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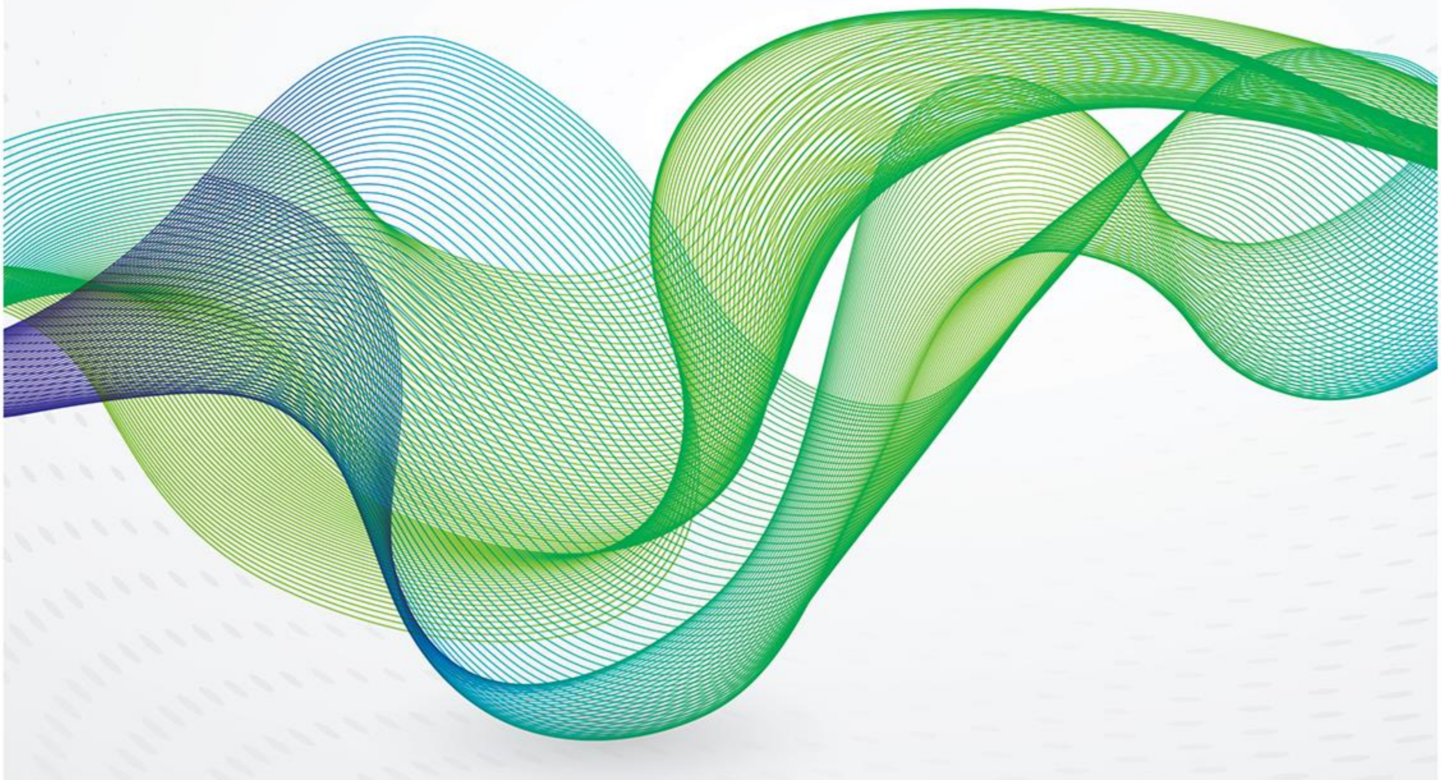
SE Europe gas markets: towards integration



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Preface

From a pure gas market perspective SE Europe appears to be peripheral. The region's total demand is around 25 bcma. Its 5 EU members account for most of this, which equates to just 5% of total EU gas demand. While there is some growth expected and there is the prospect of market creation in some of the smaller countries of the region, volumes involved will be modest.

But this point overlooks its far wider role in the European gas market both today and in the future, and the primary purpose of this paper is to explore these aspects. Firstly, it has long been a transit region for Russian gas. Russian gas enters the region from Ukraine and then mainly passes through the Trans Balkan Pipeline system through Romania to Bulgaria, Greece, Turkey and the Republic of N Macedonia. Small volumes also come via Hungary to Serbia and Bosnia Herzegovina. Most of this will change once Turk Stream (TS) is commissioned. The region, therefore, is very much part of the Ukraine transit requirement story. TS Line 1, dedicated to Turkey volumes, is likely to be on-stream around the end of 2019, which will immediately remove some 13 bcm away from Ukraine transit. TS Line 2 won't be fully loaded until a new line is built through Bulgaria and Serbia, and this leads us into interesting regulatory issues and EU gas pipeline policy with regard to Russia. Added to this, there is new transit gas about to start. From 4Q 2020 TAP will be bringing Shah Deniz 2 to Greece and Italy, and also Bulgaria.

A second key issue is the lack of regional market interconnectivity. Apart from Romania, which has been producing gas for over one hundred years, gas in the rest of the region has developed on the back of imports, most of which have been Russian. The result of pipeline configuration built to do this has basically been the creation of island markets with no connectivity between them. Numerous interconnector projects have been promoted over the last 10-15 years, but very few built. The EU well recognises the importance of interconnectivity in its general goal of an energy union and creating functioning liquid markets. Its CESEC initiative since 2015 has focused on building a short-list of priority projects, but to-date none of these have been completed. This raises an additional issue concerning the effectiveness of policy making.

Thirdly, there is the prospect of both upstream and downstream developments in the region. The Black Sea is under-explored, and if discoveries located in the Romania offshore region can start-up then the country has within its grasp the ability to become a small exporter by the mid-2020s. This would encourage regional interconnectivity as surpluses would need to be moved, and the addition of another supply line would also support market liquidity. There is also on-going exploration activity offshore Bulgaria. Downstream, EU development programmes have for long promoted the gasifiction of the Western Balkans. However, once supply has finally arrived, perhaps from TAP, there remains the challenge of creating a market creation from a zero or near zero base.

Outgoing EU Energy & Climate Commissioner Canete has said he expects all the EU's gas markets to be well connected and resilient to supply shocks by 2025. For SE Europe this is possible, but there remains a lot of basic infrastructure and market building to be done. This paper provides the context for analysing progress towards such a goal.

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Contents

Figures

Tables

Maps

I. Introduction

In many respects SE Europe seems on the periphery of both the overall European economy and of European gas. Taking the 5 EU members of the region[1] (which account for the bulk of the SE European regional economy and gas industry anyhow), these account for just 5% of the EU's aggregate GDP, 9% of its population and just 5% of its gas demand. Average GDP per capita of these 5 is 60% that of the EU-28 average, and, much in line with this, 70% of its per capita electricity consumption. Aspiring EU members of the Energy Community located in SE Europe are all below these levels.[2]

Map 1: South East Europe geography

Source: OIES
Note: Gas demand 2016 (bcm): Romania 11.5, Bulgaria 3.2, Greece 3.8, Croatia 2.6, Slovenia 0.9, Serbia 0.5, Montenegro 0, Rep of North Macedonia 0.2, Bosnia & Herzegovina 0.2, Kosovo 0, Albania 0.

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[1] Romania, Bulgaria, Greece, Croatia, Slovenia.
[2] Energy Community members included here are Serbia, Montenegro, Rep of North Macedonia, Bosnia & Herzegovina, Kosovo, Albania. SE Europe here is defined as the EU-5 & all these 6 Energy Community countries.

It is a legitimate challenge, therefore, to ask in a gas context why SE Europe should be included as having a role in mainstream European gas analysis. To respond, there are several powerful reasons which, in combination, suggest that it has to be. These include:

- **Energy Union** All countries in the region are either in the EU, or in the Energy Community. They therefore have to adopt EU gas market rules and market building ambitions. They are part of the Energy Union club, and deserve for that reason alone to be included. The small size of all the markets (except for Romania) is not itself a disqualification from inclusion in a European gas analysis.
- **Transit** Parts of the region have for around 40 years been receiving Russian gas and for over 30 years it has been a corridor for Russian gas to Turkey. To date, the only interconnectivity (with minor exceptions) between markets has been for transit of Russian gas within and through the region. But building interconnectivity between individual countries is now firmly on the Brussels and national agendas. Also, the transit role is being reshaped. If Russian's policy of no Ukraine transit is to be eventually successful, that will mean a large evacuation system will need to be built for Turk Stream Line 2 gas through parts of this region. Simultaneously, the existing major Trans-Balkan transit pipeline system will then become emptied of Russian gas and potentially redundant. Meanwhile, the southern gas corridor is starting up, and new LNG terminals are being created or planned. With demand growth probably modest, the region's traditional transit role will remain and even be enhanced, but gas flow directions will be different.
- **Black Sea offshore** If projects are sanctioned, Romania should become a small exporter in the early 2020s. Again, with only small demand growth likely, this will become another force behind the reconfiguration of gas flows, and another component for achieving further supply security and diversity.
- **Policy delivery** The region is a focus of Brussels policy action for market building and supply security (for example the European Commission's Central Europe and Southern Europe Gas Connectivity (CESEC) initiative). Assuming interconnector plans are realised, the geographic boundary of SE Europe becomes fuzzier; it will become linked with neighbouring regions, and policy becomes successful when the whole of Southern and Central Europe becomes more like NW Europe. Further, there is market building from scratch to be done in the smaller former-Yugoslav Republics and Albania.
- **EU-Russia** The relationship is complex and often antagonistic, but ultimately both sides share a linked interest in security of supply and security of market. Traditionally, Russia has had a very high market share in this region. Now, parts of the recent DG Comp – Gazprom settlement relate to Gazprom's market behaviours in SE Europe, and its dominant position could weaken.
- **Environmental - lignite** A lot of low quality coal is produced and consumed in the region's energy mix. Addressing this as part of any national or EU climate and decarbonising agenda will require very significant economic and political resources and commitment.
- **Wider European gas issues** There are two main issues here. First, because of Turk Stream, SE Europe becomes part of the equation of how fast Russia can diminish its requirement for Ukraine transit. Secondly, is there market space here for Southern Corridor gas or other new potential supply sources such as Eastern Mediterranean or Black Sea gas, as well as LNG.

SE Europe may well be on the periphery of the European gas market, but it certainly is not in terms of transit flows, investment needs and the EU-Russia gas relationship. As gas markets become increasingly regionalised and integrated, the intent in this paper is to emphasise the regional picture; the downside is the inevitable cost of sometimes skating over important individual national concerns and issues.

However, the SE European market is far from being homogenous. Countries within it range from one large market with one of the longest gas histories in the world (Romania) to several very small countries with no or only a very small gas market (for instance Albania). Further, it is very poorly interconnected by a flexible pipeline network. In many ways it looks similar to that one other region which was identified as vulnerable to low security of supply in the policy reflections after the 2009 Russia-Ukraine supply crisis – Northern Europe. There, Poland is the one dominant market, the three Baltics the satellite small markets, the main market building problem the lack of supply diversity and a complete lack of regional interconnectivity. Since 2010, however, that region has made successful efforts to address these shortcomings and other market creation issues, while by contrast, SE Europe has achieved relatively little.

