrated a consolidated approach to ensure interconnectivity on the South-North axis and to promote integrated gas transmission systems, hopefully in a more competitive price environment, for Southeastern and Central and Eastern member-states, as well as for Eastern European and Western Balkan countries aspiring to EU entry.

To start with, the fourth meeting of the Central and South-Eastern Europe Connectivity (CESEC) High Level group, held on September 28, 2017, resulted in the establishment of two working groups, consisted of the involved gas transmission system operators and supported by the European Commission, one of which will assume responsibility for putting into effect the idea of a vertical gas pipeline route extending from Greece to Bulgaria, Romania and Hungary. As for the other, it will oversee implementing reverse flow on the Trans-Balkan pipeline system.

A few days earlier, the 182km-long Interconnector Greece-Bulgaria, the first link in the Vertical Corridor northward supply chain, had been issued the sought-after construction permit on Bulgarian territory by the Ministry of Regional Development and Public Works. What's more, Greek Public Gas Corporation (DEPA) formally agreed with utility company Gastrade on participation in the development of the FSRU in Alexandroupolis, northern Greece, projected to become a new entry point of multi-sourced gas into SE Europe. The new terminal could potentially provide access for US LNG into the Balkans. State-owned Bulgarian Energy Holding is set to participate in the project whilst US LNG producers such as Houston-based Tellurian Energy or Cheniere Energy are also eyeing a stake in the project. Both pieces of infrastructure are directly complementary to each other.

Considering the foregoing, it is deemed useful to look in more detail into the origins and evolution of the envisaged Vertical Corridor project and its facilitating role in the efforts to transport additional diversified gas quantities, provided both from the Caspian Sea and US shale imports, towards the isolated, poorly liberalized and often dominated by a single supplier (namely, Russia's Gazprom) southeastern and central and eastern European markets.

To decode the rationale behind the European Commission's objectives for the energy landscape of the SE European region, one should first go back to the commercial and technical reasons why the Shah Deniz consortium opted for TAP instead of Nabucco West, back in 2013. The Turkey-Austria Nabucco pipeline was supposed to help increase the gas liquidity of Baumgarten gas hub, reaching to those member-states mostly affected by the

2006 and 2009 Russian-Ukrainian gas disputes. However, its multi-kilometer network didn't manage to assuage concerns over excessive costs and was finally aborted, as it failed to attract adequate nonbinding bids for its initial 10 bcm capacity during the crucial months before the announcement of the FID. On the other hand, the selection of TAP as the third segment of the $45 billion Southern Gas Corridor gas value chain is justified by the fact that its significantly shorter 878km-long route across Greece, Albania and Italy is argued to be cost-effective, since it allows Europe to utilize reverse flows towards multiple directions, while its underground storage facilities may ensure a secure and reliable gas supply in case of future energy shortages.

With the help of swaps and reverse flows, Trans Austria Gas pipeline (TAG) could carry Azeri gas from TAP to Central and Eastern Europe, while Transitgas pipeline could transfer Caspian resources via Switzerland to Germany and France. Moreover, TAP contributes to Bulgaria's energy diversification thanks to its capability of sending reverse flows to the Kula-Sidirokastro line and IGB. Finally, the proposed Ionian Adriatic Pipeline (IAP), another yet connection to TAP, will cover gas demand in ill-supplied markets, such as Kosovo, Montenegro, Bosnia and Herzegovina, Croatia and, of course, Albania, who has all these years kept in motion a continuous dialogue process with TAP AG in hopes of developing its national grid.

Consequently, TAP's potential to connect with other planned pipelines, like IGB, has given a push to coordinated intergovernmental cooperation for the realization of the Vertical Corridor. The term implies a comprehensive gas interconnectivity strategy that intends to facilitate gas transportation from Greece through Bulgaria, Romania and further on to Hungary and Ukraine, among other likely to be concerned countries, taking advantage of the south-to-north reverse flow option. Furthermore, in accordance with EU's determination to bolster the security of supply through the completion of a single energy market, it may well speed up the gasification of the Balkans and Eastern Europe, simultaneously with a sustainable integration of the gas transmission systems of all interested and involved parties, as Caspian Policy Centers stresses (16).

The idea dates to 2014, when the government representatives of Greece, Bulgaria and Romania inked a joint declaration in support of a new Vertical Gas Corridor that would guarantee 'uninterrupted bidirectional supplies' form one country to another through the implementation of EU-financed Projects of Common Interest, in the form of both pipeline interconnectors and LNG terminals, thus complementing the core Commission's policy towards a Southern Gas Corridor. In that same year, TAP AG and ICGB, IGB's contractor, co-signed a Memorandum of Understanding on technical collaboration for the development of strategic infrastructure in Southeastern Europe, as a proof of the close correlation between the two pipeline projects. In July 2017, gas transmission system operators from Greece (DESFA), Bulgaria (Bulgartransgaz), Romania (Transgaz) and Hungary (FGSZ), as well as the ICGB consortium, affirmed eagerness to activate a vertical gas supply route by signing a fresh agreement in Bucharest. In 2016, a similar MoU had been signed in Budapest by DESFA, Bulgartransgaz, Transgaz and Ukrainian counterpart Ukrtransgaz, a fact indicative of the broad geographical spectrum of the initiative.

Apart from existing and prospective gas interconnectors awaiting to be supplied by Shah Deniz gas and whoever else eventually books TAP's additional open-access 10 bcm capacity after 2020, the Vertical Corridor route is at the same time heavily relied upon many LNG terminals on Greece's north Aegean coast, following the latest trend of a steady growth in global LNG demand at approximately 12% per annum, as Tellurian SVP, Tarek Souki, recently estimated at a conference. This is good news for the forthcoming wave of US LNG cargo deliveries that will try to path their way to the Eastern European region, aside from traditional principal destinations in Latin American, Mexico, Asia and the Caribbean. Nevertheless, since US shale has to be liquefied, shipped across the Atlantic and re-gasified at the EU's doorstep, its cost unavoidably rises to around $7/MMBtu, meaning that contract holders will have to pay some $2.5 to 3.5/MMBtu in liquefaction fees, whereas Russian gas pipeline prices at the German border average at a little over $4/MMBtu. Even though US LNG currently seems practically unaffordable for Balkan and Eastern Europe allies, hopes are high that prices will soon start to converge. Besides, the competition created by US companies' presence in Central Europe is believed to prompt regional low-cost providers, like Gazprom, into a future rethink of their gas pricing methods.

Greece began importing and storing primarily Algerian LNG in 2000, at its Revithoussa LNG terminal, located on an islet west of Athens. Thanks to this piece of infrastructure, Greece was left unaffected by the supply shortages of the 2009 Russian-Ukrainian energy crisis and was even able to cover neighboring Bulgaria's gas demand for a two-day period, at the time. The second upgrade of Revithoussa, ongoing since 2010 and scheduled to be finalized by spring 2018, as confirmed by the Greek energy Minister, will result in the construction of a third LNG storage tank with a 95 tcm capacity, that will increase the total storage capacity of the plant to 225 tcm.

Full activation of the Vertical Corridor is interlinked with the progress of the Alexandroupolis FSRU in Northern Greece, as well as to the Revithoussa upgrade, because further LNG capacity will contribute to the familiarization of all concerned countries with spot gas trading, a thus far neglected alternative, because of the prevailing situation of long-term piped gas contracts in the region. Moreover, US shale imports, conjointly with Caspian gas supplies via the Southern Gas Corridor, can act as a game changer for the security of supply in Central and Southeastern Europe, enabling this geographical group of member-states and Energy Community parties to comply with the Energy Union goals concerning the obligatory access of each and every one of them to at least three different energy sources.

The Contribution of the Alexandroupolis FSRU to the Energy Security of SE Europe

Greece looks to be in the process of creating the necessary preconditions so as to emerge, by early 2021/22, as a regional gas trading hub for countries in its immediate vicinity. For one thing, it has already in operation since 2007 an active interconnector with Turkey (with more than 5.0 bcm annual capacity) and has initiated the establishment of gas interconnection systems with Turkey, through TAP, ITGI and Turkish Stream, with Bulgaria, through IGB, with FYROM through the interconnector from Nea Messimvria (Greece) to Stip (FYROM), and eventually with the Eastern Mediterranean, through the homonymous pipeline project, conjured up to transport Israeli, Egyptian, Cyprus, and, at some point, Lebanese, gas towards Italy, provided that economic and political challenges are overcome. It has also moved forward with the upgrading of existing and the development of new LNG-related facilities. And, last but not least, it has opened previously dormant frontier offshore hydrocarbon exploration in the Ionian Sea and Crete, in order to unlock potential indigenous resources. Whether or not the adjacent countries of Turkey and Bulgaria will discern inherent advantages from a strategic energy partnering with Greece, in line with the European dictat on supply diversification, remains to be seen. Meanwhile, it is anticipated that Caspian supplies together with potential US LNG will enhance Europe's energy security, especially the areas of Europe that are heavily dependent on a single supplier.

In this context, the contribution of the Alexandroupolis FSRU project to the energy security of the SE European region will be of great importance. Taking into account Greece's recent energy crisis in early 2017 and the prevailing recessionary economic climate, it is anticipated that the implementation of this project will enhance the diversification of gas supplies, will introduce new pricing methodology and will promote competition not only in Greece but also in the wider SE European gas markets, which now rely mainly on Russian gas volumes.

As already analysed, the Alexandroupolis FSRU project will be able to link, feed into, support and provide alternative gas supply to the aforementioned expanded South Corridor and will facilitate access to the Western European gas markets and the West Balkans gas ring. Also, the Alexandroupolis FSRU can largely contribute to Greece's economy (it will considerably upgrade the economy in the area of Alexandroupolis supporting the local labor market and economic activities in a wide range of sectors) as it will feed into the Greek National gas transmission system and to the Greek market, thus enhancing the national security of supply and offering alternative supply options to Greek consumers at competitive cost. Furthermore, it will provide an additional LNG option in the entire region, taking also into account that this project will be the only new gas infrastructure project in the region which will not rely on Turkey as a transit country.

The project's geopolitical importance has grown as a result of the Ukraine crisis, the abandonment of the South Stream pipeline and Russia's decision to discontinue transit flows through Ukraine as of 2019, which has raised the level of concern within the EU with regard to the energy security and the uninterrupted gas supply of European markets, especially of those which lack alternative supply sources and routes, such as the countries of SE Europe.

In this context, the Alexandroupolis FSRU project has been nominated as one of the 27 most critical projects for the European Supply Security Strategy (DG Energy, 28.05.2014), and has been included in the CESEC initiative conditional priority list slated to contribute to the main corridor of gas supply to SE Europe from Greece to the North, identified within the recent LNG and storage strategy prepared by the European Commission.

V. LNG options

LNG supply directly competes with pipeline gas at re-gas points and in sectors that are better served by LNG without immediate re-gasification such as transport or flexible power generation.

Black Sea and Danube

As Compressed Natural Gas (CNG) shipping options are overcome by small LNG technology development, small scale LNG emerges as an option for shipping gas across the Black Sea. That option is further enhanced by the recent advancements in small scale LNG technologies for liquefaction, shipping, and use. In addition to trade with Black Sea coastal markets, small scale LNG could use navigable rivers to access markets in Belgrade on the Danube or Kiev on the Dnieper.

Suitable shipping solutions are already available using self-propelled ships and articulated tug-and-barge arrangements. Such transport systems may deliver LNG (and other energy intensive products such as fertilizers) to (or from) ports such as Belgrade, Kiev, Rostov-on-Don, Baku, Batumi, Ruse, Bucharest, etc. With appropriate level of fleet standardization and reasonable volumes, transport costs may be comparable to open sea shipping. Available modern shipping standards are far more efficient than the traditional river-to-seagoing fleet proven during the1970s and 1980s in this region. The main sources of LNG in the Black Sea are ports on the Russian coast, Georgia (gas from Azerbaijan and eventually Turkmenistan) and Turkey (gas from Iran or Iraq) or Black Sea off shore sources.

Although the transit of loaded large-scale LNG carriers through the Bosporus straits seems to be excluded due to safety reasons, Turkey is considering the construction of the Kanal Istanbul (see Map 37). If that channel is built to proposed dimensions it is likely to facilitate navigation by standard LNG carriers. However, that is to be considered as a long-term goal, according to the Oxford Institute for Energy Studies (20).

Map 37 – Proposed routes for the Istanbul Channel

Source: Esas Yatirim[34]

For completeness, it is considered that a more feasible, small scale channel may be introduced following the same route (or one of the proposed routes) instead of, or before, or in parallel to the large-scale scheme. "Small scale" in this context may be understood as the navigation standard of the Danube Iron Gates locks. This would provide an opportunity

[34] http://esasyatirim.com/kanal-istanbul-guzergahi-icin-5-alternatif-var/

to transport LNG by river-to-seagoing ships from the LNG terminal(s) in the Sea of Marmara to all destination in the Black Sea area including navigable routes of large rivers adjacent to the Black Sea (Danube, Dnieper, Volga-Don system and Caspian Sea).

New developments in small scale LNG technologies provide an opportunity for the introduction of a traded Black Sea LNG market that may be considered as a competitive gas-to-market option for most of the gas sources in the region. Eventual development of a suitable Istanbul channel may provide a link between such a Black Sea LNG market and the international LNG markets.

Mediterranean and Adriatic

The Mediterranean LNG market is an integral part of the international LNG market. There is a number of LNG sources in the Mediterranean itself and more LNG is available via Suez and Gibraltar. Receiving terminals in Greece and the Adriatic could have slight transport cost advantages in accessing the LNG spot market.

However, such advantages are not sufficient to cover the pipeline transport costs of eventually moving gas from LNG terminals in the Balkans to consumers in Central Europe as pipeline infrastructure toward the coast is relatively limited in capacity. Atlantic and Baltic coast terminals will have better access to these markets.

In similar manner, Italian LNG terminals are better positioned to serve the Italian market as well as a considerable part of Central Europe via Slovenia.

Black Sea or Mediterranean LNG could be transported inland by railways (containers) or inland waterways (Danube) directly to large scale consumers or inland wholesale terminals to supply transport demand.

Box 2: Poseidon Med II LNG Bunkering Project

Poseidon Med II LNG Bunkering Project is a continuation of Poseidon-Med and the Archipelago-LNG projects, which all together are part of the Global Project aiming to take all the necessary steps towards adoption of LNG as marine fuel in East Mediterranean Sea, while making Greece an international marine bunkering and distribution hub for LNG in SE Europe. The Action will build on the achievements of the above mentioned projects as well as on the results of Poseidon Med I, which delivered the Master Plan for LNG as a marine fuel in the Mediterranean region.

The specific objectives of the Action are to: (a) facilitate the adoption of the regulatory framework for the LNG bunkering, (b) design the extension of Revithoussa LNG terminal, (c) design and construct an LNG-fuelled specific feeder vessel, (d) implement technicaldesigns and plan approvals for the retrofit/new building of LNG-fuelled vessels and for additional ports' infrastructure for bunkering operations, (e) examine potential synergies with other uses of LNG, (f) develop a sustainable LNG trading and pricing pattern and (g) develop financial instruments to support the port and vessel installations. But the major objective is the distribution of LNG in six main ports (Piraeus, Patra, Heraklion, Igoumenitsa, Limassol and Venice), as the following Map illustrates.

Map 1 – Poseidon Med II LNG Bunkering Project

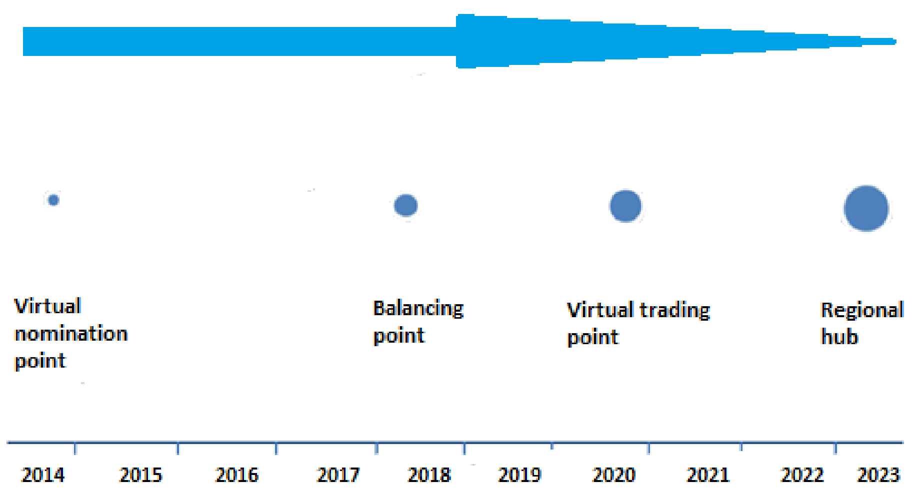
Source: DEPA

Poseidon Med II is financed by the Connecting Europe Facility (CEF), a key EU funding instrument that supports trans-European networks and infrastructures in the sectors of energy, transport and telecommunications. This project will last for 5 years with the participation of 26 companies from three EU member states (Greece, Cyprus and Italy). The start date of this Action was June 2015 and the end date is December 2020. Its estimated total cost is roughly €53 million and the percentage of EU support is 50% (€26.6 million).

9. Regional gas hubs and their role in enhancing energy security

Following the significant role the Alexandroupolis FSRU project can play in SE Europe, this chapter highlights the opportunity for the creation of a natural gas hub in Alexandroupolis in Northern Greece. In its 2014 study (21), IENE stresses that Greece launched the Virtual Nominations Point (VNP) in December 2013, 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. The virtual point is set to serve as the Greek Balancing Point System. 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 33 – Proposed roadmap for the development of a natural gas hub based in Greece



Source: IENE

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 Alexandroupolis gas hub will have access to European prices through TAP. The development of infrastructure, such as the planned underground gas storage facility in South Kavala, the FSRU facility in Alexandroupolis and the IGB, among others, will facilitate the access of network users to the Greek gas market, and will contribute in initiating trading activities in the Greek gas hub. It should be noted that 3rd party non-discriminatory access to these infrastructures is already available. 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. However gas transactions in the interconnection point are strongly depended on the regulatory framework and the third – party access regime of each country of the region.

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.

Therefore, a regional gas hub will be a hub that is distinguished from existing gas infrastructure and local gas markets with regulated prices as well as existing long-term supply contracts. It would serve an entirely liberalized transport fuel market that was physically constrained to allow access of international market players. It would be established by private commercial players that are granted the rights needed to acquire, build and operate appropriate physical infrastructure by more than two governments, observed by the European Commission and supported by international financial institutions. Its operation would be in compliance with the EU Third Energy Package. It would facilitate trade in gas and various related commodities and securities.

It is interesting to contemplate the pricing dynamics that may affect the regional gas hub price level and formation. US LNG would likely be diverted to this hub as soon as it offers sales prices above NBP or TTF (see below). This opportunity is likely to create an effective price cap over excessive pricing from any other source of gas available to the hub, and would contribute to the alignment of pricing between the hub and NBP/TTF. Trading gas at peak demand may provide a premium to investors in that trade. Hub-to-hub competition is a form of market coupling that would produce alignment of prices.

(a) 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 SE Europe (see Figure 34). 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 SE Europe, there are exchanges with long history, such as the Athens Exchange Group and the Istanbul Exchange that could offer gas futures trading. The existing Istanbul Energy Exchange established in March 2015 and includes electricity market operations (e.g. day-ahead market, intra-day market, balancing market), while gas market operations are expected to start in April 2018.

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 SE 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.

Figure 34 – SWOT analysis for a gas hub in SE Europe

Source: IENE

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.

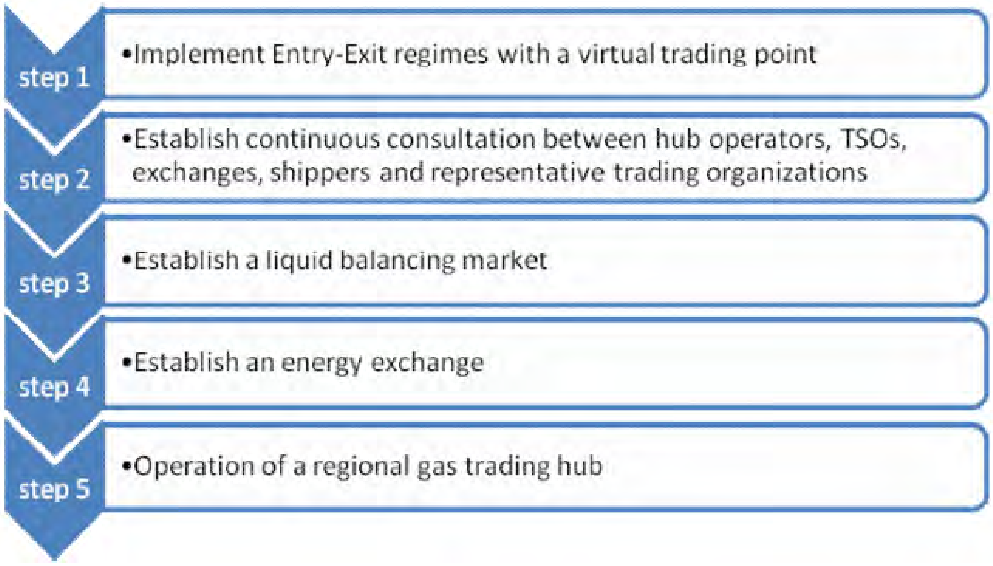
(b) A Roadmap for Setting Up A Regional Gas Hub

Elaborating on the roadmap presented in Figure 35, for the establishment initially of a Greece-based gas trading hub, probably in Alexandroupolis, which could also serve the wider SEE 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. However, in the case of Bulgaria and Serbia, progress for the creation of wholesale gas markets is seriously lagging behind. Recently, the Bulgarian Energy Regulator took significant steps towards the full liberalisation of the natural gas market. In December 2016, the Bulgarian Energy Regulator adopted legislative amendments to the Rules for Trading of Natural Gas and the Rules for Access to the Gas Transmission and/or Gas Distribution Networks and the Natural Gas Storage Facilities. Moreover, it adopted new Rules for Balancing of the Natural Gas Market. 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 2020 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). It is worth noting that Greece will also set up its own energy exchange in 2018 despite the fact that it will initially operate as a power exchange. Finally, it must be stressed that the roles of the TSO, the hub operator and the exchange should be clearly defined.

Figure 35 – Next steps



Source: IENE

On September 14, 2017, a Memorandum of Understanding between the National Natural Gas System Operator (DESFA) and Athens Exchange Group was signed. The cooperation aims mainly to bring together expertise and infrastructure, owned by the two companies, ensuring relevant economies of scale for a more efficient and faster achievement of the strategic goal, which is the development of a wholesale gas market in Greece and its expansion to SE Europe within the framework of integration of the internal EU gas market.

The first stage for the operation of a wholesale market is the set-up of a balancing market and a balancing platform, in which the TSO will buy/sell gas quantities required for balancing the network. In that way, market liquidity is increased a reference gas price is formed on daily basis, based on the prevailing conditions of supply and demand. In this direction, DESFA has already put underway all the necessary actions on an institutional and technical level, aiming to have the Balancing Platform in operation at the beginning of 2018.

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 - 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 2020.

IENE's study also concluded the broad concept for the establishment of two regional gas hubs (one in Thessaloniki, which can now be in Alexandroupolis and one in Istanbul) to handle between them the anticipated gas volumes that will be generated following the opening up of the regional gas market. At this stage, the consideration of the above two locations is entirely arbitrary since locations will at the end be decided by the hub operators in cooperation with the exchangers. However, as a working proposition, it is useful to be able to refer to points of reference in the broader vicinity. One should further consider that in our case, at least as far as Greece is considered, the most likely outcome will favour the development of a virtual hub, hence location will be irrelevant.

A lot will also depend on the trading conditions that each energy exchange will offer in terms of charges, speed of execution and clearance of orders and transparency and on the other hand on the hub operator whose role is of great importance for the physical aspects of the trading and especially for the reliable delivery and "firmness" of traded volumes. Furthermore, one of the critical questions is whether the regulatory framework and third-party access regime of all the countries in the region is allowing for such transactions.

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 Alexandroupolis 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).

(c) 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 and 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:

(i) The minimum level of investment required in gas infrastructure work to enable the availability of adequate gas quantities to be traded through the hub.
(ii) 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)
(iii) The anticipated volume of gas to be traded through the hub and the forecast churn ratio[35].

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. Alexandroupolis FSRU

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

[35] Probably the most important measure of a gas hub's commercial success is the churn ratio, which is the multiple of traded volume to actual physical throughput: a measure of the number of times a 'parcel' of gas is traded and re-traded between its initial sale by the producer and the final purchase by the consumer. The churn rates are an excellent measure of a hub's real liquidity and success and are a parameter used in most commodity and also financial markets.

Table 37 – Cost of planned gas infrastructure projects

Natural gas project	Cost (€mn)
IGB	220
TANAP	805 (with TANAP's cost corresponding only to Turkey's European ground route)
TAP	4,500
South Kavala UGS	400
Alexandroupolis FSRU	370
Total	**6,295**

Source: IENE

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 2020. 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, Russia (via South Stream at IGB) and Italy - North Africa via TAP's reverse flow.
   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 (i.e. IGB, IGT, Bulgarian Greek Main Pipeline) and gas demand projections for 2020, one could safely assume that some 1 to 1.5 bcm of gas will be available for trading as early as 2020, rising to 6 and possibly to 10 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.

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 38 – 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 1.000m^3 for 2Q2014 for Gazprom gas deliveries in SE Europe (exchange rate used EUR/USD =0,7338).

Source: IENE

From the data presented above, especially that concerning infrastructure investment and the anticipated volume of gas trade, it becomes clear that the setting up of the specific gas trading hub – which in the first phase will connect Greece, Bulgaria and Turkey – requires major infrastructure investment of the order of €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 2020, 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 (i.e. marginal gas quantities) which will become available from main gas importers, by placing bids through the “hub” for both physical quantities and gas futures. Such trading activity will inevitably lead to the formation of a new climate of competitive prices, exerting pressure on traditional suppliers to revise their contract prices.

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

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

(d) Trading Activity and Prices at European Gas Hubs

Similar to the first quarter of 2017, liquidity on the main European gas hubs decreased in the second quarter of 2017: **total traded volumes** amounted to around 10,400 TWh, 16% less than in the same period of 2016, based on data provided by the European Commission in its Quarterly Report on European Gas Markets (22). Traded volumes decreased year-on-year in the Austrian (-13%), Belgian (-25%), Dutch (-17%), German (-14%), Italian (-11%) and UK (-15%) hubs; only the French hubs showcased an increase (20%). Analysts suggested that the smaller liquidity is explained by lower volatility and a lack of trade on seasonal products.