II. Economic and energy context

The region is entirely in the EU or the Energy Community. The latter is highly relevant because membership is by Treaty, meaning its members (the Contracting Parties) are bound to adopt EU energy legislation and regulatory obligations. Beyond these common legal forces for gas cohesion, the purpose of this section is to put gas into an overall economic and energy context. Economic performance, and institutional capacity to create and deliver policy are clearly important drivers of the outlook for gas.

The table below gives a snapshot illustrating main macro-economic and basic energy indicators in 2016 (the most recent year for which there is a complete set of common data).[3]

Table 1: SE Europe – macro-economic & energy snapshot 2016

		SE Europe - macro-economic & energy snapshot 2016							
		Population (millions)	GDP per cap $ year 2010, ppp	Electricity demand per capita (kwh)	Gas % in total energy	Gas demand (bcm)	Gas output (bcm)	Imports from Russia (bcm)	% supply from Russia
	Romania	19.7	$20,800	2700	28%	11.5	9.9	1.7	15%
	Bulgaria	7.1	$17,400	5000	15%	3.2	0.1	3.1	97%
EU	Greece	10.8	$23,800	5500	15%	3.8	0	2.7	70%
	Croatia	4.2	$20,600	4000	26%	2.6	1.6	0.8	31%
	Slovenia	2.1	$28,900	7000	10%	0.9	0	0.5	57%
	Total / average	**43.9**	**$21,300**	**4100**		**22.0**	**11.6**	**8.8**	**40%**
	Albania	2.9	$11,000	2200	1%	0			
Energy	Serbia	7.1	$13,100	4600	12%	2.4	0.5	1.9	79%
Community	Montenegro	0.6	$15,400	4700		0			
	Kosovo	1.8	$9,100	2400		0			
	Rep of North Macedonia	2.1	$13,000	3200	7%	0.2		0.2	100%
	Bosnia & Herzegovina	3.5	$10,800	4600	3%	0.2		0.2	100%
	Total / average	**18.0**	**$12,000**	**3900**		**2.8**	**0.5**	**2.3**	**82%**
	Total SE Europe	**61.8**				**24.8**	**12.1**	**11.1**	**45%**
	Total EU-28	511.3	$35,500	6000	23%	449.3	124.7	142.9	32%
	Total SEE 5 in EU as % of EU-28	9%	60%	68%		5%	9%	6%	

Source: IEA; TSO Ten-Year Network Development Plans (TYNDPs)

[3] Table compiled from the following sources. Economic and electricity data from the IEA's World Energy. Balances. Gas demand and production is taken from the national TSOs' Ten-Year Network Development Plans (TYNDPs) which usually include historical gas supply and demand data. Where not given in the TYNDPs, imports from Russia are from Gazprom's annual factbook *Gazprom in Figures*, available on the Gazprom website. Overall EU gas supply / demand is from BP Statistical Review of World Energy.

Economy

Wealth levels relative to the EU average are low, and are also very uneven within the region. Most of the economic capacity lies within the EU-5, which account for just over 80% of the region's GDP. On a per capita basis, they are substantially wealthier than the Energy Community members ($21k vs $12k on average), although they are just 60% of the average level of EU-28 per capita GDP. Given that all the region apart from Greece was affected by the USSR or Yugoslavia dissolutions, all countries went through a period of economic dislocation and transition. Over 2000-2005 recovery was strong and regional growth averaged 5%/year. Then came the recession of 2007-9, momentum was lost, and since 2010 growth has been very low, averaging just 0.6%/year over 2010-16.

There are three main problems behind the numbers. First, population in nearly all countries has been declining: in a few, such as Romania, the decline has been quite marked. In total, in 1990 population was almost 69 million; today it is 62 million, a decline of 0.4%/year. This means that on a per capita basis, economic growth has been slightly better in recent years – 1.1%/year vs the 0.6%/year for 2010-16 above.

Secondly, one weakness with regional averages is the presence of one large entity. In this instance it is Romania, and there is a risk that Romania can distort the regional generalisations and characteristics. Romania alone accounts for approximately one-third of the region's population, one-third of its GDP and just under one-third of its total energy demand. But in energy demand the weight of Romania is very evident. With efficiency gains and the closure of a lot of inefficient subsidised industry, the region's total energy demand fell over 1%/year over 1990-2016, or by some 41 million tonnes oil equivalent. Of this 41 Mtoe drop, Romania accounts for 75%.

Thirdly, there is Greece. While it accounts for 20% of the regional economy, the depth of its 2010-15 debt crisis was sufficient to drag the whole region down.

Within the space of this paper, it is not the ambition to consider the particular characteristics or outlooks of each of the economies. Again, the emphasis here is on the region, as gas is becoming a regional energy with regional problems and regional solutions. However, a few specific points are worth making.

- The region's economic performance has been pulled down by Greece. The severe recession in Greece means that its economy has only now just about recovered to its 2000 level. Removing Greece, the region's performance over 2010-16 was substantially better at 2.7%/year rather than 0.6%/year, and double the rate of the EU-28's 1.3%/year. Greece GDP in 2017 was at roughly its 2000 level on a Purchasing Power Parity (PPP) basis.
- Albania has performed relatively well. Over 2000-16 it grew by 4%/year and even by 2000 it had overtaken Ukraine on a per capita basis. (In 2000, Albania $5,500 per capita, Ukraine $4,700.) Ukraine remains the only FSU republic not yet to have regained its 1990 pre-USSR dissolution GDP level.[4] But Albania remains one of the smaller regional economies, and for example, the cost of Shah Deniz Stage 2 at just under $40 billion far exceeds Albania's 2016 GDP at $32 billion.

On institutional capacity, global rankings might provide an insightful indication on why the pace of adopting EU central gas market creation rules and regulations has looked sometimes frustratingly slow. Two widely cited global ranking exercises are those of Transparency International's Corruption Perception Index (CPI) and the World Bank's Ease of Doing Business (EDB).[5] Both rank a similar number of countries – 180 for TI and 190 for the doing business survey. From these there are some interesting observations for SE Europe:

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[4] All economic numbers come from the main indicator tables in the IEA's World Energy Balances, 2018 edition.
[5] Transparency International from www.transparency.org ; World Bank's 2019 doing business survey from www.doingbusiness.org

- Most countries in SE Europe come in at around a similar ranking position in both surveys. For instance, Slovenia is #36 in the CPI, and #40 in the EDB.
- Highest ranked country is Slovenia in both surveys.
- Most countries are in the middle area ranking position of between #60-120 in both surveys. For comparison, all the first EU members in W Europe come much higher up in the rankings.
- A high-level conclusion is that these surveys identify a general institutional problem and help illustrate why gas market development has been slow in SE Europe.

III. Gas market

SE Europe is not one cohesive or homogenous gas market. At the extremes, it contains one large mature market which has been consuming gas for over one hundred years (Romania), and a few very small markets like Bosnia & Herzegovina, and Albania with no market at all. The big similarity, however, is that the regional gas market developed as a number of disconnected island markets, all with high import dependency (apart from Romania) and none (except Greece) having access to LNG.

It is the legacy of little or no interconnectivity which is at the root of its current big strategic problems: slowness in completing the internal gas market requirements of the Energy Union; how to achieve a high degree of security of supply.[6] There are two dimensions to interconnectivity: the physical hardware of pipelines and the software of market and transportation rules and regulations – the Network Codes, implementing the Third Package. There have been substantial advances on the software side as the Third Energy Package requirements have been rolled out. This is the capex-lite side of delivery. It is the hardware side which is lacking and where the capex needs to be deployed.

Why capital is lacking is dealt with in Section V below, but in essence it is due to size (small economies, small gas markets, small TSOs); incumbent supply arrangements; institutional comfort with existing market structure; no new supply source pushing for access. All this is widely recognised, and indeed the CESEC initiative (see below) illustrates the acceptance of the point in Brussels.

Regional gas supply/demand

Total regional demand in 2016 was 25 Bcm, just 5% of the demand in the whole EU-28, with the region's EU-5 accounting for 90% of the volume.[7] Apart from Romania, there is very little production in the region. Croatia covers 60% of its demand from domestic output, but it is a small consumer, and Serbia has small production covering 20% of its demand. All others have negligible or no production. Regional import dependency therefore is high, with 50% of demand imported, and most of this comes from Russia. The only country with diverse supply is Greece with its LNG terminal and small pipeline imports from Turkey.

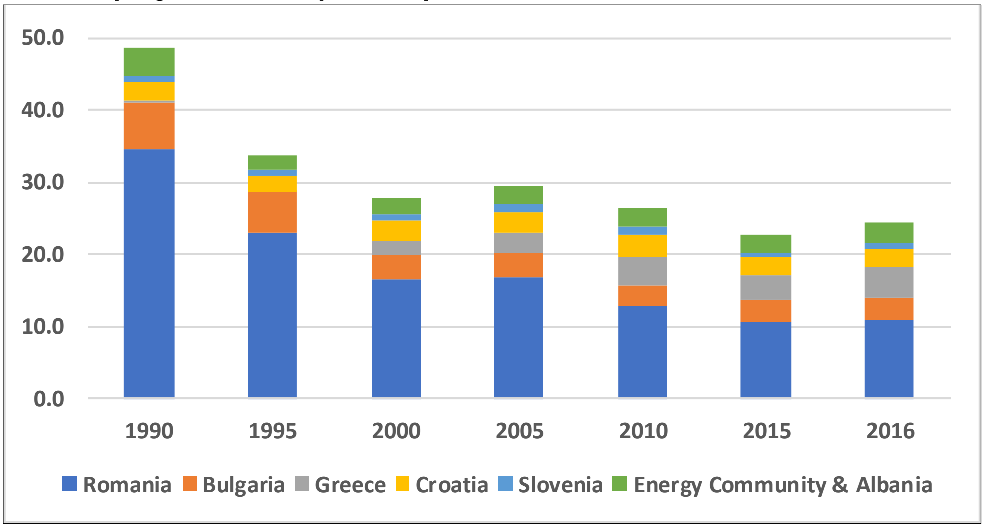
At a general level, the region has undergone demand erosion, variously caused by unravelling of the former Yugoslavia, debt-fueled recession (Greece), major industrial closures post-1990 (especially Romania), all of which have had lasting effects. In many respects, while we speak normally of growth or growth potential, for much of this region it is actually more like demand recovery, and for some of it demand creation from a zero base.[8]

[6] Julian Bowden, SE Europe gas markets – moving towards integration, in EU Energy Law Volume XI, The Role of Gas in the EU's Energy Union, ed Christopher Jones, Claeys & Casteels, 2017.

[7] Numbers taken from snapshot table above.

[8] Historical gas demand data in the chart taken from IEA World Energy Balances, supplemented where possible by data in the national TSOs' TYNDPs.

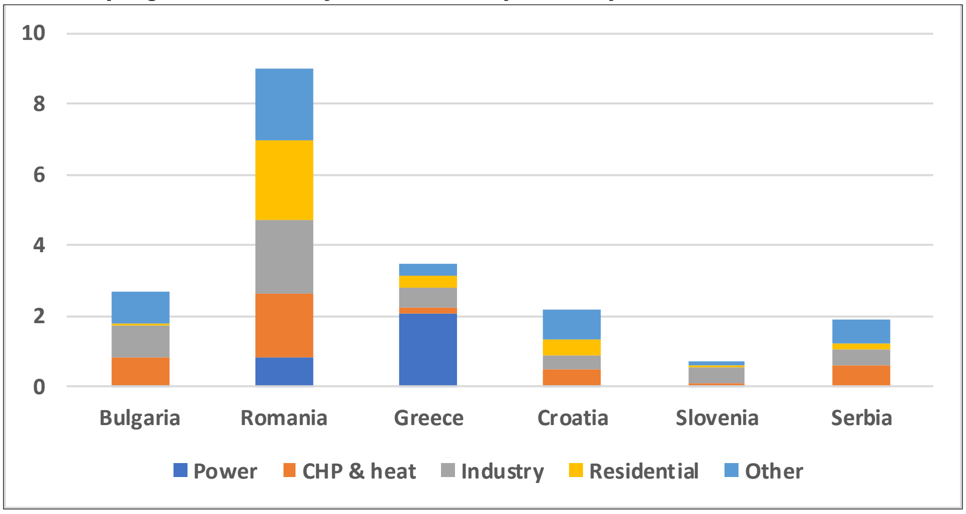
Figure 1: SE Europe gas demand (in bcma)



Source: IEA World Energy Balances

In terms of gas demand patterns, a striking feature is how little gas relatively is consumed by the power generation sector. The exception is Greece, but otherwise the two main consuming sectors are combined heat & power (CHP) and industry. Availability of CHP and district heating plants explains why direct gas demand in the residential sector looks to be small, and low demand in power is a reflection of high levels of lignite production in much of the region and its consumption in large mine-side power plants (see section below on the gas demand outlook and a potential upside for gas from lignite substitution).[9]

Figure 2: SE Europe gas demand by sector 2016 (in bcma)



Source: IEA World Energy Balances

[9] Gas demand by sector taken from IEA Energy Balances.

What follows is a brief narrative of the main features of each of the markets. They can be broadly divided by size into three groupings: one relatively large market (Romania); a number of 3-4 bcm markets (Bulgaria, Greece, Croatia, Serbia); one small (Slovenia) and then a number of very small one-consumer type markets or no market at all.

a) Large

Romania has by far the largest market in the region and is a country with the longest gas history in Europe: it was consuming gas in the early 1900s. By the 1980s it was a very large consumer, supplied largely by high domestic production but also by sizeable imports. In 1987 it produced a peak 38.5 bcm.[10] Imports from Russia have been a feature since the late 1980s, delivered through the Trans Balkan transit pipeline system (TBP) via Ukraine. Imports today from Russia and also Hungary are low, and fluctuate, but the market is within sight of being balanced.

In the early 1990s transition period the economy went into decline, contracting more than 10% over 1990-2000. Gas imploded: production halved, and as heavy industrial and petchem plants closed, consumption fell sharply. Production is dominated by two producers, Romgaz and OMV Petrom, accounting for 95% of national output and split almost equally at OMV Petrom 48% and Romgaz 46%.

The period of demand contraction has now ended, and for the last fifteen years or so the gas balance has more or less stabilised in the 10-12 bcma range. With imports from Russia and since 2010 from Hungary now at low levels, Romanian supply/demand is very close to being balanced.[11] If onshore production can be held at present levels, then the opening of the new offshore province would turn Romania into a small exporter by the mid-2020s. Given the low level of demand growth potential in the region, Romania alone could probably cover all of the region's incremental needs. If this happens, then space for more distant suppliers, such as the Southern Corridor from the Caspian or the Eastern Mediterranean, could be closed, and their gas would have to move further to find market.

Romania upstream

Onshore gas output is being held steady through a combination of rehabilitation and workover programmes on main fields, as well as some significant discoveries now coming on line. Caragele (Buzau county, 200 km NE of Bucharest) was hailed as the biggest discovery since 1989 when it was found by Romgaz in 2016. With a gas-in-place estimate of almost 30 bcm, it can produce 1 - 1.5 bcm/year, with production ramping up over 2019-20, which will stabilise onshore production levels.

But it is the offshore where the main production expansion is anticipated. The Black Sea Oil & Gas Midia project [12] comprising the Ana (2007 discovery) & Doina (1995 discovery) fields 120km offshore in 70 metres of water, took its FID in February 2019. The development plan has been approved by the National Agency for Mineral Resources for a mix of subsea wells and an unmanned platform over Ana. First gas is expected in 1Q2021. Capex is around $400 million, including the 126 km pipeline to shore, and on-shore gas treatment plant with capacity of 1 bcm/year. A long-term gas sales agreement with Engie is in place for 0.5 bcm/year, as is a 15-year transport agreement with Transgaz.

The much bigger development will be the Exxon/OMV Petrom discovery in the Neptun block in much deeper water. In 2012 Domino-1 was drilled 170 km offshore in 1000 metres of water and discovered

[10] Toplivno-energeticheskii kompleks SSSR v 1990, Vniiktep Moscow 1991, page 495.

[11] Romania gas balance data comes from 3 sources: TSO Transgaz TYNDP; regulator ANRE publishes a detailed monthly gas balance Raport monitorizare piata de gaze naturale; the State National Institute of Statistics publishes monthly energy stats in http://www.insse.ro/cms/en . For Romanian gas imports from Hungary, perhaps the best source is the Hungarian TSO FGSZ in its annual Data of the Hungarian Natural Gas System, e.g. page 55 of its 2017 edition. This also gives Hungarian transit of Russian gas to Serbia, exports to Croatia and Ukraine gas imports from Hungary.

[12] (BSOG - Carlyle group)

gas. Exploration and appraisal work on the field over 2008-2016 was reported at $1.5 billion for two 3D seismic campaigns, two exploration campaigns and eight exploration and appraisal wells. Neptun reserves are reported to be in the 1.5 – 3 tcf range, sufficient to support production of over 6 bcm/year.[13] Gas quality is said to be very dry.

It could be on-stream in 2021, but FID has not been taken yet. The main problem is the business environment. Market liberalising trends were being put in place: in June 2012 intent was announced to phase out regulated gas prices by 2015, and by 2016 to liberalise the purchase price of domestically produced gas, although regulated pricing to the residential sector would continue to 2021. The liberalising trajectory, however, looked increasingly threatened during 2018, and culminated in what is now the infamous Emergency Ordinance 114, introduced by the Romanian Government in December 2018. This introduced several illiberal provisions, such as a price cap of 68 Lei/Mwh (€14.60/Mwh) on domestic gas producers' sales to last for 3 years to February 2022 and a 2% turnover tax.[14]

Rumours emerged in July 2019 that Exxon wanted to divest.[15] While rumours continue of OMV Petrom and Carlyle interest in picking up the stake, resolving any such ownership stakes can only delay FID further.

Meanwhile, Transgaz is planning to build capacity to move Neptun gas once it is onshore. There is significant risk that the legislative uncertainty caused by Emergency Ordinance 114 will create further delay or even cancellation, thereby making the pipeline investment plans around BRUA Phase 1 completely desynchronised from the gas flow.[16]

There is other upstream activity also. Lukoil announced a gas discovery in the nearby Trident block from its Lira-1 well in October 2015, with a potential resource of 30 bcm.[17] Offshore neighbouring Bulgaria, Total, Repsol and OMV are working on the Khan Asparuh block, and Shell on Khan Kubrat.[18]

b) Intermediate 3-5 bcm/year markets

Bulgaria Apart from 2009-10, when it was caught in the global downturn and demand fell by one-third, consumption has been steady in the 3.0 – 3.5 bcm/year range for the last 20 years. Like many markets in the region, demand shows high seasonality, which is managed by storage operations through the Chiren underground storage facility and also by some import flexibility. With insignificant domestic production, supply is over 95% met by Russian imports.[19]

Greece Demand was on an upward trajectory until the global recession of 2008-9, and then the recovery was knocked back by the country's profound financial crisis, causing demand to fall to under 3 bcm/year. It has since recovered strongly to approach 5 bcm in both 2017 and 2018. Of all countries in SE Europe, and while Russian supply dominates (delivered through the Trans Balkan Line via

[13] Project information taken from the BSOG, Exxon and OMV websites. Potential production from Neptun is variously given in the 5-6 bcma range. Exxon's country manager Richard Tusker reportedly said in June 2018 that 6.3 bcma was possible - https://www.romania-insider.com/exxonmobil-extract-gas-black-sea/

[14] http://www.ropepca.ro/en/articole/the-giant-project-of-exxon-and-petrom-in-the-black-sea-threatened-the-parliament-forces-that-70-of-the-gas-production-be-sold-on-opcom-exchange/503/

[15] https://globuc.com/2019/07/15/exxon-wants-to-pull-out-of-romanian-offshore-gas-project/

[16] Transgaz capex for all its projects is in the Transgaz TYNDP 2014-23, p 48. BRUA – Bulgaria-Romania-Hungary-Austria – is a 2-phased redevelopment of a substantial portion of the Romanian pipeline system and enhancement to handle the offshore gas. See John Roberts, Three Pipelines & Three Seas: BRUA, TAP, the IAP and gasification in Southeast Europe, Atlantic Council September 2018.

[17] http://www.lukoil.com/PressCenter/Pressreleases/Pressrelease?rid=50864 14th October 2015

[18] Bulgartransgaz TYNDP 2019-2028, page 17

[19] Bulgaria gas supply/demand given in the Bulgartransgaz TYNDPs. Historical numbers, by month, are available also from the national statistical institute NSI in http://nsi.bg/en/content/5024/production-and-deliveries-natural-gas

Romania and Bulgaria) it does have the most diverse supply, with LNG and small pipeline imports from Turkey.[20]

Croatia is a 3 bcm/year market. It has the second highest cover from domestic production in the region after Romania, although this is eroding fast. Production comes from offshore Adriatic and onshore fields. The onshore is stable; the offshore is on steep decline. Offshore is a joint INA-AGIP business, and the export numbers in its balance reflect the share going to Italy.[21] In total, domestic production met around 68% of demand in 2012, but 44% in 2018. The consequence is a rise in imports, which enter via the interconnectors from Slovenia and Hungary. About 45% of demand is from the power generation and especially heat cogeneration sectors.