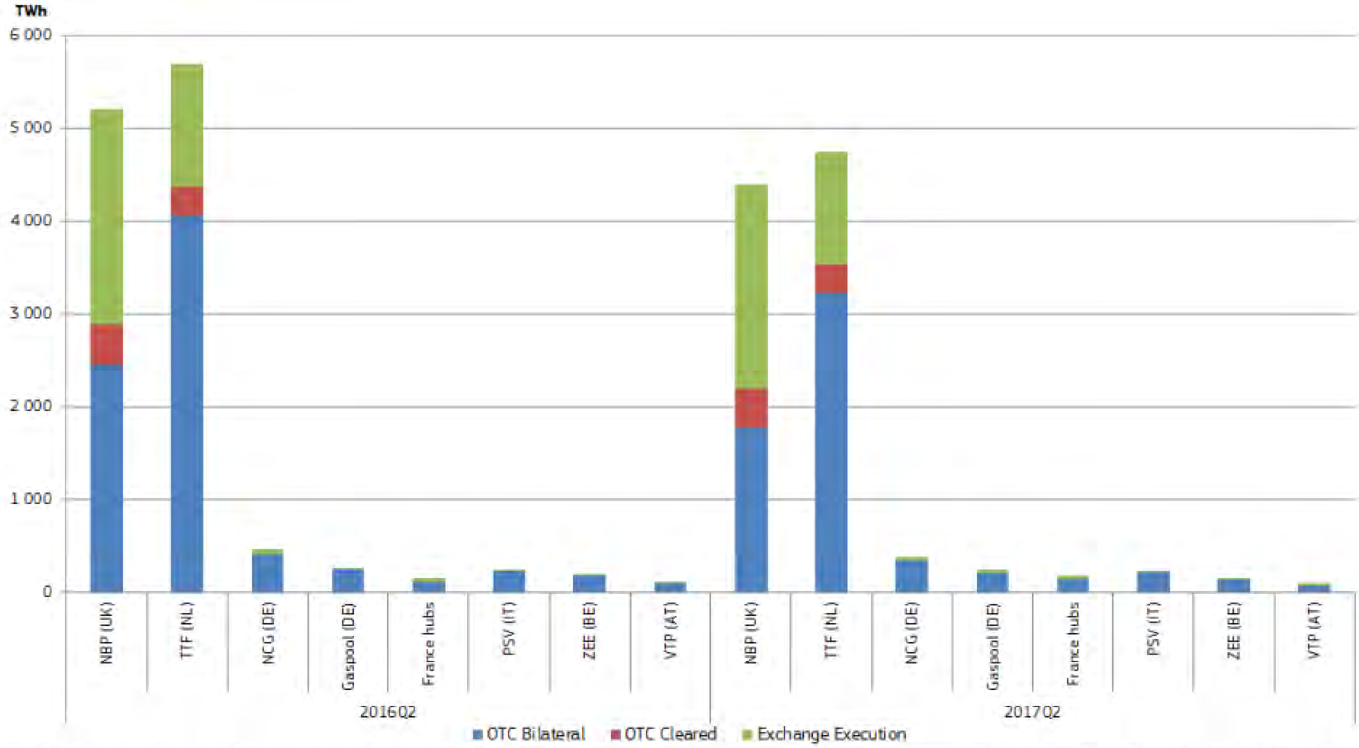
TTF and NBP continued to have a dominant position in the second quarter of 2017, covering 46% and 42% of hub traded volumes, respectively. These shares are identical with those observed a year earlier. With the increasing trading volumes, French hubs gained some ground: their share increased from 1.3% in the second quarter of 2016 to 1.8% in the same period of 2017.

On the UK NBP hub, half of total traded volumes were executed directly on an exchange in the second quarter of 2017. This share was 25% on the Dutch TTF hub, 23% at the French hubs, 21% at the Austrian hub, 13% at the German hubs but only 1% at the Belgian and Italian hubs. At the Austrian hub, the share of exchange trade was significantly higher than a year earlier (6%).

At EU level, OTC markets remained the main trading venue, but their share slightly decreased from 69% in the second quarter of 2016 to 66% in the same period of 2017. 11% of OTC volumes were cleared at a clearinghouse in the second quarter of 2017, up from 9% in the same period of the previous year.

In May, the German Federal Cabinet adopted a draft regarding amendments to the Gas Network Access Ordinance, according to which the two existing German gas market areas, NCG and Gaspool, are to be merged as of April 1, 2022. The merged hub, with its increased liquidity, is expected to have a stronger position in the European gas market.

Figure 36 – Traded volumes on the main European gas hubs in the second quarter of 2016 and 2017



The chart covers the following trading hubs: UK: NBP (National Balancing Point); Netherlands: TTF (Title Transfer Facility); Germany: NCG (NetConnect Germany) and Gaspool; France: PEG (Point d'Echange Gaz); Italy: PSV (Punto di Scambio Virtuale); Belgium: Zeebrugge beach, Austria: Virtual Trading Point (VTP).

Source: European Commission

European hub prices significantly increased between September 2016 and January 2017, supported by cold weather (especially when compared to the previous year), strong demand in the power sector, depleting stocks, the outages of several French nuclear reactors, low LNG imports in Northwest Europe and uncertainty about the Rough storage site in the UK. In February and especially March, relatively mild weather and growing LNG imports helped prices to reverse.

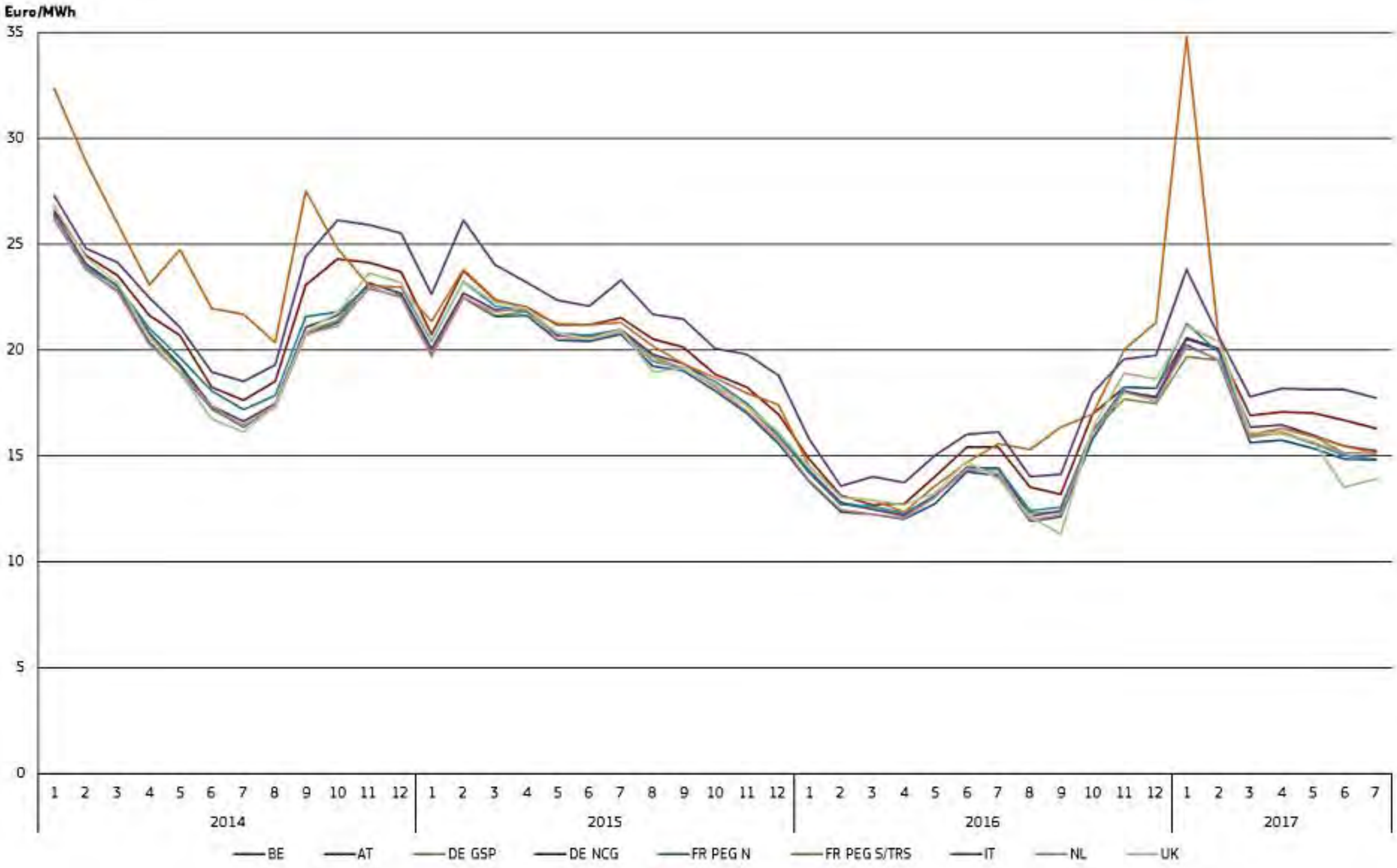
In the second quarter, European hub prices averaged around 16 Euro/MWh, roughly 18% more than in the same period of 2016. A late cold spell and strong injection demand provided some support to prices in April but in May and June prices decreased, helped by higher temperatures and rising LNG imports.

During the past winter, gas at the UK hub traded at an usually high price compared to mainland Europe: in the November 2016-February 2017 period, the average difference compared to the Dutch TTF hub was nearly 1.0 Euro/MWh. Low stock levels after the outage of the Rough site, the UK's largest storage facility and low LNG imports caused supply tightness in the UK and the country had to rely more on pipeline imports from Norway and mainland Europe. Increased import flows were fostered by the relatively high prices in the UK. The trend turned with the arrival of summer: in June, gas at the UK hub traded 1.6 Euro/MWh cheaper than at the Dutch hub. With no injection demand at Rough, the UK market was oversupplied, putting pressure on day-ahead prices. The Belgium-UK Interconnector was closed for annual maintenance between 14 and 28 June; as the surplus gas could not leave the country, the discount of NBP to TTF reached up to 5.0 Euro/MWh in this period.

Prices at the Italian PSV hub remained relatively high in the second quarter of 2017, with an average premium of 2.5 Euro/MWh above TTF, the Dutch hub. Reduced imports from North Africa and strong storage injections provided support to Italian prices

In France, the premium of TRS over PEG Nord reached exceptional levels, averaging 13.5 Euro/MWh in January 2017 when high seasonal demand coupled with low LNG imports (and the persistent capacity restrictions on the north-south pipelines within France) caused supply tightness in the southern part of the country. By early February, milder weather and additional LNG cargoes allowed the situation to ease and the premium of TRS over PEG Nord has practically disappeared. In the second quarter of 2017, TRS traded only 0.3 Euro/MWh above PEG Nord on average. In this period, the average price at the PEG Nord hub was slightly lower than at TTF, helped by a significant increase in LNG imports to the terminals in northern France.

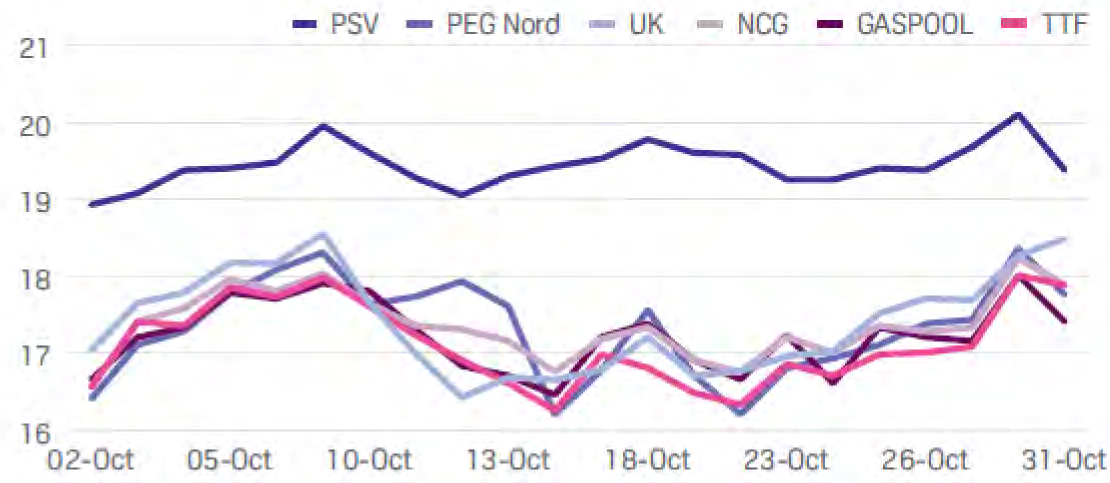
Figure 37 – Wholesale day-ahead gas prices on gas hubs in the EU



Sources: European Commission, Platts

Figure 38 depicts the European day-ahead gas prices during October 2017. European gas pricing in northwest Europe shrugged off seasonal trends in October, posting mild losses from September on the back of strong pipeline natural gas imports last month allowing for further storage injections ahead of the withdrawal period, according to S&P Global Platts.

Figure 38 – Day-ahead gas prices in October 2017 (EUR/MWh)



Source: Platts

Figure 39 looks at the development of forward prices one, two and three years ahead in comparison to the development of the day-ahead price on the Dutch TTF. For most of 2014, there has been a situation of contango[36], whereby closer to the present date prices are lower than prices for future deliveries. With seasonally high stock levels and ample physical supply, spot prices significantly decreased in the first half of the year, while higher forward prices reflected the general uncertainty about future developments, in particular the Russia-Ukraine conflict.

Day-ahead and forward prices have been more or less at parity in 2015 but in 2016 the forward curve moved higher. In 2016, the year-ahead price was on average 0.7 Euro/MWh more expensive than the day-ahead price but in certain days of August the difference exceeded 2 Euro/MWh. In this period, the oil price rise which started in late January 2016 provided support to forward prices

In the last quarter of 2016, this premium of forward prices over day-ahead prices have practically disappeared. In fact, from mid-October to mid-February 2017, day-ahead prices have been consistently higher than year-ahead prices. In January-February 2017, the difference averaged 1.0 Euro/MWh as day-ahead prices were supported by below-average temperatures while a looming LNG oversupply put pressure on forward prices. From March,

[36] Contango: A situation of contango arises in the when the closer to maturity contract has a lower price than the contract which is longer to maturity on the forward curve.

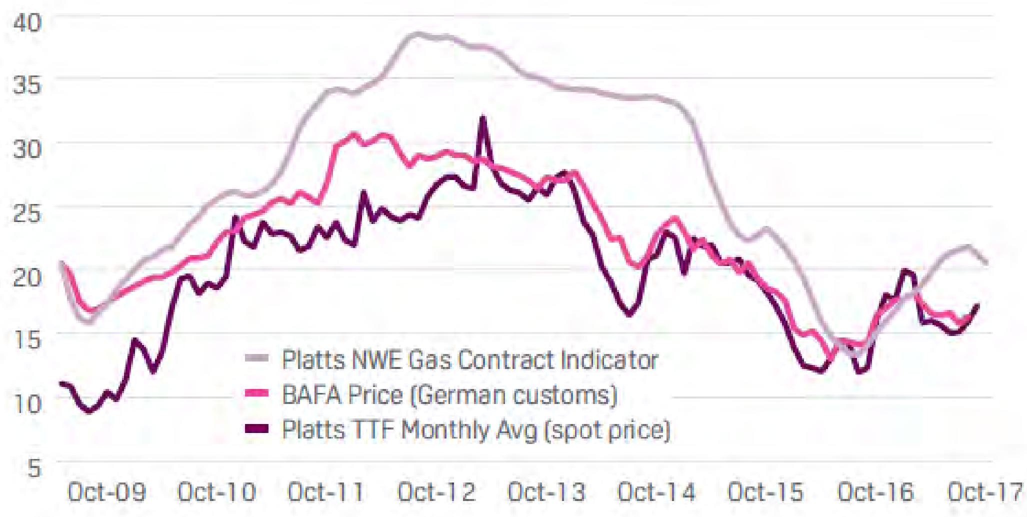
forward prices has been again slightly above day ahead prices, with the difference averaging 0.4 Euro/MWh in the second quarter of the year.

Figure 39 – Forward gas prices on the Dutch gas hub

Sources: European Commission, Platts

The Dutch TTF spot posted a month-on-month fall in October 2017, shrugging off seasonal trends, as generally mild temperatures allied to continuing firm demand bulked up storage stocks before the start of the withdrawal period. TTF spot delivery averaged Eur16.932/MWh during October, down from the September average of Eur17.188/MWh but still a solid 8% higher than the Eur15.743/MWh recorded in October 2016, according to S&P Global Platts data. The TTF November contract averaged Eur17.909/MWh during October, suggesting that TTF spot pricing will increase month on month as demand starts to build as the winter season progresses.

Figure 40 – Long-term vs Short-term gas prices (EUR/MWh)



Source: Platts

Tables 39 and 40 show the Northwest Europe oil-indexed gas indicator for October 2017 at 20.511 Eur/MWh, highlighting a fall of 0.696 Eur/MWh, compared to the previous month and the European spot gas as percentage of oil-indexed gas. Table 40 illustrates the past 13 months of TTF average flow-date day-ahead gas prices. It also shows the development of the Platts NW Europe Gas Contract Indicator, which indicates a typical price for long-term, oil-indexed gas supplies. The final column shows the average TTF flow-date day-ahead gas price as a percentage of the long-term, oil-indexed gas price.

Table 39 – Platts October 2017 NWE Oil-indexed gas indicator

	Eur/MWh	Change M-1	p/th	$/MMBtu
Current Month	20.511	-0.696	53.003	7.107
Month-Ahead	19.929	-0.582	51.499	6.905
Month-Ahead +1	19.910	-0.019	51.450	6.898

The Monthly NWE oil-indexed gas contract indicator is a modeled price reflecting the cost of gas sold in NW Europe under a traditional long-term sales contract indexed against fuel oil and gasoil. The model does not include any adjustment for discounts from contract renegotiations. Prices are originally calculated in Euro per MWh, then converted to p/th and $/MMBtu using current exchange rate.

Source: Platts

Table 40 – European spot gas as percentage of oil-indexed gas

	TTF avg Eur/MWh	NWE GCI Eur/MWh	TTF/GCI %
October 17	16.932	20.511	83
September 17	17.188	21.207	81
August 17	15.954	21.813	73
July 17	15.102	21.580	70
June 17	15.051	21.306	71
May 17	15.643	20.745	75
April 17	15.997	19.801	81
March 17	15.875	18.837	84
February 17	19.723	18.142	109
January 17	19.940	17.763	112
December 16	17.635	16.754	105
November 16	17.980	16.000	112
October 16	15.743	15.078	104

Source: Platts

Comparing the prices of different contracts for gas in the EU

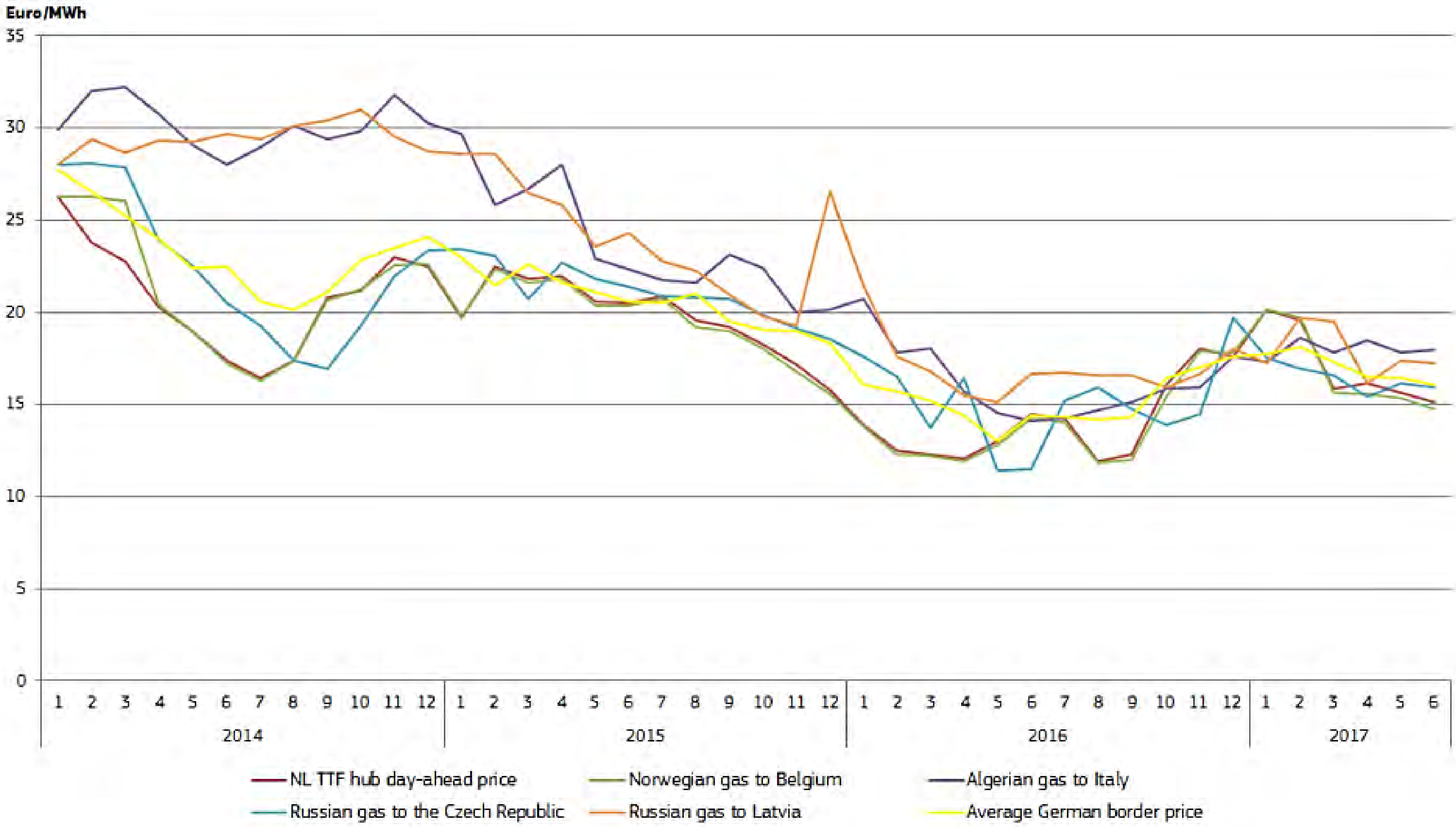
Figure 41 compares a selection of estimated border prices of gas deliveries from the main exporters to the EU – Russia, Norway, and Algeria. Estimated border prices showed a clear declining trend over 2015 and the first half of 2016. Driven by the oil price drop observed in the second half of 2014, oil-indexed prices fell faster than hub-based prices, leading to a significant price convergence in mid- 2015. From the last quarter of 2015, however, the difference between the prices of various contracts increased again, although not to levels seen in previous years.

The oil price rise starting in the end of January 2016 is reflected in oil-indexed prices from the summer of 2016 while hub prices continued to fall. As a result, in the third quarter of the year oil-indexed prices became noticeably more expensive than hub prices. In the last quarter, however, hub prices sharply increased and other contracts have grown to a lesser extent. As a result, unusually, the Dutch TTF price was the highest in this period among those depicted on Figure 41, exceeding even the typically oil-indexed prices of Russian gas to Latvia and Algerian gas to Italy.

In the first quarter of 2017, both hub prices and oil-indexed prices increased compared to the last three months of 2016. Hub prices were supported by a relatively cold winter while oil-indexed prices grew in the wake of the gradual rise of oil prices during 2016. The different prices have been rather volatile, often moving in the opposite direction but, looking at the average quarterly prices, there was no significant discrepancy between hub prices and oil-indexed prices.

In the second quarter of 2017, hub prices gradually decreased while oil-indexed prices remained elevated, supported by the delayed impact of the oil price rise seen in 2016. In June, the typically oil-indexed prices of Russian gas to Latvia and Algerian gas to Italy were 2-3 Euro/MWh more expensive than the price at the Dutch TTF hub.

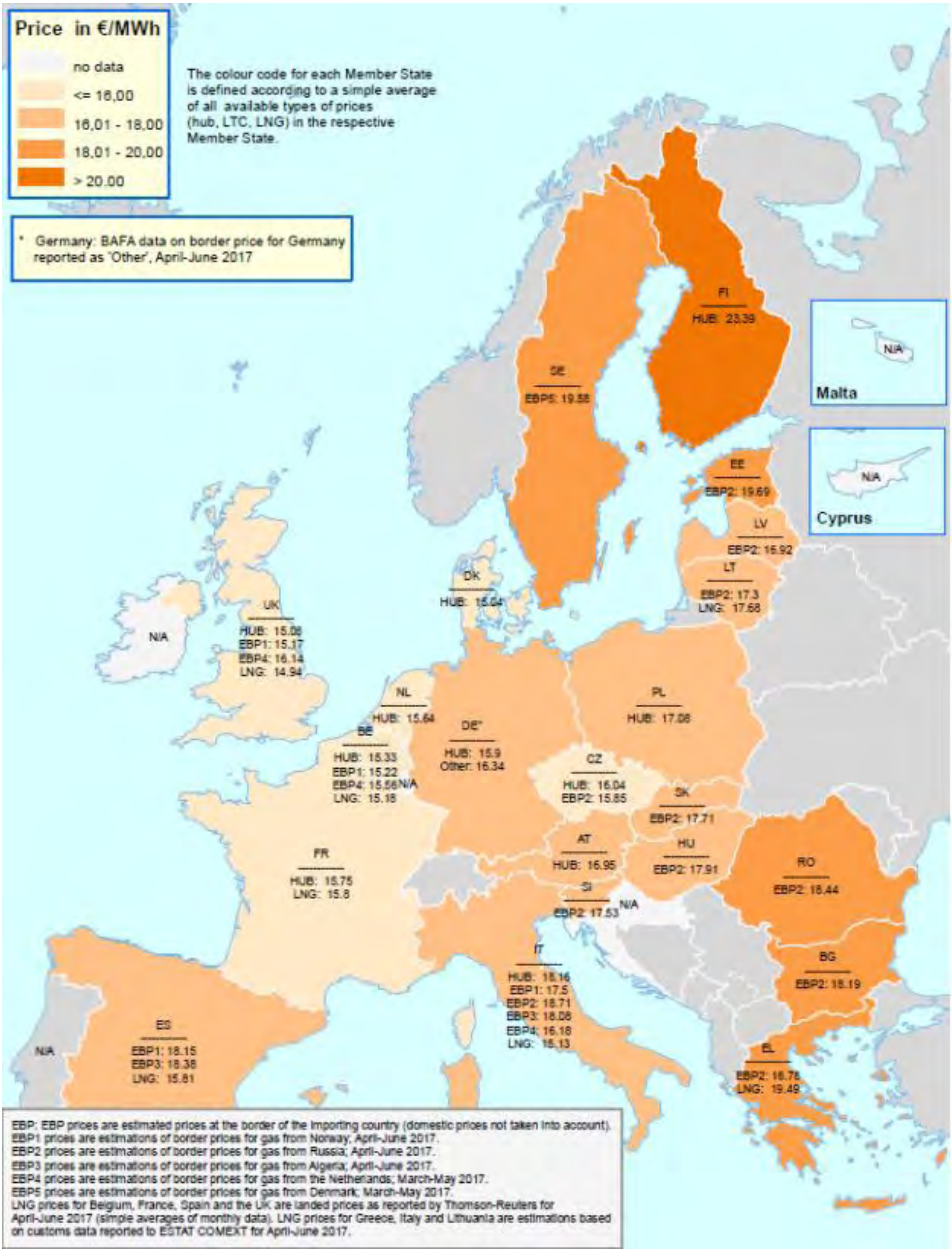
Figure 41 – Comparison of EU wholesale gas price estimations



Note: Border prices are estimations of prices of piped gas imports paid at the border of the importing country, based on information collected by customs agencies, and are deemed to be representative of long-term contracts.