Serbia's demand in 2017 was 2.7 bcm, up 12% on 2016.[22] The market is extremely concentrated between State gas company Srbijagas and Gazprom throughout its supply and distribution chain, a point emphasised frequently in the Energy Community Secretariat's regulatory Opinion on the Gastrans pipeline (see below). Gas output is small, covering around 20% of the market and NIS (56% owned by Gazprom) is the sole producer. The remaining supply is imported from Russia. The system has one entry point at Hungary's Kiskundorozsma crossing point, with a technical capacity of 4.55 bcm/year and one exit point at Zvornik for onward delivery of Russian gas to Bosnia & Herzegovina.[23]

Gazprom Export sends gas via an intermediary, Yugorosgaz, under long-term contract to Srbijagas. The ultimate owners of Yugorosgaz are Gazprom 75% and Srbijagas 25%. The LTC runs until 2021 and provides 1.8 bcm in 2018 and up to 2 bcm/year to 2021, although actual imports were higher in 2017.[24]

c) Very small under 1 bcma markets /no market

Slovenia Demand in 2017 was 0.9 bcm, supplied roughly half from Russia and half from the Austrian hub. There have been small imports credited to Algeria, but these ended in 2013.[25] It is relatively well interconnected. The main entry point is from Austria and the main exit point is to Croatia, supplemented by a smaller bi-directional link with Italy. Most demand is from industry. Power sector demand is tiny, in part because of the 700 MW nuclear plant at Krsko, a JV with Croatia which started commercial operations in 1983.

Bosnia & Herzegovina Demand is a very small 0.2 bcm/year, all supplied from Russia via Serbia. There are plans for a connection from Croatia, perhaps being built as a spur from the 5 bcm/year IAP pipeline running from TAP in Albania through Montenegro to Croatia.

Republic of North Macedonia Demand is around 0.2 bcm/year, all supplied from Russia via Bulgaria and the Trans Balkan system.

Albania has tiny production associated with its small oil production, but the gas is all used at the field. There is no commercial market. In 2015 a Gas Master Plan was completed, funded by the West Balkan Investment Framework (WBIF, i.e. the EU), which concluded that the potential for demand by 2030 could lie in a 0.5 – 1.5 bcm/year range. The TAP pipeline is under construction, and its Albania section is almost complete, but no Shah Deniz Stage 2 gas has been contracted for delivery into Albania. A project developer, Eagle LNG, has pursued an FSRU project located offshore Fier, which would serve

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[20] Greece gas supply/demand history taken from the Greek TSO DESFA, DESFA Development Study 2018-27, published June 2017, pp 5-9, available on the DESFA website.
[21] A very detailed Croatia gas balance is published annually by the Croatian Gas Association.
[22] Serbia gas balance from Statistical Office of the Republic of Serbia.
[23] For Serbia's imports of Russian gas via Hungary, see the FGSZ annual Data of the Hungarian Natural gas system, op cit.
[24] The Energy Community Secretariat's (ECS) Opinion on regulatory aspects of the trans-Serbia pipeline Gastrans, to be built to handle Turk Stream Line 2 gas, contains excellent detail of the structure of Serbia's gas market. See ECS Opinion 1/2019 on the exemption of the *Gastrans* natural gas pipeline project from certain requirements under Directive 2009/73/EC.
[25] Slovenia TSO Plinovodi's TYNDP 2017-2026

both Albania and Italy, but this looks currently dormant. In May 2019, Shell announced a discovery of several thousand barrels/day potential from its Shpirag–4 well near Berat, some 70 km south of Tirana.[26] In a small market even a small gas discovery would make a significant difference to the supply/demand balance.

Neither **Montenegro** nor **Kosovo** has a gas market at present.

Gas demand outlook

The projection below has been based on the individual TSO submissions to ENTSOG in the most recent 10-year Network Development Plans (TYNDP) exercise. ENTSOG compiles the numbers, but generally does not review the national TSO submissions. The demand outlook does tend to change from TYNDP to TYNDP: for instance, the Romanian TSO Transgaz is now showing flat demand, while DESFA has raised the outlook for Greece.

Table 2: SE Europe gas demand growth outlook 2016–2026, incremental demand 2026 from a 2016 base in bcm

	(1)	(2)
Bulgaria	1.2	1.2
Romania	2.3	flat
Greece	-0.3	1.1
Croatia	0.2	0.2
Slovenia	0.4	0.4
Albania	0.0	0.5
TOTAL	**3.8**	**3.4**

(1) ENTSOG, Southern Corridor GRIP 2017-26, Annex C demand data. Demand up 2% pa
(2) shows change on (1) from later numbers from the DESFA & Transgaz TYNDPs

Source: TSO Ten-Year Network Development Plans; ENTSOG

Aggregating the numbers for the EU-5 gives a demand growth of just under 4 bcm/year by 2026.

The Albania forecast is derived from its Gas Master Plan and is clearly dependent on investment in laying some grid network and kick-starting the market once supply becomes available.

Growth of around 4 bcm/year seems a reasonable projection for the region, meaning growth of 2%/year. In this time frame, whether or not there is any growth or market development in the other very small markets makes no material difference to the regional volume. Note that 2%/year growth is not out of line with recent GDP performance across the region (minus Greece).

At the European level, the growing requirement for imports over the next decade comes not from demand growth, but more from supply decline in the North Sea and the Netherlands. In SE Europe on the other hand, despite the likely decline of Croatia production, the driver is more from demand growth.

Two points stand out here:

[26] Reuters, 24th May 2019

- If Romania can begin its offshore projects, then the ~5 bcm from Neptun could fill the region's incremental growth, if sufficient interconnector capacity is available to move the surplus.
- The demand pull in the region for gas from the Southern Corridor, East Mediterranean or elsewhere looks to be very small, meaning that gas will need to move further westwards to find market and /or competitively force itself into Turkey. But getting the gas to go further north to larger markets in Europe looks hard, because greater distance means greater transportation costs and therefore lower netbacks.

In the TSO submissions on future demand, there is no decarbonisation scenario in which gas captures market share from coal. This is not to say that the TSOs are wrong to exclude such a scenario, simply that coal removal from the mix does not appear to be on the policy agenda. Coal accounts for a substantially larger share of energy consumption than gas in SE Europe. In 2016, 17% of the region's total energy consumed came from gas, 27% from coal. This coal volume, 32 Mtoe, is equivalent to 38 bcm/year of gas.

- Most of the coal tonnage is lignite. In 2018, the region produced 4.8 million tonnes of hard coal, but a massive 157 million tonnes of lignite.[27]
- Romania, Bulgaria, Greece and Serbia are all significant lignite producers. In total, SE Europe produces one-third of Europe's lignite (including Turkey's lignite). SE Europe's EU-5 produces 25% of the EU's lignite, the largest two EU producers being Germany and Poland.
- For two countries – Greece and Bulgaria – lignite is the main indigenous energy resource.

With these coal volumes, SE Europe is for once not on the European energy periphery. Because it is a low quality fuel, lignite is not internationally traded: typically, it is mined and transported to a nearby power station, thus creating an integrated operation. For example, in Greece, the major lignite producer is the 51% state-owned Public Power Corp (PPC), which has 6 lignite-fired plants totalling 4.3 GW capacity. In 2015, total Greece lignite output was 45.4 million tonnes, of which the PPC share was 80%.[28]

Much of the industry in SE Europe is subsidised. The Energy Community Secretariat estimates annual direct and indirect subsidies in its SE European members at over €2 billion (€400 million direct, up to €1.9 billion indirect[29]). Despite this cost, the barriers to removal are a formidable mix of social and political factors:

- Employment: coal mining is an integrated operation, employing over 110,000 people directly in mining and indirectly in power generation. About half these are in Bulgaria.
- Integrated operation: coal production and the associated power generation must be taken together.
- Indigenous resource: for some countries – Greece, Bulgaria, also Serbia - coal is an important or the sole domestic energy resource.
- Import cost: alternative imports of, say, gas, would hit the balance of payments or, to avoid that, would require a domestic renewables programme on a major scale.
- For reference, displacing all the coal would be equivalent to 38 bcm/year of gas.

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[27] All data from Euracoal – the European Association for Coal & Lignite. European coal industry's umbrella organisation, Euracoal produces comprehensive market reports and country reviews.

[28] Euracoal, Greece country profile

[29] Energy Community Secretariat report 'Rocking the boat: what is keeping the Energy Community's coal sector afloat?' June 2019, pp 5

Policymaking is unclear, but it seems to be sluggish and contradictory, and there is little appetite for immediate and drastic action. For example, addressing a recent conference in Bucharest, Romania's Energy Minister said: "Romania will keep using coal, like many other European countries". Yet a few moments later at the same event, a senior official from his Ministry said coal has only a limited future.[30] In a recent report by the ECS, there was evident frustration with the lack of progress, and the ECS was unequivocally critical of its members. Noting that coal still represents 46% of the total installed generating capacity in its Contracting Parties, the ECS wrote unambiguously: "The Contracting Parties are not prepared to follow the EU in its decarbonisation pathway". Moreover, "coal has become an obstacle on the Energy Community Contracting Parties' paths towards EU accession and meeting their commitments under the Paris Agreement on climate change".31 Overall, it seems unlikely that within the time horizon of the TYNDPs (i.e. mid-2020s) there will be any significant policy-induced contraction of the region's lignite industry.

IV. Regional gas flows – impact of Turk Stream

From South Stream to Turk Stream

In common with many pipeline projects, both large and small, Turk Stream has had an evolutionary history. In 2007, an MOU was signed between Gazprom and ENI for what became South Stream. The plan was to build a 4-string system totalling 63 bcm/year capacity some 920 km across the Black Sea from a start point at the Russkaya compressor station near Novorossisk to a landfall near Varna in Bulgaria. (The technical issues of laying and operating a pipeline across the sometimes 2.1 km deep Black Sea had been solved by the 16 bcm capacity Blue Stream. Blue Stream commercial operations started early in 2003 and have had a good operational track record since.)

The strategic intent behind such a large system can only be speculated, and it probably evolved. Clearly, the Russia-Ukraine gas relationship was not as poor in 2007 as it became after 2009 and the Russian drive to create a total Ukraine by-pass capability was not so obviously defined as it became later. At this stage, therefore, it was probably at least as important to confront the competitive challenge of the Southern Corridor and the Nabucco project for a 30 bcm/year pipeline from Baku to Baumgarten.

South Stream's plan was to build two of the 32-inch, 15.75 bcm/year lines initially. Pipelay contracts for the offshore section were signed with Saipem (which had laid Blue Stream), linepipe was ordered and stored in Bulgaria, on-shore work in southern Russia was completed to provide gas at Russkaya. One major problem with such a large flow was to work out how to move the 60 bcm onwards from the Bulgaria landfall. Several routings were sketched on several maps: variously a dual-system southern leg to southern Italy and a northern leg towards Baumgarten; a northern routing with a fork to northern Italy and another fork to Baumgarten via Hungary.

It was always subject to geopolitical challenges, and once Russia had annexed Crimea in 1Q2014 these intensified. As the EU threw pipeline regulatory rules at the onshore ideas, South Stream was abruptly cancelled at the end of 2014. It is conceivable that by this time Russia was grateful for a gracious escape, because with investment and managerial resources required on Nord Stream 2 and Power of Siberia, financing and developing a third major pipeline might have looked hard.

Turk Stream

Turk Stream emerged in 2015 as a radically reconfigured South Stream. A system half the size is envisaged, 31.5 bcm in 2 lines, the same start-point but terminating now in NW Turkey instead of EU

[30] Energy Strategy Summit 'Mapping the Future' Energynomics conference in Bucharest, 11th June 2019

[31] ECS 'Rocking the boat' op cit, pp 5, 22

Bulgaria. Capex for the offshore Black Sea section was estimated at €7billion,[32] excluding the onshore Russia work and the pipeline(s) in SE Europe.