Source: European Commission, Platts

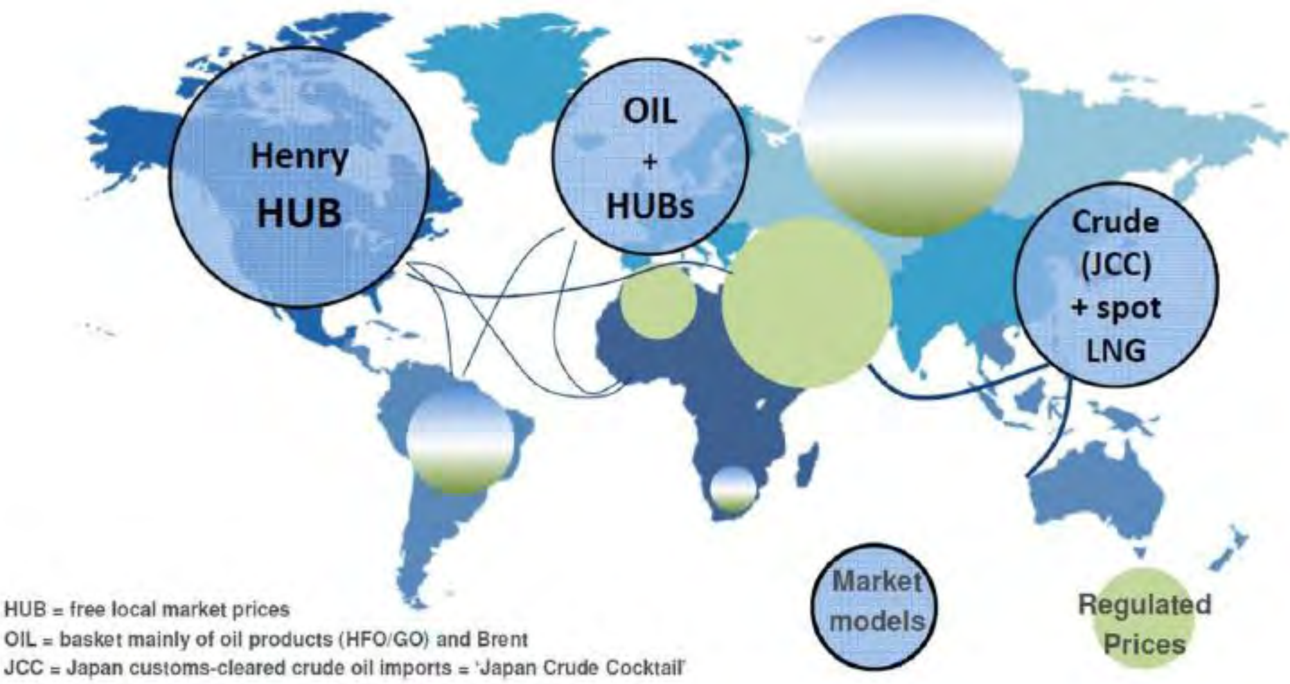
Map 38 – Comparison of EU wholesale gas prices in the second quarter of 2017



Source: European Commission, Platts

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.

Map 39 – 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 in Europe increased from 15% in 2005 to 66% in 2016 while oil indexation decreased from 78% to 30% during the same period, based on data provided by the IGU 2017 Wholesale Gas Price Survey (23).

In Southeast Europe, a very small amount of gas-on-gas competition is shown (see Figure 42), from 2014 onwards, in Croatia but in no other country. There is a large element of RCS[37]

[37] Regulation: cost of service (RCS): The price is determined, or approved, formally by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.

in Romania, with the lower level of OPE[38] in 2009 and 2010 a consequence of lower demand for imports in Romania and the rise in 2012 reflecting a switch from bilateral monopoly (BIM) in Bulgaria, where until 2010 there was payment in kind for transit (BIM) which then became a cash payment with the gas being purchased under the same OPE terms as the other imported gas. OPE fell back again in 2013 and 2014 as imports declined in Romania, before stabilising in 2015.

Gas-on-gas Competition vs Oil Indexation

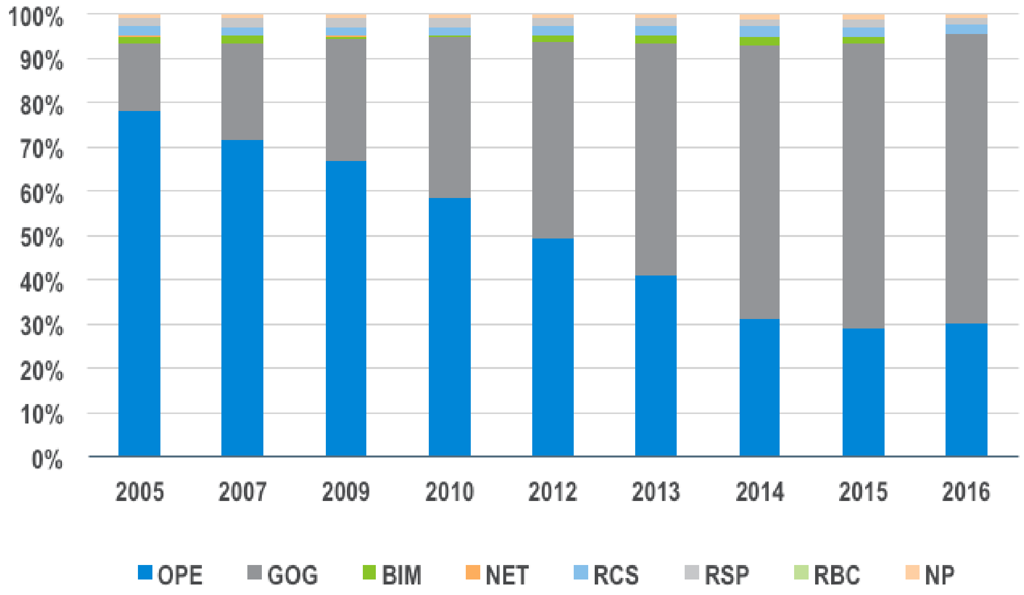
Oil-indexed prices have been associated mainly with long-term contracts while hub prices have been associated with spot or short-term contracts. Oil-indexed long-term contracts prevailed in the gas sector because they were considered to ensure investment security for the producer as well as security 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.

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. 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.

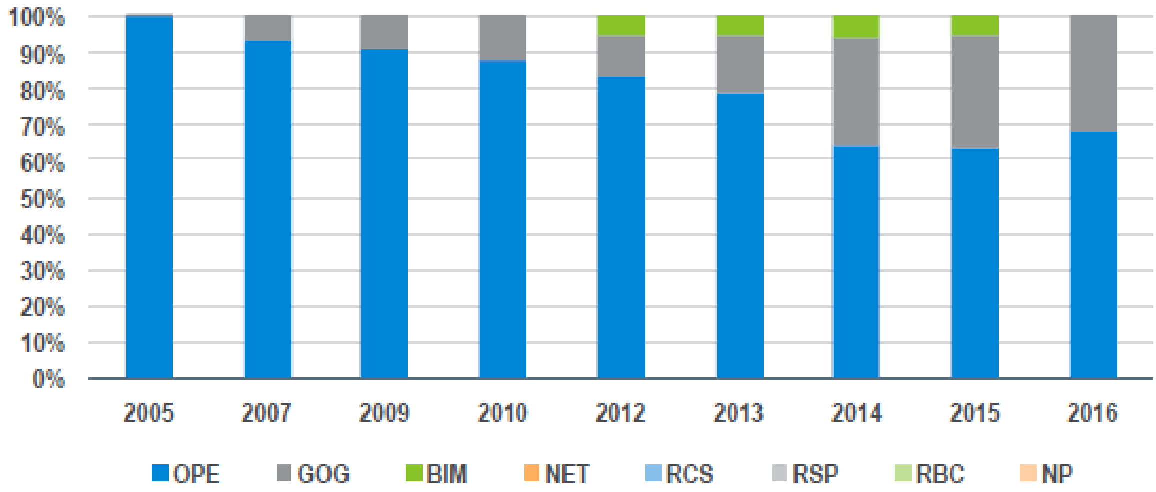
[38] Oil price escalation (OPE): The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal prices can be used as can electricity prices.

Figure 42 – Price formation in Europe



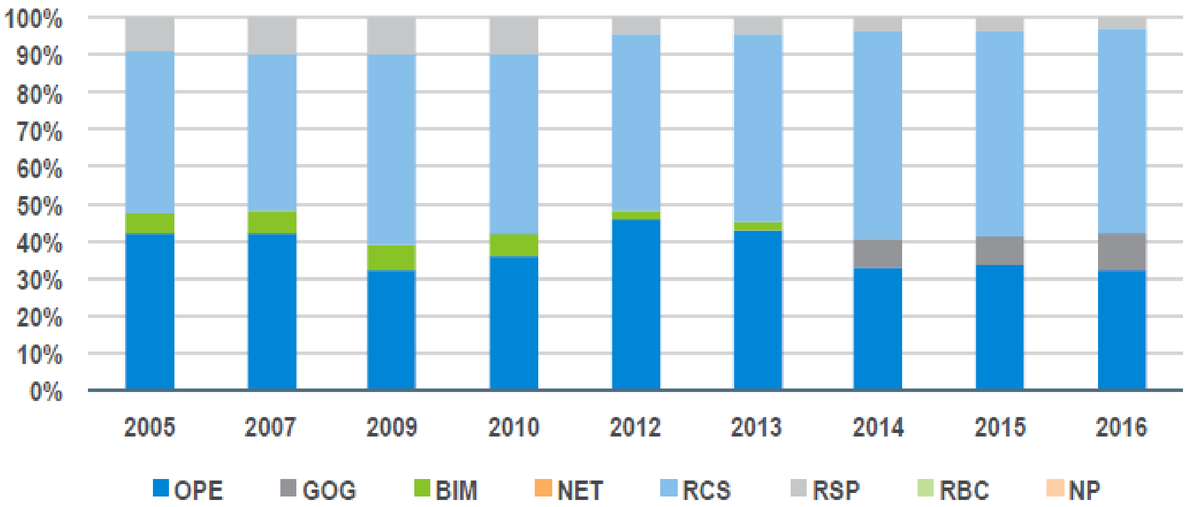
Source: IGU

Figure 43 – Price formation in the Mediterranean region



Source: IGU

Figure 44 – Price formation in South Eastern Europe



Source: IGU

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 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.

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. 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.

The Jungle of European Regasification Costs

Access to regasification capacity and regasification costs are key drivers to be considered when making decisions on where to market LNG. This section will shed light on European regasification costs based on various data collection.

Firstly, terminals exempted from regulation are not obliged to publish their tariffs. Therefore, there is a lack of transparency on regasification tariffs especially in the UK and the Netherlands. The new French terminal in Dunkerque also does not publish any tariffs as is the case for the exempted part of the Italian Rovigo terminal (Adriatic LNG).

By contrast, regulated terminals have to make their tariffs transparent to the public. However, this does not mean that each terminal operator publishes the very same tariff for the same service or in other words tariffs cannot be compared easily. The tariff landscape is multifaceted – from all-inclusive tariffs to tariffs per cargo (independent of the actual cargo size), to two component tariffs (fixed and variable) to even more complicated systems.

According to EU legislation, each member state is obliged to have an independent regulator with defined powers and duties. This is meant to the creation of a level playing field for all market participants. Tariffs for access to regasification infrastructure have to be approved by the regulator[39].

Based on data provided by Consult TEAM (24), which is headquartered in Berlin and is an internationally active and networked consultancy firm for the energy sector, the results presented are based on tariffs in Belgium, Spain, Poland, Greece, France and Portugal.

In general, two systems of tariffs can be differentiated at regulated European terminals. On the one hand, there are tariffs that consist of different components according to the LNG service chain and thereby, have individual pricing tags for berthing/ unloading, storage and regasification. Examples for the first type are Belgium, Spain and Portugal. On the other hand, it is also quite common to distinguish between a fixed capacity charge per cargo or per booked capacity and a variable commodity charge. Terminals that rather fall under the second group are the ones in France, Greece and Poland. Some terminals also distinguish between long-term and shorter-term products.

The Belgian Zeebrugge terminal is an example where the tariff is made up of different components for berthing/unloading, storage and regasification. There is no difference between long-term or short-term products in Belgium, but the terminals offer a basic service

[39] Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009, Article 39 & 41.

defined as one slot consisting of a package of entitlements to a berthing right, basic storage and basic firm send out capacity. Basic storage means that the terminal operator has to provide a capacity of 140,000 m^3 of LNG which should be made available at the start of the subscribed slot and decrease linearly over the basic storage duration. The basic storage duration equals about 10 days. The basic send out capacity is 4,200 MWh/hour. There is a fixed fee for all individual services. Additional flexible services for storage and send-out can be booked and paid on a volume basis. Fuel gas has to be provided in kind with the compensation rate amounting to 1.3%.