The project took shape very quickly, as the routing and engineering was mostly the same as for South Stream. BOTAS and Gazprom signed the MOU almost at the same time as South Stream was cancelled and in October 2016 the Russian & Turkish Governments signed the agreement to build it. In December 2016 Allseas was contracted to lay the 2 offshore lines, and work started in May 2017 using the world's largest laybarge, *Pioneering Spirit*. Pipelay was finished in November 2018, an event marked by Presidents Putin & Erdogan at a completion ceremony in Istanbul. It was a very impressive technical achievement: in just under 18 months 2 x 920 km pipelines had been laid. Average pipelay speed was 4.3 km/day, and on a couple of days 5.6 km was managed.

At the Turkey landfall at Kiyikoy west of Istanbul, the connection between the offshore and nearshore pipelines was made in March 2019 and the receiving station will be ready by autumn 2019. The schedule for first gas by December 2019 looks very realistic, especially for Line 1 gas which is dedicated to Turkey. There is a near perfect fit between Line 1 capacity of 15.75 bcm/year and current Russian export volumes to Turkey through the Trans Balkan Pipeline system (TBP). Given that it is not clear whether the 15.75 bcm is an annual maximum capacity, or whether maintenance down-time and other factors are included, the current Russian flow of 10-13 bcm/year to Turkey can be immediately diverted from Ukraine and the TBP into Turk Stream Line 1 and basically fill it.

Table 3: Russia gas exports to Turkey via Blue Stream & Trans Balkan Pipeline (in bcm)

	2011	2012	2013	2014	2015	2016	2017	2018
Turkey total imports from Russia	26.0	27.0	26.7	27.3	27.0	24.8	29.0	24.0
delivery route:								
Blue Stream Russia-Turkey	14.0	14.7	13.7	14.4	15.7	13.1	15.9	13.3
Trans Balkan pipeline	12.0	12.3	13.0	12.9	11.3	11.7	13.1	10.7

Sources: Gazprom in Figures, annual Factbook for Blue Stream flow to Turkey; Gazprom in Figures, annual Factbook for total exports to Turkey; Bulgartransgaz TYNDP 2016–25 & 2018–27 confirm the number to Turkey via the TBP

The onshore problem is Turk Stream Line 2. The 140 km pipeline from the Kiyikoy receiving station to Malkoclar on the Turkey-Bulgaria border, operated, by a 50:50 JV between Botas and Gazprom, remains to be built. The initial capacity is understood to be 10 bcm/year, with expansion to 17 bcm/year possibly by 2022. At Malkoclar it will connect into the existing TBP, which will then operate in reverse flow back into Bulgaria.

Table 4: Ukraine transit – impact of Turk Stream, Russian exports in 2018 through TBP (bcm)

	2016	2017	2018
Turkey (diverted into TS Line 1)	11.7	13.1	10.7
diverted into TS Line 2:			
Bulgaria	3.2	3.3	3.2
Greece	2.7	2.9	3.3
Rep of N Macedonia	0.2	0.2	0.2
Romania	1.7	1.4	1.5
total TS Line 2	7.8	7.8	8.2
Total via Trans Balkan diverted into TS1 & 2	**19.5**	**20.9**	**18.9**

Source: Gazprom in Figures 2014–18, p78

[32] Gazprom investor presentation February 2017, slide 13 http://www.gazprom.com/investors/presentations/2017/

To maximise Ukraine diversion, Russia will need to put all its Greece, Bulgaria and Republic of North Macedonia exports into TS Line 2, use the new interconnector to the Bulgarian border and then into the reversed TBP. In 2018 these exports totalled 6.7 bcm.[33] If Romania is included (1.5 bcm Russian imports in 2018) then the total would be 8.2 bcm Therefore, on 2018 volumes, in 2020 Russian should be able to divert 19 bcm away from Ukraine (see table above).

The regional impact of Turk Stream will be significant:

- It will change the region's gas flow patterns. Virtually overnight, the 25 bcm/year TBP system will become empty and up to 19 bcm/year will be removed from Ukraine transit during 2020.
- For the TSOs concerned, there is potential loss of significant transit revenues.
- It will facilitate SE Europe's interconnectivity through the building of onward Line 2 capacity through Bulgaria and Serbia.

Transit across Bulgaria and Serbia

After much speculation on how Gazprom might plan to move Turk Stream Line 2 gas into and through SE Europe (with questions such as - would it bid for TAP expansion capacity to southern Italy or not?) its chosen path now seems settled on a Bulgaria and Serbia routing to Hungary.

On current flows, the problem for Gazprom seems to be transporting 9 bcm/year. If we assume Romania becomes balanced in the early 2020s (with no more need for Russian imports) and that Bulgaria, Greece and Republic of North Macedonian exports (6.7 bcm) can be delivered through partial reverse of the TBP and then using the existing pipeline into and through Bulgaria to Greece, then the 'problem' becomes 15.75 bcm minus 6.7 bcm, (9 bcm) to be moved into Serbia from Bulgaria. Gazprom exports to Serbia in 2018 were 2.2 bcm, so around 7 bcm will need to exit Serbia.

The *Gastrans* project is to build a 400 km pipeline across Serbia thereby linking Bulgaria and Hungary. Details include: technical capacity 13.9 bcm/year; 3 offtake points in Serbia totalling 3.8 bcm/year, leaving 10.1 bcm/year at its exit point in Hungary. Gastrans is wholly owned by South Stream Serbia AG, registered in Switzerland, which is in turn owned 51% by Gazprom subsidiary PJSC Gazprom Transgaz Krasnodar and 49% by Srbijagas. An application was made by the project to the Serbian regulator AERS in February 2018, requesting exemption from Third Energy Package provisions on unbundling, third-party access and tariff regulation. Unconfirmed capex estimate is around €1.0 billion. Construction was planned to start in summer 2019, to be completed by 2022.[34]

AERS has allowed 88% of the capacity to be reserved for the exclusive use of Gazprom and/or Srbijagas. This decision then went to the ECS for its approval. ECS reduced the reserved capacity to 70%, (9.7 bcm/year) which would give plenty of capacity for transporting the remaining TS Line 2 volume of 6.8 bcm/year beyond Serbia *and* provide for 30% third party access.

Bulgaria, meanwhile, has proceeded down the route of holding an open season, requesting the market to indicate what capacity it needs and then planning appropriate capacity. The process has gone through the non-binding to the binding stages. In January 2019 Bulgartransgaz announced that it had sufficient volume committed in the binding phase to proceed with a new pipeline with expected capex of BGN 2.7 billion ($1.6 billion).[35]

Despite what the participants might say, building the line through Bulgaria and Serbia to synchronise with Turk Stream commissioning is clearly impossible by end-2019. A reasonable earliest date for its

[33] Gazprom in Figures 2014-18 Factbook, p 78
[34] Bulgartransgaz TYNDP 2019-28, page 38
[35] https://balkaneu.com/bulgarias-bulgartransgaz-closes-open-season-on-turkish-stream-onshore-extension/

completion, given permitting, financing, construction and commissioning would seem to be 2022-23. If this all works - and Brussels so far has made no moves to intervene because the regulatory processes seem to be being followed well - then implications would include:

- Maximum utilisation of Turk Stream's 31 bcma capacity would be possible by end-2022. (That is, a further reduction of 12 bcm/year in transit through Ukraine on top of the 19 bcm/year possible from early 2020).
- Flows through Baumgarten should be unchanged, as gas diverted through Line 2 will still enter Austria from Hungary.
- The Gastrans project calls into question whether the planned IBS interconnector between Bulgaria and Serbia is necessary.

Turk Stream Line 2 – Regulatory issues around the Serbia *Gastrans* pipeline

There are two main documents: the Serbian regulator AERS Decision of October 2018, granting an exemption; the response of the Energy Community Secretariat (ECS) in February 2019 giving its own Opinion on the AERS Decision. In the Opinion the ECS, in a thorough critique, dismembered the AERS arguments and requested several conditions and changes.[36] Its main reference point is the tests on competition, security of supply and unbundling which should be applied, as set out in Article 36 of Directive 2009/73/EC.

AERS in its Decision allowed 88% of capacity to be retained by Gazprom and/or Srbijagas for their exclusive use. The main headline is that the ECS reduced the capacity available for the exclusive use of Gazprom & Srbijagas from 88% to 70%. 12% of the capacity available for third party access would be insufficient to attract other potential suppliers and stimulate any supply competition, while 30% would.

The ECS recognised that Serbia is fully dependent on one import route from the north via Hungary. But, its market is highly concentrated with the two Gastrans shareholders Gazprom & Srbijagas being in complete control of the whole chain. Gazprom Export supplies 80% of demand though its exports, and Serbia's production is operated by NIS which is in turn majority owned by Gazprom.

Storage of 0.45 bcm is owned by Srbijagas 49% and Gazprom Germania 51%.[37]

ECS also took account of concerns of the Hungarian and Bulgaria regulators that: 88% reserved capacity would have a negative impact on the development of both competition and market integration; there should be a single regulatory regime based on the CAM Network Code over the whole system, as without that it would frustrate offering the market harmonised incremental capacity across the three countries.

ECS found that with the problem of market domination by two players and potential foreclosure on upstream and supply, and that second shareholder Srbijagas dominates the Serbian gas downstream, there is huge market concentration and barriers to competition "so the assumption that Gastrans as developed by these undertakings will enhance competition cannot be substantiated".[38] The project and the AERS Decision "do not enhance competition…..but on the contrary, strengthen the market position of the dominant undertaking Gazprom". The AERS Decision in effect strengthens the position of the incumbents, and the 88% exclusive allocation of capacity actually restricts competition on the Serbian and also Hungarian and Bulgarian markets.

[36] Energy Community Secretariat, Opinion 1/2019 on the exemption of the *Gastrans* natural gas pipeline project from certain requirements under Directive 2009/73/EC by the Energy Agency of the Republic of Serbia.
[37] ECS Opinion, op cit, paragraphs 60, 74.
[38] Paragraphs 62-63

ECS conceded yes, Gastrans would enhance security of supply in Serbia and the SE Europe region, but only through opening a new transportation route and not by providing access to any new sources of gas. The project could either become a partial substitute for the existing route into Europe of Russian gas via Ukraine, or just offer incremental capacity for more Russia exports to Europe.[39]

Further, the 12% non-exempted capacity was not enough to enable short-term flexibility for new supply which might become available from the Greece-Bulgaria interconnector (IGB) or new production from the Black Sea. Reverse flow should be built in, in accordance with Article 5 of regulation (EU) 2017/1938. The AERS Decision asks Gastrans to test market interest in expansion and reverse flow every 6 years, a far longer period than the every 2 years in Article 26 of the CAM Network Code. ECS agrees the investment would not happen without an Exemption: there is financial risk, but the 88% exemption is not a proportionate mitigation. [40]

ECS Opinion

Overall, the ECS reduced all the percentages available for the exclusive use of Gazprom and/or Srbijagas in order to allow other participants opportunity to enter the Serbia gas market. Gastrans should reduce the capacity reserved to Gazprom Export and Srbijagas from 88% to 70%. A minimum 20% of total technical capacity should be sold via auctions on an annual basis, preferably on the same booking platforms as used by Bulgaria and Hungary as long-term non-exempted capacity, and 10% sold for short-term capacity booking. On the 3 exit points inside Serbia, only 55% should be exempted: 35% long-term and 10% short-term capacity should be available to be sold to others (paragraphs 185-186). 30% of the volume put into Gastrans in Serbia should be available to third party marketers. This volume is to be delivered at the Virtual Trading Point in Serbia. Physical reverse flow should be enabled for emergency supply from Serbia to Bulgaria.[41]

However, this is not the end of the story. AERS has not accepted all of the ECS Opinion, and it remains possible that regulatory issues will delay completion of this project.[42]

The Trans Balkan Pipeline system (TBP)

The TBP was built in the 1980s south from Ukraine along the Black Sea coastline through Romania and Bulgaria. In Bulgaria the system splits, with the larger flow heading east to Turkey and a smaller flow westwards to Greece and the Republic of North Macedonia. The system was expanded as Russian exports into the region increased. Russian exports to Turkey started in 1987 through this system, and to Greece in 1992.[43]

In Romania, there are 3 lines, as follows:[44]

	Diameter mm	Length km	Bcm capacity
• Line 1	1000	182	5.3
• Line 2	1200	181	10
• Line 3	1200	181	10

[39] Paragraphs 120, 115.