The French terminals were an example for a more complex tariff, which was established in 2012. However, the tariff system was simplified for the regulatory period commencing April 1, 2017. Thereby, a system of three different types of terminal services was reduced to just a basic and a spot service after a consultation of the relevant stakeholders. Furthermore, the tariff components were simplified. Today, the tariffs only consist of a fixed tariff for each berthing slot and a commodity tariff per unloaded quantity. Contrary to the methodology applied in Greece, the spot commodity tariff is lower than the one for the basic service. Therefore, additional options as special storage send-out options, dedicated storage or send-out flexibility service are reserved to basic storage users. The send-out profile of a spot cargo is determined by the operator and should correspond to the shipper's request as long as the impact on the send-outs of other shippers is below a predefined threshold, which means that spot send-outs are subordinated to the basic service users' send-out profiles.

Consult TEAM's analysis of European terminal tariffs revealed that tariffs vary strongly between European terminals. Thereby, they assessed costs for a spot cargo of a size of 135.000 m^3 in €/MWh regasified[40]. The lowest cost observed was just above 0.65 €/MWh, whereas cost seen could be also higher than 2.50 €/MWh for certain terminals in certain months and in some specific cases. In total terms, those values correspond to about €0.6 to 2.3 million[41] for a spot cargo of a size of 135,000m3 received, unloaded, stored and regasified.

Compared to the lowest Month-Ahead mid-price observed at the TTF between January 2016 and end of April 2017 of 10.65 €/MWh, this corresponds to 6% up to 23% of the hub price. However, measured to the highest Month-Ahead mid-price at the Spanish PVB hub seen in the same period, which was about 33.00 €/MWh the range is only 2% to 8% of the hub price.

[40] Except for Fos Tonkin (France) as this terminal can just receive LNG vessels up to 75.000m3.

[41] For a spot cargo of 135,000 m3 and a conversion factor of 1 m3 LNG = 6.788 MWh applied. Fuel gas costs or additional losses are not taken into account.

The regasification tariffs in Lithuania and Italy were deliberately left out of the analysis for different reasons.

The regasification service price charged at the floating Klaipeda plant in Lithuania is stated to be 0.10 €/MWh (excl. VAT)[42] and is therefore the only all-round carefree package. This tariff has a rather political background as the country seeks to diversify its gas supply away from Russian gas. Remaining operational costs of the terminal are covered by a supply security charge, which has to be paid by all Lithuanian gas consumers regardless of whether they buy from the Klaipeda LNG terminal[43]. Therefore, the Lithuanian tariff was excluded from the selection of terminal tariffs.

The tariffs charged at Italian terminals were also excluded from the range given above as the Panigaglia terminal is a quite old terminal; the OLT terminal has special features due to being a floating offshore terminal and at the Rovigo terminal 80% of the capacity is exempted from regulation. The published tariff, therefore, applies only to 20% of the capacity. Furthermore, there is a special guarantee factor for Italian terminals which shall cover 64% of the total revenue. From the published tariffs, Consult TEAM estimates the regasification costs at Italian terminals to be quite high[44], which might be the main barrier to any spot LNG imports into Italy so far[45].

According to ICIS European LNG Terminal Manual of Q117 (25), LNG regasification tariff at the OLT terminal stood at $1.05/MMBtu during the first quarter of this year, while at the Rovigo terminal reached $1.26/MMBtu, without including 0.7% fee. Table 41 illustrates the regasification tariffs in several other European LNG terminals as of Q117, while Table 42 shows the LNG tariffs in Turkey's three existing LNG terminals.

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[42] LNG regasification service price, approved by the Company based on LNG regasification service price cap set by National Commission for Energy Control and Prices on November 17, 2016 by the resolution No. O3-368.

[43] National Commission for Energy and Control Prices: AB "Amber Grid", http://www.regula.lt/en/Pages/ab-amber-grid.aspx.

[44] E.g. regulated tariff at Rovigo terminal is above 1.4 $/mmBTU.

[45] Mereghetti, M. (2016), "Italy's regasification fees still too high for LNG spot deliveries- traders", published in ICIS Heren as of February 24, 2016.

Table 41 – LNG Regasification Tariffs in Europe as of Q117

TARIFFS	REGAS	RELOAD
Spain (all terminals)	$0.40/MMBtu	$0.575/MMBtu
Swinoujscie, Poland	$0.65/MMBtu ($2.07/MWh), or around $0.30/MMBtu with 50% discount	n/a
Klaipeda LNG, Lithuania	$0.030/MMBtu (€0.10MWh)	n/a
Zeebrugge, Belgium	$0.20/MMBtu	$0.08/MMBtu
UK (all terminals)	not provided	not provided
Gate, Netherlands	not provided	not provided
Revithoussa, Greece	$0.49/MMBtu for a 75,000cbm cargo	n/a
OLT, Italy	$1.05/MMBtu	n/a
Adriatic LNG, Italy	$1.26/MMBtu not including 0.7% fee	n/a
Dunkirk, France	not provided	not provided
Fos Cavaou, France	$0.50/MMBtu (MedMax), $0.47/MMBtu (standard cargo), $0.46/MMBtu (Q-Flex), $0.45/MMBtu (Q-Max) and on spot, $0.39/MMBtu (MedMax), $0.36/ MMBtu (standard cargo), $0.35/MMBtu (Q-Flex) and $0.34/MMBtu (Q-Max)	Standard cargo reloads $0.17/MMBtu
Montoir, France	$0.29/MMBtu (MedMax), $0.27/MMBtu (standard cargo), $0.26/MMBtu (Q-Flex), $0.25/MMBtu (Q-Max) and on spot, $0.24/MMBtu (MedMax), $0.21/ MMBtu (standard cargo), $0.20/MMBtu (Q-Flex) and $0.19/MMBtu (Q-Max)	Standard cargo reloads $0.15/MMBtu
Fos Tonkin, France	$0.41/MMBtu (MedMax)	Small scale reloads (15,000cbm) $0.32/MMBtu, (7,500cbm) $0.42/MMBtu

Note: Regasification tariffs are based on a cargo of 155,000cbm unless otherwise stated. All tariffs are approximations as currency conversions will fluctuate, and in some cases tariffs will vary depending on the type of capacity held by a capacity holder, including length of contract and options. Tariffs calculated on the basis of a 155,000cbm cargo equating to 3627000MMBtu and a Euro/USD conversion of 1.06696. Costs worked out as dollar conversion rate multiplied by total euro cost per vessel divided by the number of MMBtu in a 155,000cbm vessel.

Source: ICIS LNG Edge

Table 42 – LNG Tariffs in Turkey as of Q117 (USD/MMBtu)

Marmara Ereglisi				Etki LNG	Aliaga LNG			
Regas	Reload	Storage	Total	Regas+Reload+Storage	Regas	Reload	Storage	Total
0,061758	0,011105	0,288290	0,361153	3,855663	0,061758	0,011105	0,288290	0,361153

Source: Yardim, G. (2017)[46]

In summary, the comparison of European regasification tariffs is a difficult exercise as there is a multitude of technical factors inherent to the different terminals which in turn have an impact on the terminal access conditions and basic services, respectively. Thereby, each terminal and tariff has its specialities. As different as the approaches in tarification are the final costs per MWh of regasified LNG. Overall, in general, four major factors influence the type and level of European regasification tariffs: (a) access rules, (b) age of infrastructure, (c) type of infrastructure (onshore/offshore) and (d) political aspects. The latter applies especially to terminals that were built for security of supply reasons.

Box 3: FSRU economics

Capital Expenditure (CAPEX)

CAPEX for regasification terminals typically consists of costs associated with vessel berthing, storage tanks, regasification equipment, send-out pipelines and metering of new facilities. CAPEX for floating terminals is considerably lower than onshore facilities, owing to the absence of storage tanks and a much smaller onshore footprint (if any).

The cost of floating terminals varies considerably with one operating via an offshore buoy and submarine pipeline costing considerably more than an FSRU berthed inshore against a berth. A converted LNG carrier will be considerably cheaper than a new build FSRU (but probably less efficient and lower capacity). If a breakwater is needed this can add considerably to costs. The CAPEX for the Punta de Sayago project in Uruguay includes $600 million for an offshore jetty and breakwater.

The IGU[47] advises that the weighted average unit cost of onshore regasification capacity that came online in 2015 was $245/tonne (based on a three-year moving average). New floating terminals' CAPEX have remained roughly steady over the past three years, declining from a high of $153/tonne in 2011 to a weighted average unit cost of floating regasification in 2015 of $109/tonne, based on a three-year moving average.

[46] This dataset was kindly provided by Mr. Gökhan Yardim, General Manager at Angoragaz Inc. (Turkerler Group) in Turkey.

[47] IGU World Gas LNG Report - 2016 Edition

The rise in onshore regasification costs is closely associated with the trend of increased LNG storage capacity. However, several new onshore terminals with smaller storage units are expected online in 2017, bringing down overall costs. CAPEX for onshore capacity under construction is set to fall to $172/tonne in 2017.

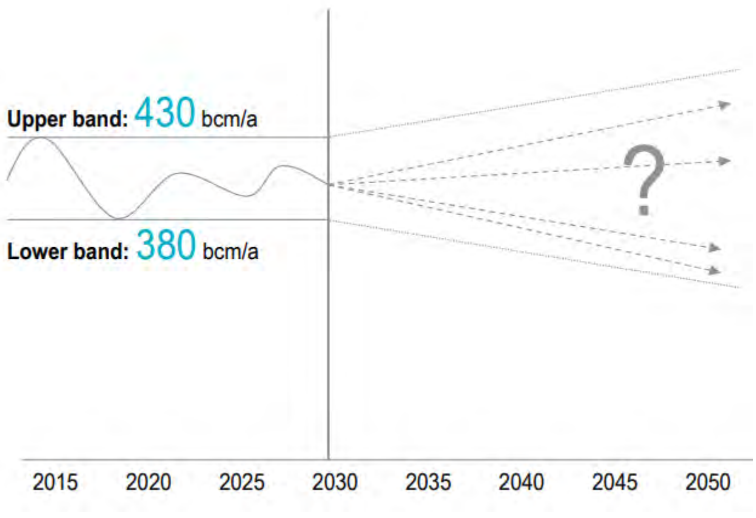
Operating Expenditure (OPEX)

Project developers usually charter in the FSRU at a daily hire rate and consider the vessel charter as OPEX instead of including it in CAPEX. OPEX for floating terminals can be higher than an onshore terminal due to greater manpower requirements – having to maintain the vessel's crew and keep the vessel seaworthy. Fewer crew are needed if the vessel is permanently moored (and propulsion systems removed).

Discussion

The European Commission expects gas demand in Europe to remain fairly stable until 2030 varying between a lower and upper band of 380 and 430 bcm/y (see Figure 45). As the EU's gas production is expected to decline significantly, gas imports need to increase in order to meet demand.

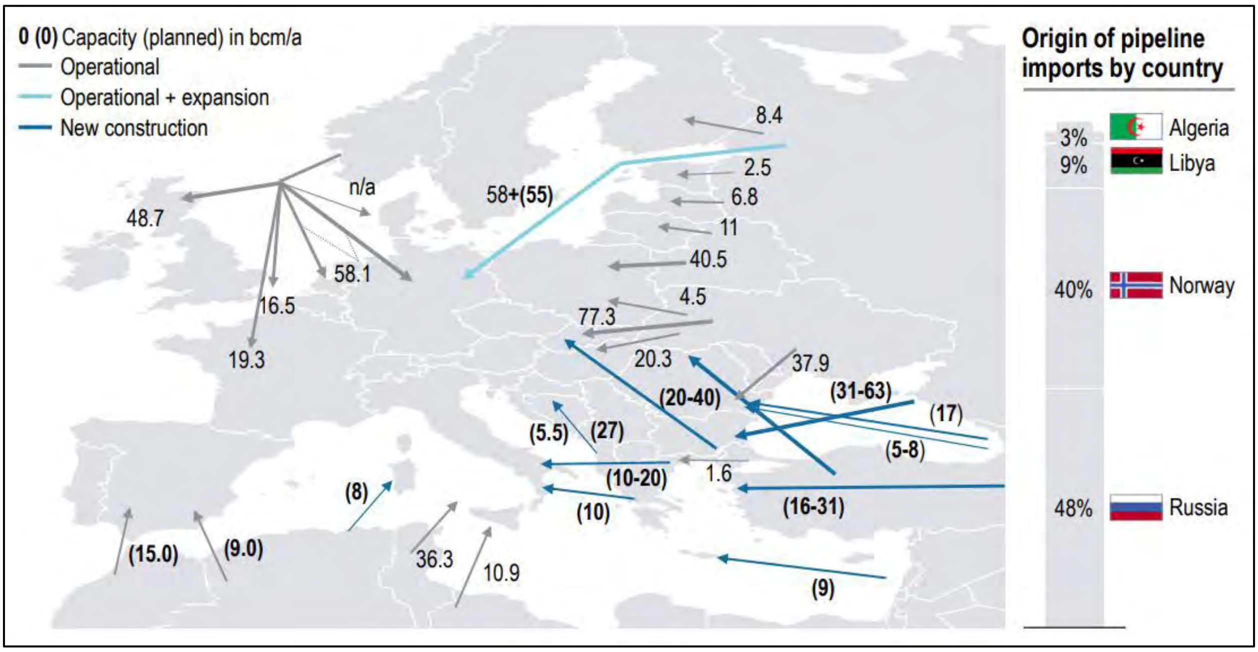
Figure 45 – Gas demand projections in Europe



Source: European Commission

Ongoing pipeline projects in SE Europe will add considerable volumes to the EU's overall import capacities. Map 40 shows the existing and planned import pipelines to Europe with planned related capacity as well as the origin of pipeline imports on a country basis with Russia holding almost the half.

Map 40 – Existing and planned import pipelines to Europe

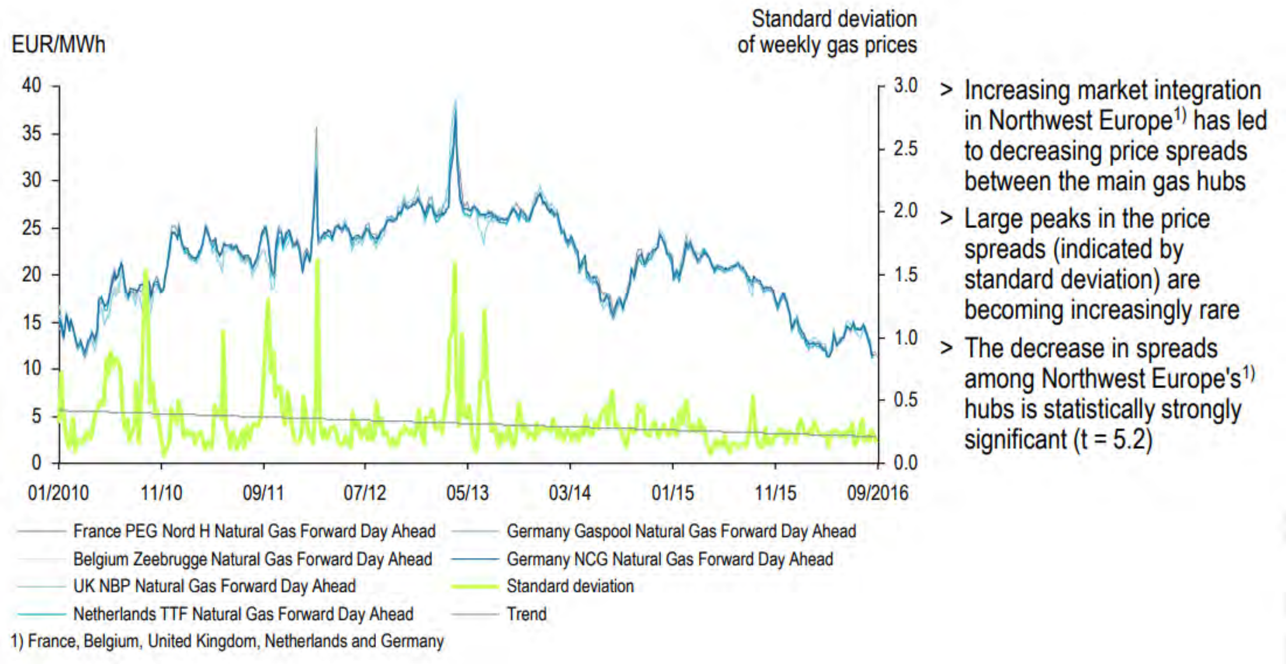


Source: European Commission

Liquidity in Europe's natural gas trading points increased steadily since markets opened in early 2000s. From 2004 to 2015, gas trading volume in Western Europe increased more than six-fold with CAGR of 18% per year, based on European Commission’s data. New interconnections and increasing gas trade bear fruit as price differences between integrated market areas have decreased (see Figure 46).

The creation of a regional gas hub could strongly benefit not only the SE European region, but also Europe as a whole. The regional benefits include gas supply diversification of former single source countries, increased security of supply, lower gas prices for household and industrial customers as well as new business opportunities and high-skill job creation. The Europe-wide benefits include enhanced security of supply through access to additional, high capacity supply streams, deeper integration of the Southern Gas Corridor into the European gas transmission system and continued liberalization of the European gas market. Both benefits provide robust economic and political justifications for the creation of the regional gas hub.

Figure 46 – Effect of market integration on prices



Source: Bloomberg

As already analysed, the regional gas hub will be located at the cross-road of SE Europe's current and future pipeline systems. The hub will enable gas trading from a wide range of alternative sources, including Russia (via onshore and offshore), Southern gas corridor, LNG terminals in Greece and Turkey and local production of Bulgaria and Romania, among others.

The ongoing and planned gas infrastructure projects represent the basis for the hub development in Alexandroupolis. The on-time completion of ongoing gas infrastructure projects is crucial for the development of the hub, including gas interconnection projects, general transmission overhauls and storage expansion. In addition, full implementation and compliance with the European Acquis is a key prerequisite for the development of the gas hub.

10. Financing of gas infrastructure projects in SE Europe

A series of factors has left the region’s performance well behind emerging markets elsewhere in the world. The legacy of wide spread foreign-currency lending, the need to rebuild balance sheets, the sluggishness of the west European market and concerns that continuing eurozone problems could yet cause contagion farther east are all compound factors that restrain growth prospects.

But “emerging” Europe’s growth, including the 13-country group, is a couple of percentage points or more behind its pre-2008 levels with only Turkey being far ahead in terms of annual GDP growth. The question remains as to what is going to propel the region forward. In the old days, it was foreign direct investment, manufacturing, construction and real estate. Now, many government economists observe that the region is becoming once more attractive to both foreign and local investors not so much on account of low cost manufacturing but primarily because of a competitive environment in services and tourism and also in the energy sector where each country is starting to offer a variety of incentives. Energy is now emerging as a business generation pole in its own right and not just as infrastructure network necessary for serving the needs of the rest of the economy.

In the coming years, the entire region will require tens of billions of euros of investments to upgrade existing gas infrastructure. But the financial crisis and subsequent need for fiscal consolidation across European states have left governments constrained in their ability to pay for these projects. Policymakers, banks and construction companies are therefore rethinking how 21st century infrastructure will be financed. European Union structural and cohesion funds – a €170bn ($240bn) pot of development money designated to help eastern European countries catch up with the richer west – will continue to be a key source of gas infrastructure financing for the region.

However, EU funds will not be enough to fill the entire gap as they are not suited for all gas projects and are unavailable to non-member states. At this field, the European Investment Bank (EIB) and the European Bank for Reconstruction and Development (EBRD) play a crucial role. Public-private partnerships (PPP), by which governments and the private sector share risk to pay for, construct and operate infrastructure, may become increasingly common as these can help minimize damage to government balance sheets. In spite of exceptions, such as Poland and Hungary, however, PPP is only now becoming widespread in Central, Eastern Europe and the Balkans. This is partly explained by the crowding out effect of “free” EU funding but experts say it also reflects a lack of institutional understanding of these complex projects in some countries, which they are now rushing to improve.

Although private partners are now required to put up more equity, banks remain willing to finance projects so long as the legislative and regulatory framework is amenable and projects are well designed. “The challenge is to find projects that are well-structured and risk has been properly allocated and to implement an infrastructure programme you need strong political commitment as well as political stability," says Massimo Pecorari, co-head of Project and Commodity Finance at UniCredit (26).

Other areas of innovation include the possibility of combining PPP with EU funds to finance gas infrastructure, a model still relatively untested regionally. Meanwhile, the European Commission in February 2015 opened the door for project companies to tap capital markets when it launched the Juncker Fund.

There is no doubt that banks and financial institutions at large extent will continue to play a leading role in the funding and promotion of the vast majority of energy related projects in the SE European region, including gas projects. A number of external financial institutions are currently involved in funding planned gas infrastructure in SE Europe. These external financiers include International Financial Institutions (IFIs) that are active in the regional gas sector, such as the aforementioned EBRD and EIB, the World Bank, the German government-owned development bank KfW, a selection of private investors and relevant Directorate General at the European Commission.

Realizing gas infrastructure projects requires funding across the entire project cycle; from initial concept to eventual maintenance of the commissioned infrastructure. Funding must be sufficient to cover a range of services, equipment and works at the different stages. The main sources of financing include:

- Government/own resources
- IFIs
- Commercial banks/private investors
- Donor funded blending facilities and technical assistant programmes

More specifically, **government financing** can be provided as one of, or a combination of, the following: (a) a direct allocation of public funds, (b) revenues from the gas services provided by the state company involved, (c) the provision of state guarantees for loans assumed by state companies for specific gas investments, (d) financing of incentives (e.g. grants to cover Research & Development (R&D) costs) to encourage private sector investors.

The main **International Financial Institutions (IFIs)** active in SEE region are the EBRD, EIB, KfW and the World Bank. All have financed a substantial portfolio of energy related investments and are actively exploring new opportunities. The IFIs participate in projects on an individual and on a joint basis. The tendency to cooperate has been strengthened by the participation of all the IFIs in the EU-led Western Balkan Investment Framework (WBIF) and the participation of the European IFIs in the Neighbourhood Investment Facility (NIF). These EU-led facilities provide EU grant funding to complement loan financing of infrastructure projects in the Western Balkans and Eastern Partnership countries respectively.

Commercial financiers (banks and investors) are active in the gas sector in many SE European countries, but are not heavily involved in the financing of large-scale infrastructure. Many of the commercial banks active in the region are subsidiaries of European banks and they have reduced their overall exposure in the region following the financial crisis. The majority of these facilities are supported by credit lines from IFIs such as EBRD, EIB and KfW, and in some cases technical assistance is given to the banks, to promote and manage these products that are new to the region.

A number of grant-funded instruments are available to support the development of socioeconomic infrastructure including gas infrastructure. These can be divided into two categories: **(a) EU-led blending mechanisms** and **(b) Technical Assistant (TA) programmes.** The main aim of blending mechanisms is to leverage external cooperation funds by mobilizing loans from financial institutions. Blending aims to address sub-optimal investment situations in the case of activities or gas infrastructure that could be viable but do not attract sufficient funding from market sources.

They provide a platform for the European Commission, IFIs and bilateral donors to work closely together and to undertake large projects, which would have been difficult to finance otherwise. Two relevant mechanisms are the Western Balkans Investment Framework (WBIF) and the Neighbourhood Investment Facility (NIF). In general, TA programmes are funded by the EU and bilateral donors and provide expertise and capacity building services to the public administrations. The assignments are usually linked to improving the overall policy climate, regulatory reform and public administration reform.

Country Risk in SE Europe

The country risk factor is an important parameter which must be taken seriously into account when taking an (energy) investment decision. The country risk is a collection of risks associated with investing in a foreign country. These risks include a combination of political and economic risks, exchange rate risk, sovereign risk and transfer risk, which is the risk of capital being locked up or frozen by government action. Some countries have high enough risk to discourage much foreign investment. Table 43 presents how different the Country Risk is among the 13 SEE countries, while Table 44 defines the ratings used in Table 43.

Table 43 – Country Risk in SE Europe

Country	Moody's ratings	S&P ratings	Fitch ratings
Albania	B1 (August 2017)	B+ (February 2016)	n.a.
Bosnia and Herzegovina	B3 (February 2016)	B (March 2012)	n.a.
Bulgaria	Baa2 (May 2017)	BB+ (June 2017)	BBB- (June 2017)
Croatia	Ba2 (March 2017)	BB (September 2017)	BB (July 2017)
Cyprus	Ba3 (July 2017)	BB+ (September 2017)	BB (October 2017)
FYROM	n.a.	BB- (May 2013)	BB (August 2017)
Greece	Caa2 (June 2017)	B- (July 2017)	B- (August 2017)
Montenegro	B1 (September 2017)	B+ (October 2017)	n.a.
Romania	Baa3 (April 2017)	BBB- (May 2014)	BBB- (July 2017)
Serbia	n.a.	BB- (December 2016)	BB- (June 2017)
Slovenia	Baa1 (September 2017)	A+ (June 2017)	A- (August 2017)
Turkey	Ba1 (March 2017)	BB (January 2017)	BB+ (July 2017)

***Source: Country Economy*[48]**

Slovenia, Bulgaria and Romania have lower Country Risk than the rest of the SE European countries, while Greece has the highest.

[48] "Sovereign Ratings List", http://countryeconomy.com/ratings

Table 44 – Classification of Moody's, S&P and Fitch ratings

Grade	Moody's	S&P	Fitch
Prime	Aaa	AAA	AAA
High grade	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
Upper medium grade	A1	A+	A+
	A2	A	A
	A3	A-	A-
Lower medium grade	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-
Non-investment grade speculative	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
Highly speculative	B1	B+	B+
	B2	B	B
	B3	B-	B-
Substantial risks	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
Extremely speculative	Ca	CC	CC
			C
In default with little prospect for recovery		SD	RD
In default	C	D	D
			DD
			DDD
Not rated	WR	NR	

Grade	Moodys	S&P	Fitch
High grade	P-1	A-1+	F1+
Upper medium grade	P-1	A-1	F1
Lower medium grade	P-2	A-2	F2
Non-investment grade speculative	P-3	A-3	F3
Highly speculative		B	B
Extremely speculative	NP	C	C

Source: Country Economy

11. Conclusions

According to IEA's Gas Market Report 2017, gas will grow faster than oil and coal over the next five years, helped by low prices, ample supply, and its role in reducing air pollution and other emissions. In its new five-year forecast to 2022, gas demand will grow at 1.6% per year, a slight upward revision from last year's forecast of 1.5%. This means that annual gas consumption almost reaches 4,000 bcm by 2022, from around 3,630 bcm in 2016. Almost 90% of the anticipated growth in demand comes from developing economies, led by China.

Resource-rich parts of the Middle East and Africa also see strong demand for locally-produced gas. The Middle East will experience relatively strong growth in consumption of 2.4% per year, to around 540 bcm, met in the main by increasing domestic production. Growth is relatively strong in the power sector, where there are opportunities to substitute gas for oil, as well as in the industry sector as the region's economies grow and diversify. Consumption in Africa rises even more quickly, at 3.1% per year, to reach more than 150 bcm. Egypt, Algeria and Nigeria are the main countries pushing consumption higher, even though lower hydrocarbon revenues and economic growth hold back demand in some resource-rich parts of the continent. Elsewhere, annual gas demand growth in Latin America averages 1.3%, while the consumption outlook remains flat in Russia, Eastern Europe and Central Asia.