[40] Paragraphs 115, 116, 119, 121, 144

[41] Paragraphs 179, 180, 185, 186, 179, 180

[42] At the ECS annual Gas Forum in Ljubljana 24th-25th Sept 2019, ECS Deputy Director Dirk Buschle commented that AERS had followed some of the ECS Opinion, but not the parts on capacity allocation and building a competitive market. He said: “Serbia is still not compliant with the 2nd package, yet alone the 3rd Package”; “The Serbian gas market is almost the worst in Europe in terms of openness and competition”; and in rejecting much of the ECS Opinion “Serbian market building is effectively lost now for the next 20 years”.

[43] Per Hogselius, Red Gas – Russia and the origins of European energy dependence, Palgrave 2013, p 200

[44] Transgaz TYNDP 2014-2023, p 6

Total technical capacity in Romania is 25.3 bcm/year. In Bulgaria, the system funnels down to a smaller system with technical capacity of 17.8 bcm/year.[45] In 2018, total transit flows through Bulgaria were 14.2 bcm, down from 16.3 bcm in 2017 because of lower Russian deliveries to Turkey.[46]

Table 5: Bulgaria - Bulgartansgaz transit volumes (bcma)

	2006	2010	2016	2017	2018	system capacity
Turkey	12.4	10.0	11.8	13.1	10.7	14.0
Greece	2.7	2.1	2.7	2.9	3.3	3.0
Rep of N Macedonia	0.1	0.1	0.2	0.3	0.3	0.8
Total	**15.2**	**12.2**	**14.7**	**16.3**	**14.2**	**17.8**

Source: Bulgartransgaz various TYNDPs

Turk Stream impact on TSO revenues –Transgaz and Bulgartransgaz

Both Transgaz and Bulgartransgaz derive significant revenues from transit of Russian gas through the TBP system. For Romania's Transgaz, over the last 6 years, between 18%-20% of its total operating revenues came from transit operations. However, for Bulgartransgaz the revenue is very substantial, around 60% for the last 4 years.[47] The reason for the disparity seems to be that Transgaz operates a much larger system handling larger domestic volumes and transit distance is much shorter. The Romanian market is almost four times the size of the Bulgarian one (11 bcm vs 3 bcm), and transit is only 200 km across Romania.

Loss of transit revenue would be significant for both TSOs, and especially so for Bulgartransgaz. Consequently, both TSOs will be incentivised to find alternative business for a pipeline system about to become empty. For Transgaz, it could be the new offshore gas. For Bulgartransgaz, it could be maintaining at least some revenue through reverse flow to maintain Russian gas transit to Greece and the Republic of North Macedonia and then though the new Turk Stream Line 2 evacuation to Serbia. For both, there could be reason to explore options such as potential exports to Ukraine. There are some small signs that this is happening: for instance, the new Greece LNG regas terminal project (possibly located at Alexandroupolis) includes Ukraine as a potential market for gas being delivered through a reversed TBP.

V. Building interconnectivity

As noted earlier, the evolution of gas development in the region led to the creation of island markets, with little or no interconnection between them. The main transit system into the region, the Trans Balkan Pipeline system, placed Russian gas in all the markets, but did not enable any kind of independent flow between them. EU energy policy pillars of completing the internal gas market and achieving security of supply throughout the region will always be frustrated unless physical pipeline interconnectors are

[45] Bulgartransgaz TYNDP 2019-2028, p 12

[46] Bulgartransgaz TYNDP 2016-2025, p 26; Bulgartransgaz TYNDP 2018-2027, p 40

[47] Transgaz financial statements for year-end December 2017 and Transgaz consolidated report to Board of Administration 2017 (both available on Transgaz website); Bulgartransgaz financial reports December 2017, which are available in English in the Bulgarian Energy Holdings (BEH) website.

built.[48] As the Bulgarian gas regulator commented recently, "since antiquity, roads have cemented marketplaces".[49]

Many interconnector projects have been thought about, some with a project organisation, very few yet built. The first involved Hungary, where FGSZ for long seemed to be the most organised and dynamic TSO in the larger region. In October 2010 the Hungary-Romania interconnector was commissioned after an FID taken in January 2008. From Szeged to Arad, it is a 109 km, 700 mm line (62 km in Romania, 47 in Hungary). Capacity is 1.75 bcm/year, but the design would allow up to 4.5 bcma. Cost was €68 million. The EU provided €17million via the European Energy Recovery Programme EERP; this line was the first project implemented under this funding, which had been set up in 2009.[50] The flow is Hungary to Romania, because the older Romanian system operates at a much lower pressure than the modern Hungarian 75 bar, and will require a compressor to enable a bi-directional flow.[51] The longer Hungary-Croatia interconnector was built in 2011, 206 km in Hungary, 88 km in Croatia. The flow is in a Hungary-Croatia direction only until there is new investment in a Croatia compressor.[52]

Then there was nothing until the small and short Bulgaria-Romania interconnector was finished in 2016 from Ruse to Giurgiu, just 25 km. FID was taken in 2010, and the 1.5 bcm/year capacity project cost €24 million, of which the EEPR provided €9 million. One problem was the Danube crossing, where there were delays from choosing the right location for the horizontal drilling of two narrow tunnels and then the right contractor. Two pipes were laid under the river, one as a back-up, so if there is capacity expansion on each side of the river the capacity could theoretically be doubled. The line has been very little used so far.

All the projects listed in the CESEC priority list (below) have been around for many years and in some cases over 10 years, but apart from the above and a small link from Romania into Moldova, nothing else has been completed. The problems with building interconnectors have been several and overlapping:

- **Supply** Where is the supply to come from? The Southern Corridor system TANAP-TAP is driven by the Shah Deniz Caspian upstream, but it is not clear where the supply for many of the CESEC interconnectors is to come from.
- **Size and function** Are they to serve one market, or several markets and with multiple cross-border crossings, or both? How to finance pipelines where costs and benefits are disproportionate (for instance IAP, where most of the costs are in Croatia. ACER does now have an apportioning methodology). Specifically on size, if the pipelines are small they will need expanding later if they are to serve a future transit function. And on function, if the primary objective is security of supply, how is a pipeline that will basically only be used in an emergency to be funded? Commercial funding would require a pipeline to be used as close to capacity as possible in order to generate maximum cash flows.
- **Sequencing** There is little point in building Bulgaria-Serbia, unless Greece-Bulgaria is built first.
- **Coordination** The LNG regas terminals planned for Croatia and Greece are too large for their national markets, so will require interconnectors to provide onward transportation to other markets. How is IAP to work with Croatia LNG when IAP itself would almost certainly need to be able to flow gas beyond Croatia? How do some projects complement each other?

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[48] Julian Bowden, SE Europe gas markets – moving towards integration, in EU Energy Law Volume XI, The Role of Gas in the EU's Energy Union, ed Christopher Jones, Claeys & Casteels, 2017, page 73

[49] Alexander Yordanov, Bulgaria's gas regulator in Bulgaria's EWRC regulatory commission, at the BBSPA annual conference, Bucharest, 4th April 2019.

[50] See https://www.hydrocarbons-technology.com/projects/arad-szeged-pipeline/

[51] For flows since commissioning, see FGSZ, Data of the Hungarian Natural Gas System, 2017, p 55

[52] Ibid, and Croatia TSO Plinacro website, press announcement Aug 2018,

- **Small TSOs** The region's TSOs are mostly small, and also have ageing domestic systems. (Croatia is an exception here with a modern domestic system). The costs of even a small interconnector could look relatively large in the total asset base. In a large market it would be easier to spread the costs through the total asset base; the impact would be diluted. In what might be a large transit line, an interconnector becomes a large undertaking relative to the rest of the system.
- **Commercial vs State / EU funding** A small, underutilised interconnector will always struggle to make a compelling commercial case. Or, it might become more utilised later once potential supply become firm supply, but in that case an interconnector project may look like pre-investment.
- **Market size** A small interconnector of say 3 bcm/year (IGB's initial capacity is 3 bcm/year) appears huge in a 3-4 bcm/year market. In NW Europe, though, small interconnectors would probably be a small component of the overall asset base, or easier to justify in terms of security of supply for an undefined eventuality or general market building aspiration.
- **Political resistance** is very hard to measure but would explain why interconnector ideas which have been around for over ten years have not progressed.

The above suggests why progress has been very slow. Especially important is supply and market size: without a supply champion looking to bring gas to market interconnector projects, or a TSO with a large asset base, interconnector projects will struggle. Therefore, it is probably essential that the State or the EU stands behind them to provide financial support and some leadership.

CESEC – breaking the logjam?

Into this space of conundrum solving – interconnectors are needed to build a regional market and improve security of supply, but how to kick-start the process? the European Commission developed the CESEC Initiative.[53]

It started in December 2014 when Maros Sefcovic, Vice-President of the European Commission for Energy Union, and many SE European regional representatives agreed a 'high level working group' should be set up to promote and encourage interconnector projects in central and southern Europe; CESEC was born. It first met in Sofia in February 2015, and identified a short-list of projects from the long-list in the PCI. The main kick-off was an endorsement and ceremonial signing at Dubrovnik in July 2015, when all members signed off on the priority projects selected in front of the hosting Croatian President Kolinda Grabar-Kitarovic. Ministerial delegations from Austria, Bulgaria, Croatia, Greece, Hungary, Italy, Romania, Slovenia, Slovakia, Albania, Bosnia & Herzegovina, Moldova, FYROM, Serbia and Ukraine attended, as well as a Commission contingent and some industry representatives.[54] This detail is important, as it showed a widespread understanding of the problem of getting the interconnections built, and was an admission that little had been achieved so far.

[53] CESEC - Central Europe and Southern Europe Gas Connectivity.
[54] This author was present, representing BP.

Nine projects were selected, divided into 6 priority and 3 conditional priority.