European gas demand rose in 2016, thanks to low gas prices and coal plant retirements, but is forecast to stay flat out to 2022. After four years of decline from 2010, European gas demand increased for the second year in a row in 2016. Lower gas prices, higher coal prices, coal plant retirements and nuclear outages in France have pushed up gas demand for power generation. Over the forecast period, demand will remain flat, as growth will be constrained in the power sector by limited electricity demand growth and the continued rise of renewables, and in industry by sluggish growth in European industrial output.

The United States, the world's largest gas producer, will increase production more than any other country over the next five years, accounting for almost 40% of global output growth. While overall US production fell in 2016, output from the Marcellus basin continued to grow, underscoring the ability of US gas drillers to counter the effect of lower prices by improving efficiency and producing more gas with fewer rigs. The continuing development of the Marcellus and Utica shales is being supported by the extension of pipeline infrastructure from the Appalachian region to ship more gas to markets in the Northeast, Midwest, and Southeast regions of the United States and in Eastern Canada. Over the forecast period, US gas output is expected to grow by 2.9% per year, adding around 140 bcm to global production. By 2022, the United States will produce approximately 890 bcm, or 22% of the total gas produced worldwide. Although US domestic demand for gas is growing due to increased demand in industry, more than half of the production increase will be turned into LNG for export. By the end of our forecast period, the United States will be well on course to challenging Australia and Qatar for global leadership among LNG exporters.

According to IGU's 2017 World LNG Report (27), gas accounts for roughly a quarter of global energy demand, of which 9.8% is supplied as LNG. Although LNG supply previously grew faster than any other gas supply source – averaging 6.2% per annum from 2000 to 2015 – its market share growth has stalled since 2010 as indigenous production and pipeline supply have competed well for growing global gas markets. Despite the lack of market share growth in recent years, the large additions of LNG supply through 2020 mean LNG is poised to resume its expansion.

In SE Europe, LNG seems to be a realistic fuel alternative in view of the need to differentiate the region's supply sources and supply routes, part of an overall effort to improve security of energy supply. Furthermore, increased LNG use will provide the opportunity for US gas to be traded in the region, while it enhances pricing flexibility and safer gas transportation. In addition, secure LNG volumes can help support underperforming gas pipeline projects. Thus, the important role that the Alexandroupolis FSRU project can play in SE Europe is evident, especially if we take into account the anticipated increased gas liquidity in Northern Greece, the existing Interconnector Turkey-Greece, the under-construction TAP, the soon to be constructed Interconnector Greece-Bulgaria and Interconnector Greece-Italy, as well as the planned underground gas storage in South Kavala.

It is fair to state that increased LNG volumes, to be supplied to the region via alternative terminals, will help avert a deterioration of security of gas supply conditions in SE Europe, which would become inevitable if we were to rely on the existing and rather conventional gas framework. Furthermore, the emergence of gas-to-gas competition in the region is to be facilitated by strategically positioned gas sources such as the Alexandroupolis FSRU.

Finally, the organized development of a regional gas trading hub would be a positive outcome for the rest of Europe as it would facilitate flexibility, efficiency and price competition. Gas hub development is an on-going practice in Europe. New gas hub enterprises need to be established in innovative ways to gain a competitive position in the market. There is little LNG-to-rail unloading at existing European LNG receiving terminals.

New SEE hubs are all envisaged with access to railway and ISO container loading on a large scale. The capacity to load LNG to trucks in Europe is very limited, accounting for only 0.1-0.2% of total gas demand, based on data provided by the Oxford Institute for Energy Studies. Nearly one third of gas to SEE may be delivered to customers by containers and intermodal transport. The European marketplace is intended for large integrated players. The SEE emerging gas market provides opportunities for small- and mid-scale innovative players. Flexibility in Europe is to a large extent based on conventional upstream solutions while SEE provides an opportunity for renewable energy combined with gas and power flexibility mechanisms. Flexibility requires low cost infrastructure options capable of sustaining variable utilization rates: floating gas supply options are likely to have a competitive advantage.

12. Key messages

- **The global gas market continues to evolve rapidly.** The shale revolution shows no sign of running out of steam, and its effects are now being amplified by a second revolution, caused this time by rising supplies of LNG. The US is in the frontline of both of these revolutions, and the disruption to traditional gas business and pricing models will continue to have profound impact on gas markets over the next five to ten years.
- **New liquefaction capacity**, mostly from the US and Australia, **is coming online at a time when the LNG market is already well supplied. This LNG glut is already affecting price formation and contracts, and attracting new customers.** The list of LNG-consuming countries has expanded to 39 this year from just 15 as recently as 2005, with the newcomers including Pakistan, Thailand, Jordan, Israel and Malta. The list of LNG importers is expected to grow longer in the next five years as many countries are ready to benefit from today's low LNG prices.
- **Global gas demand continues to increase at a steady clip, but, over the next decade, the power sector will no longer be the main source of growth worldwide.** Instead, it will be industrial consumers that will take up much of the slack in the market, with China, the rest of developing Asia, the Middle East and the US leading the way. The power sector remains the largest consumer of gas, but growth opportunities are being squeezed by the deployment of newer, more efficient gas-fired power plants, the continued expansion of renewable generation and competition from cheap coal.
- 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 and possibly from the Middle East (i.e. Iraq, Qatar) and Iran. Consequently, **after 2019-2020, 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 in a more transparent way.**
- **Europe currently has a huge excess of LNG import capacity. However, the excess capacity is unevenly distributed between Western and SE Europe and Central Europe.** Consequently, EU's much touted "brave new" LNG strategy, when finalized, will have to take into consideration the excess LNG storage and regasification capacity and its geographical spread.

- It is anticipated that the SE European region will play a significant role in expanding LNG trade in Europe by 2020 through the construction and operation of several new LNG regasification projects such as **the FSRU unit that is planned to be located offshore in Alexandroupolis, in Northern Greece, with the prospect of feeding gas quantities into the Greek, Bulgarian, Serbian and Turkish gas systems, among others.**
- **The selection of Alexandroupolis is not random** but takes into consideration the increased gas liquidity in Northern Greece with the existing Interconnector Turkey-Greece, the under construction TAP as well as the planned Interconnectors Greece-Bulgaria and Greece-FYROM, Interconnector Greece-Italy and the potential underground gas storage facility in South Kavala. Thus, the project can be characterized as a new gas gateway to Europe.
- **The Alexandroupolis FSRU project will be the only new gas infrastructure project in SE Europe which will not rely on Turkey** as a transit country (TANAP/TAP system, Turkish Stream, new quantities from Iran, Caspian, etc.).
- **Greece and Turkey are the only countries in the broader Black Sea-SE European region which at present possess LNG gasification terminals** which are well linked and integrated into their national gas systems.
- Given the combined gas demand in both countries, the gas systems of which are linked with the Greece-Turkey interconnector in Thrace since 2007, it becomes obvious that the combined gas demand is amply served by the storage capacity and rate of gasification of the existing land based and new FSRU installations. As a result, **the spare capacity of these terminals (i.e. Revithoussa, Aliaga LNG, Marmara Ereglisi and ETKI LNG) has on many occasions been used for transshipment purposes, which shows the dual role that LNG gasification terminals can play in the region**.
- **Five other LNG gasification projects in SE Europe are at an advanced stage of implementation**, including the Plinacro plant on Krk island off Omisalj, the Alexandroupolis FSRU project in northern Greece and three others in Turkey; in Aliaga, in the Gulf of Saros and in Dörtyol, a district in the southern province of Hatay, in southern Turkey. **That brings the total number of planned LNG projects in the area up to nine.** Even if half of these projects actually get built, the region's LNG capacity will have expanded immensely, helping change market dynamics in the

Adriatic-Aegean axis. Such development will undoubtedly enhance regional gas trade and refocus Mediterranean gas trade movements.

- It appears that **LNG prospects in SE Europe and the East Mediterranean** in particular, **are far better placed than they were five years ago** with new projects getting ready to evolve and **LNG returning as a fuel of choice for several industrial consumer groups and electricity companies helped by lower prices and increased availability**.
- **Natural gas is a new source of energy for SEE countries, some of which lack even the basic gas infrastructure**, including Albania, Kosovo and Montenegro. With few exceptions, such as Albania, Romania and Croatia, **the region is generally poor in terms of oil and gas resources.** Some of the region's countries (i.e. Bulgaria, FYROM and Bosnia and Herzegovina) are almost 100% dependent on oil and gas imports. Moreover, most of those countries are dependent on a sole supplier, namely Russia, which has a dominant position and therefore presents challenges in terms of energy security. Given their dependence on a single supplier, there appears to be no competition in these markets. As a result, they buy gas at the highest prices in Europe. In this sense, Serbia, Kosovo and FYROM are landlocked. Thus, they do not have the LNG option as a means of ensuring gas supply diversification as they can only purchase gas via pipelines. This situation is likely to change with the appearance of new LNG facilities such as Krk LNG Terminal and Alexandroupolis FSRU.
- **Geopolitical factors play an important role in gas infrastructure projects in the SE European region.** Some of the key suppliers' objectives are easier to identify: **(a)** Russia wants to maintain its dominant position as supplier while diminishing reliance on Ukrainian transit, **(b)** the European Commission, backed by the US, wants to differentiate EU imports away from Russia, as Washington wants to preserve its influence in Europe and stave off geopolitical competitors. The position of other actors is less defined. With support from their respective governments, Greek, Italian and Turkish companies are involved in both the EU- and Russia-driven projects. By doing so, they seek to maximise profits, pursue national energy security goals and strengthen their strategic position in international energy politics.
- **The geopolitical importance of the Alexandroupolis FSRU project has grown as a result of the Ukraine crisis, the abandonment of the South Stream pipeline and Russia's decision to discontinue transit flows through Ukraine as of 2019**, which has raised the level of concern within the EU with regard to the energy security and

the uninterrupted gas supply of European markets, especially of those which lack alternative supply sources and routes, such as the countries of SE Europe.

- Existing gas hubs, which currently operate in Europe, meet more than 50% of gas trading while the creation of new gas hubs is being considered. New gas hub enterprises need to be established in innovative ways in order to gain a competitive position in the market. **Thus, the development of a regional gas trading hub in SE Europe would be a positive outcome for the rest of Europe as it would facilitate flexibility, efficiency and transparency.**
- **The implementation of regional gas infrastructure projects can be achieved by recourse to various sources of financing** (i.e. government/own resources, international financial institutions, commercial banks/private investors, donor funded blending facilities and technical assistant programmes). However, an important parameter that needs to be considered is the **country risk factor**, which is a collection of risks associated with investing in a foreign country. These risks include a combination of political and economic risks, exchange rate risk, sovereign risk and transfer risk, which is the risk of capital being locked up or frozen by government action. Some countries have high enough risk to discourage much foreign investment.
- In view of the above, IENE's analysis shows that there are **no significant technical and non-technical obstacles** in pursuing the implementation of current plans for the expansion of major gas infrastructure projects, at national and regional level with projects, such as the Alexandroupolis FSRU, demonstrating financial and technical viability together with flexibility in terms of location and operation.

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Appendix

Table of Regasification Terminals in the Mediterranean Sea

Country	Terminal Name	Start Year	Nameplate Capacity (mtpa)	Owners	Concept
Spain	Barcelona	1969	12.8	ENAGAS 100%	Onshore
	Huelva	1988	8.9	ENAGAS 100%	Onshore
	Cartagena	1989	7.6	ENAGAS 100%	Onshore
	Bilbao	2003	5.1	ENAGAS 70%; EVE 30%	Onshore
	Saggas (Sagunto)	2006	6.7	ENAGAS 72.5%; Osaka Gas 20%; Oman Oil 7.	Onshore
	Mugardos LNG (El Ferrol)	2007	2.6	Grupo Tojeiro 50.36%; Gobierno de Galicia 24.64%; First State Regasificadora 15%; Sonatrach 10%	Onshore
	El Musel	2013	5.4	ENAGAS 100%	Offshore
Greece	Revithoussa	2000	3.3	DEPA 100%	Onshore
Italy	Panigaglia (La Spezia)	1971	2.5	GNL Italia 100%	Onshore
	Italy Adriatic LNG/ Rovigo	2009	5.8	ExxonMobil 46.35%; Qatar Petroleum 46.35%; Edison 7.3%	Offshore
	Livorno/LNG Toscana	2013	2.7	EON 46.79%; IREN 46.79%; OLT Energy 3.73%; Golar 2.69%	Floating
Turkey	Marmara Ereglisi	1994	5.9	Botas 100%	Onshore
	Aliaga LNG	2006	4.4	Egegaz 100%	Onshore
	Etki LNG	2017	5.3	Etki Liman Isletmeleri Dolgalgaz Ithalat ve Ticaret 100%	Floating
Israel	Hadera Gateway	2013	3.0	Israel Natural Gas Lines 100%	Floating
Egypt	Ain Sokhna Hoegh	2015	4.2	EGAS 100%	Floating
	Ain Sokhna BW	2015	5.7	EGAS 100%	Floating

Source: IGU (2017)

Table of Liquefaction Terminals in the Mediterranean Sea

Country	Terminal Name	Start Year	Nameplate Capacity (mtpa)	Owners	Liquefaction Technology
Egypt	Damietta LNG T1	2005	5	Gas Natural Fenosa, Eni, EGPC, EGAS	APC C3 MR/ Split MR™
	Idku T1	2005	3.6	Shell, PETRONAS, EGAS, EGPC, ENGIE	ConocoPhillips Optimized Cascade®
	Idku T2	2005	3.6	Shell, PETRONAS, EGAS, EGPC	ConocoPhillips Optimized Cascade®

Note: Damietta LNG in Egypt has not operated since the end of 2012; operations at Idku in Egypt returned in 2016 after the plant did not export cargoes in 2015.

Source: IGU (2017)