	Priority projects	**Commentary – based on the Action Plan agreed at Dubrovnik in July 2015**
0	TAP	Already sanctioned, so given the number '0'. A key piece of supply diversification infrastructure, carrying Azeri, and potentially in the future also Central Asian gas, westwards into southern Europe.
1	IGB (Interconnector Greece-Bulgaria)	A key route for moving gas from TAP and the new Greece LNG terminal (see project 9 below) northwards.
2	IBS (IC Bulgaria-Serbia)	Crucial for supply diversification and security of supply for Serbia. But necessary if *Gastrans* is built?
3	Bulgaria system reinforcement	Technically, the size and capacity of the Bulgaria domestic system is 1835 km (basically forming a ring within Bulgaria), capacity 7.4 bcm, max operating pressure 54 bar (BTG website). This capacity would be insufficient for handling transit gas, and the system anyhow needs upgrading. Not apparently considered at the time (in 2015) was the potential impact of South Stream (now Turk Stream) through emptying the Trans Balkan Pipeline on SE European regional gas flows.
4	Romania system reinforcement	General system upgrading and expansion to ensure existing and planned bi-direction interconnectors with Hungary, Bulgaria, Moldova and Ukraine can be integrated into the regional market.
5	Croatia LNG (Krk)	Aim of access to supply from the global LNG market, thereby diversifying supply and enhancing security of supply for Croatia and the broader CESEC region.
6	LNG flow Croatia to Hungary	Croatia LNG will provide volume beyond the capacity of the Croatia market to absorb. Croatia current consumption is 2.6 bcm/year. The size of the FSRU 1st Phase is also 2.6 bcm/year.
	Conditional priority projects	
7	Romania offshore	Connect prospective offshore gas developments to the Romanian grid.
8	Croatia-Serbia IC	In the event of unsatisfactory progress on IBS, then this becomes necessary, targeting supply from Croatia LNG.
9	Greece LNG	Location not specified, but this would be a 2nd terminal after the expanded existing Revythoussa. Alexandroupolis LNG is the frontrunner.

The list looked to be a comprehensive solution for promoting regional market interconnectivity by connecting up all the region's markets while simultaneously creating supply diversity. Supply would come in the near and medium-term from the Southern Corridor and LNG, or potentially from the Eastern Mediterranean or elsewhere.

Surprisingly, one project did not make the cut – the Ionian Adriatic Pipeline (IAP) from Albania to Croatia via Montenegro. This was surprising as the EU (via the West Balkan Investment Framework, WBIF) was supporting a detailed feasibility study of IAP. In a moment of theatre at Dubrovnik, the Albanian representative threatened not to sign the Action Plan unless IAP was included, and a rapid form of words had to be found quickly to satisfy him. What was not discussed was the cost of the programme, and at various subsequent working groups the EC was usually unwilling to talk about capex required, but occasionally did admit to a $4billion estimate.

Map 2: SE Europe – interconnector pipeline

Source: OIES

CESEC performance

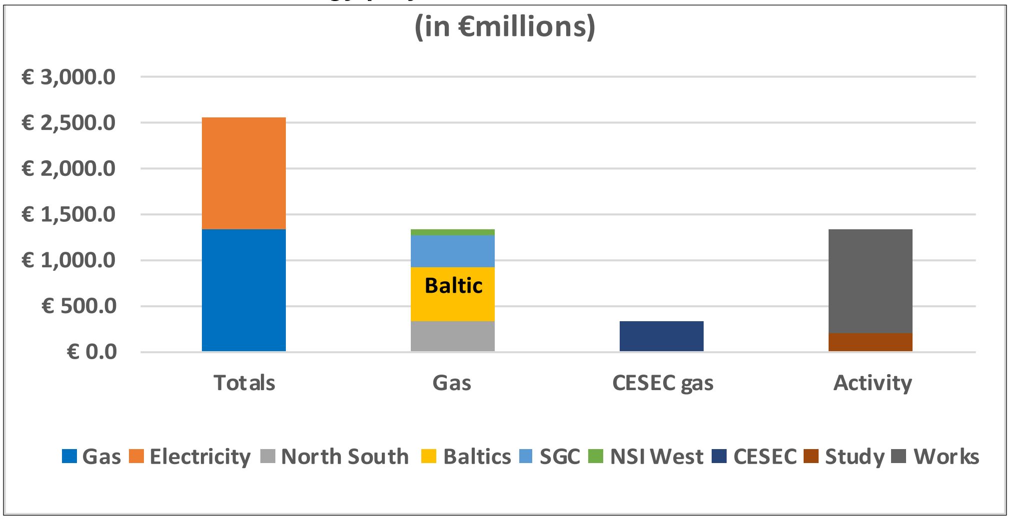
CESEC, conceived at the end of 2014, has been active for the whole life of the Junker Commission, which comes to the end of its term in October 2019. What has it achieved? What does its end-of-term report look like? On one tangible measure - what has been built - the end-of-term report is very poor: nothing has been built. The Bulgaria-Romania interconnector was completed, in 2016, but this was under way beforehand and was not on the project list.

One problem has always been finance, and whether financial assistance from various support funds can be mobilised. The main support funding available from the various EU pots is the Connecting Europe Facility (CEF); there is also the European Structural and Investment Fund (ESIF), the Instrument for Pre-Accession, the European Neighbourhood and Partnership Instrument.

Taking just CEF, over the 5-year period 2014-2018, funding can be broken down as follows:[55]

- €2.6 billion was allocated to the electricity and gas sectors.
- Exactly 50% of this went to gas - €1.3 billion. 47% went to electricity interconnections, and the remaining 3% to smart grids.
- Of the €1.3 billion to gas, some 14% or €190 million was directed at supporting a large number of feasibility and other project support studies.
- Splitting gas down geographically is the most interesting feature. The Baltic region (including Poland's Baltic-facing projects) received nearly half the total – 45% or €600 million. The big allocations here were to the Poland-Lithuania interconnector (€295 million) and the Finland-Estonia interconnector (€187 million).
- CESEC specific support was just €320 million, or 24% of the total allocation to gas projects.
- Within this €320 million, there were basically just two big allocations:
- In 2015, Romania (Transgaz TSO) secured €179 million for BRUA related work
- In 2016, Croatia LNG secured €101 million for the Krk terminal work, and in 2017 a further €16 million for associated onshore pipeline work.
- The remaining €26 million went to support studies, for example: LNG Greece; Croatia LNG's onward pipeline transportation; Bulgaria's Chiren storage.
- To be strictly fair, the Greece-Bulgaria interconnector quite late in the day in mid-2018 did receive €110 million from the EIB.[56]

Figure 3: CEF assistance for energy projects 2014 – 2018



Source: EU, annual CEF Energy reports

There was some other funding, for instance from the West Balkan Investment Framework for the feasibility studies for IAP, Croatia LNG, the Albania Gas Master Plan, for example, but these were relatively small (a few € millions) and don't affect the overall story that the Baltics have done relatively well, and SE Europe relatively less well. Despite CESEC, therefore, funding seems preferentially to

[55] Numbers aggregated from the annual 'List of actions selected for receiving financial assistance under CEF-Energy', in http://ec.europa.eu/energy.

[56] http://www.eib.org/en/projects/pipelines/pipeline/20140376

have gone to the Baltic area. From all this, several unanswered questions emerge. How did the Baltic region manage to secure almost half the CEF gas allocations and why has CESEC not managed to mobilise relatively more funding?

It is possible that there is some concern in some quarters about the amounts dedicated to gas infrastructure funding generally and how it has been deployed. For instance, a question was asked in the European Parliament by Cornelia Ernst in July 2018 specifically on this subject. Commissioner for Energy Arias Canete in his written answer confirmed the amounts awarded under various schemes, and that the main source is CEF, but he ducked that part of the question on the regional distribution of funding allocations.[57] He wrote:

- Under the Connecting Europe Facility (CEF), €1.2 billion had been awarded over 2014-20 to gas transmission projects. But of this, €210.2 million had so far been paid. (Note, his figure of €1.2 billion broadly confirms the analysis above).
- A further €900 million had been allocated over 2014-2020 to eight Member States in less developed regions under the European Structural & Investment Funds (ESIF) for investments in gas infrastructures. The eight were Bulgaria, Romania, Greece, Czech, Poland, Latvia, Lithuania, Portugal.

In his answer, he added that the Commission expects all EU gas markets to be well connected and shock resilient by 2022-25. Therefore, financing electricity projects for integration of renewable energy networks will come to dominate PCI funding in the future.

The conclusion on CESEC could be that, despite short-listing projects, it has not managed to get anything built so far. However, a more rounded appraisal is that much has been accomplished on the software side, on getting the regulatory regime in place, on getting the interconnection agreements agreed between countries, and on building momentum for the idea. Therefore, the achievement of CESEC has been to inject process, some direction, some sense of region and the importance of interconnectivity. It has brought the TSOs together, got them to talk, got them to prepare presentations at its workshops, generally pushed them along. In that respect, the next Commission might get the credit for the welding.

The Three Seas Initiative – a larger framework for CESEC

The ‘Three Seas Initiative’ is a political platform of 12 Member States connected in an arc bounded by the Baltic, Adriatic and Black Seas. The aim of the initiative is to boost transport, energy and digital connectivity, from Estonia on the Baltic to Bulgaria on the Black Sea. CEF is a key funding instrument, and in the next financial cycle (2021-27) it will have a proposed €42.3 billion budget.[58] On energy, it has 3 big components. The Baltic Energy Market Interconnection Plan aims to achieve an integrated and open electricity and gas market, underpinned by several cross border physical links, such as the

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[57] Written question E-004046/2018 by Cornelia Ernst, substitute member of the EP’s Committee on Industry, Research and Energy, to the Commission. The Canete answer on 24th Sept 2018 is in http://www.europarl.europa.eu/doceo/document/E-8-2018-004046-ASW_EN.html He gave no details on any regional or project breakdowns.

[58] Three Seas Initiative, brochure prepared for Summit meeting, Bucharest, 17-18th September 2018. The overall funding from the EU is a confusion of several pots. The Cohesion Fund of €63.4billion over 2014-20 is available to Bulgaria, Croatia, Cyprus, Czech, Estonia, Latvia, Lithuania, Malta, Greece, Hungary, Poland, Portugal, Romania, Slovakia, Slovenia. https://ec.europa.eu/regional_policy/en/funding/cohesion-fund/ “The CF will support infrastructure projects under the CEF”. The CEF has €24.05 billion over 2014-20 covering transport, energy and digital connections. https://ec.europa.eu/transport/themes/infrastructure/ten-t-guidelines/project-funding/cef_en Of this €24.05 billion, €11.305 billion will be available specifically for projects located within the territories of Member States that are eligible for the Cohesion Fund. It is not transparently obvious whether allocations in some of these pots is overlapping.

Poland-Lithuania interconnector which has already received €266 million. Secondly, Phase 1 of the BRUA interconnector to connect Bulgaria to Austria via Romania and Hungary has received €179 million from CEF and €100 million from EIB. Lastly, there is CESEC, where €124 million has gone already to Krk LNG and the evacuation system towards Hungary. Note, the Three Seas Initiative brochure talks generally of the budget for 2021-27 but ducks how this is to be allocated, and sums mentioned in it have already been allocated under previous funding.

However, Three Seas funding follows the pattern detected by the CEF analysis above. Taking the European Regional Development Fund & Cohesion Fund, Three Seas shows total allocations for its 12 member States over 2014-20 was €155 billion, of which €56 billion went to transport, energy and digital connectivity. But, when the numbers are broken down on a per capita basis, then the 4 CESEC Member States in these 12 got substantially less that the 4 Baltic states (the 3 Baltics plus Poland): they received just 60% of the Baltics allocations. The Baltic-4 got €1700 per capita, while the CESEC-4 of Bulgaria, Romania, Croatia and Slovenia received just €1000 per capita. There could be a hint of institutional bias here.

VI. Endgame – an interconnected, resilient and functioning market in SE Europe by 2025?

Is Canete's remark that the whole EU gas market will be well connected and shock resistant by 2025 plausibly correct? The CESEC priority projects would probably achieve this for SE Europe if they can be built by then, but the track record is one of very slow delivery. One question remains; how do you assess interconnectivity? Can it be measured, when is there sufficient interconnectivity to support market maturity? One way could be through price convergence; narrow price differentials reflect good physical and regulatory interconnectivity. ACER does assess this in its annual market monitoring report, and it shows narrow differentials in NW Europe and wide differentials in SE Europe. [59]

Activity in 2019 gives cautious optimism that it is feasible, that there is enough going on: some projects are happening, trading is beginning to take advantage of new opportunities. For instance, Bulgaria has imported LNG for the first time, FID has been taken on Croatia LNG, and Turk Stream Line 2 onshore has momentum. Assuming it is built, then there will be some irony that Russia has contributed significantly to regional connectivity. However, much of this will require more than wafting the regulatory wand; it will require material ongoing central financial support to deliver the pipeline and regas projects.

Future supply – LNG into SE Europe?

In April 2019 Bulgargaz issued a tender, won by DEPA, for 140 mcm, and the LNG supplied reportedly came from Sonatrach. In June 2019, Bulgargaz contracted a further 140 mcm (90 million contracted from Kolmar and supplied by Cheniere, and 50 million by BP). Thus total LNG contracted in 1H2019 was 0.28 bcm, approaching 10% of Bulgaria's current annual demand. The LNG will come into Greece's Revithoussa terminal, and then be delivered through the existing transit line from Bulgaria to Greece operating in reverse flow. During the 2009 supply crisis, there had been a small flow from Greece into Bulgaria, but this was a one-off during an emergency and was achieved because the Greek system works at higher pressure than the Bulgarian one. The interconnection agreement with Greece was made in 2016, and technical capacity in the line being offered in 2019 is 4,100 mcm/day, or 1.5 bcm/year.[60] The incentive for the imports reportedly was that the price of spot LNG had moved below oil-indexed Russian gas. Even if there were other factors too, it represents a demonstration of alternative supply entering the region, which is now possible both from the interconnection agreement and the application of, or removal of obstructionism from the May 2018 DG Comp-Gazprom anti-trust

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[59] ACER presentation by Dennis Hesseling 'The EU gas market in context' at the Energy Democracy Summit, Pula, Croatia, 10th April 2019; ACER Market monitoring Report 2017, published October 2018 - see especially para 152.

[60] Bulgartransgaz TYNDP 2019-28, pages 15, 21

settlement. One market question now is that with the small Bulgaria-Romania interconnector built in 2016, if commercial terms are attractive enough, are there any barriers preventing Romania also taking some LNG?

In Croatia, after many years of project change of scope (onshore small 3 bcm/year, on-shore large 6 bcm/year), management change-outs and political interference, Croatia LNG took its FID in January 2019. An FRSU has been contracted from Golar for delivery around 4Q2020, which would mean commercial start-up in 1Q2021. The location is Krk island's sheltered bay, close to the long-existing oil terminal there. The ship will be the *Golar Viking*, built in 2005, costing €160 million delivered and giving a first-phase capacity of 2.6 bcm/year. With jetty and on-shore pipeline to the Plinacro system at €58.4 million, total capex is €233.6. FID was based on binding open season commitments of 0.52 bcm/year.[61] Financing is from a €101.4 EU CEF grant, a Croatia State grant of €100 million and €32.2 million from shareholders. *Golar Viking* has storage of 140,000 m^3, and regas capacity of 300,000 m^3/hour, giving an annual capacity of 2.6 bcm – which is in line with the technical capacity of Croatia's transmission system. However, this level would almost equate to Croatia's entire annual demand, so high utilisation would entail exports beyond Croatia into Hungary or Slovenia (or even into IAP, if IAP is built).

A second Greek terminal project, Alexandroupolis LNG, was looking to take FID in mid-2019 (that date has now passed) and start-up was scheduled for 4Q2020, but that has now slipped back a year as the delivery of the 5.5 bcm/year capacity FSRU vessel is not now expected until 1H2021. The project is promoted by Gastrade SA, a Greek utility. Target markets include Bulgaria, gas being delivered via IGB, scheduled to be built by end-2020, and also possibly to Ukraine through the soon-to-be empty Trans Balkan Pipeline.[62] Capex is estimated at €382 million, financed by a mix of equity, debt and grants, and it is on the EU's PCI list, so is eligible for CEF money.[63]

On pipelines, the Greece-Bulgaria interconnector (IGB) is making belated progress. In May 2019 there was a ground-breaking ceremony, and it now expects to be operational by the end of 2020.[64] Finance for the €240 million planned capex is coming from the EIB (€110 million with sovereign guarantee), the European Structural & Investment Funds (€39 million), shareholders (€46 million) and the European Energy Programme for Reconstruction EEPR (€45 million). In Romania, the first phase of BRUA is under construction, financed partly by EIB and EBRD contributions.[65]

In terms of regional policy support, while Romania is creating uncertainty, Bulgaria appears to have more direction. Bulgaria Energy Holding (BEH – the owner of Bulgargaz, Bulgartransgaz etc) has said our "priority is building gas interconnections with Romania, Greece, Serbia & Turkey. This gives opportunity to get gas from several sources, in turn improving competition. New gas interconnectors will increase entry capacity from Greece & Turkey and provide access to LNG from terminals in those countries".[66]

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[61] Details from Hrvatska LNG website, procurement section

[62] Alexandroupolis LNG presentation by Gastrade at CESEC working group in Brussels, February 2019 https://ec.europa.eu/energy/sites/ener/files/documents/gastrade_alexandroupolis_lng.pdf and https://ec.europa.eu/energy/en/topics/infrastructure/high-level-groups/central-and-south-eastern-europe-energy-connectivity/Past-and-upcoming-CESEC-meetings

[63] http://www.gastrade.gr/en/the-company/news-press-releases/the-first-phase-of-the-market-test-for-the-floating-lng-terminal-in-alexandroupolis-was-successfully-completed.aspx

[64] https://www.icgb.eu/the-executive-officers-of-icgb-gave-start-of-the-construction-activities-for-the-gas-interconnector-greece-bulgaria. Also Bulgartransgaz TYNDP 2019-2028, pp 24-25

[65] Transgaz financial statement year-ended 2018, note 16 on its long-term borrowings.

[66] BEH consolidated management report for year-ended December 2017 page 39. Other projects include Gas Hub Balkan, Eastring op cit page 39, and general modernisation of the Bulgarian system.

VII. Main conclusions

The key conclusions from the analysis above are:

- There is sufficient interconnectivity project momentum to deliver the SE European part of much of the Canete vision of European gas by 2025. However, severe challenges remain, in particular on financing. Whether there can be a fully functioning market by then is doubtful, but certainly the completion of several of the CESEC priority projects will create one of the essential preconditions for a sustainable pricing hub – good connectivity to enable supply diversity and the transfer of price signals from market to market.
- Interconnectivity is crucial for market building and security of supply. The region has been very slow to build it; Canete's 2025 vision could have been realised earlier. EU policy initiatives have not produced pipeline hardware; projects have not been completed, and project support funds seem to have been more directed to northern Europe. However, possibly what has been created by CESEC over 2015-19 is a platform for the next Commission to encourage tangible interconnectivity hardware.
- Interconnectivity is critical for a hub, notably lacking in this part of the EU, where most gas is still priced on an oil-related basis. Bulgaria has hub aspirations, but if anyone can create a functioning hub during the late-2020s then it is probably a well-connected Romania.
- Demand growth will be modest at around 2%/year and is overall more a recovery story than a growth story. There could be an upside from coal displacement if policy initiatives are put in place, but there is no evidence of such moves at present. Clearly, tackling coal will come with high social costs as well as the economic cost of exchanging domestic coal for imported gas.
- The Black Sea offshore would turn Romania from slight deficit to surplus. Volume is uncertain, but Romania could be a net exporter of 4-5 bcm/year by the mid-2020s, roughly sufficient to meet expected regional demand growth. At present, Romania is not actively stepping up to grasp the regional gas leadership role it could have based on the size of its market and its production: instead, it is frightening upstream investors with new market-controlling legislation. If the offshore does work, then surpluses will further drive interconnectivity as these will have to be moved to neighbouring markets.
- The region will retain a transit function, although its character will change radically, and it could become larger. The Trans Balkan Pipeline (TBP) system is likely to become redundant as Russia increases volumes through Turk Stream, but moving Turk Stream gas through SE Europe will require new capacity and this is planned through Bulgaria and Serbia. Additionally, new gas through the Southern Corridor (for instance TAP to Italy) will enter the region soon.
- Requirement for Ukraine transit will drop by 19 bcm in 2020 as Turk Stream is commissioned.

There is enough going on throughout the SE Europe gas chain to suggest that its importance to Europe – building the Energy Union, transit role, developing the Black Sea offshore, delivering Brussels' infrastructure policy, the EU-Russia relationship – can increase as it interconnects itself and connects with neighbouring regions. Particular signposts for progress would include FID on Neptun, Croatia's LNG terminal, the commissioning of the IGB interconnector and policy initiatives to address lignite consumption.

Appendix 1 – Selected pipeline projects in SE Europe[67]

1. Greece-Bulgaria interconnector (IGB)

A 182 km pipeline linking Komotini in Greece with Stara Zagora in Bulgaria (151 km in Bulgaria, 31 km in Greece), and connecting the Southern Corridor's TAP with the Bulgarian domestic ring system. A 32-inch pipeline, with initial capacity of 3 bcm/year, expandable to 5 bcm/year through investment in compressors. Ownership is a JV company 50% Bulgaria Energy Holding (BEH) and 50% Poseidon, which in turn is 50% DEPA and 50% Edison.[68]

Capex forecast is €240 million, and most of the financing is now in place: €110 million EIB long-term loan finance; €45 million EEPR grant and €39 million from the EU Structural investment fund. Remainder from shareholder equity and short-term financing.

Construction is scheduled to start to start in the summer 2019, and commissioning at the end of 2020. As of July 2019, all licenses and permits have been granted, making this schedule look realistic.

On regulatory aspects, it does have an exemption reserving about half its initial capacity, mainly for the 1 bcm/year Bulgargaz contract for Shah Deniz gas.

2. Bulgaria-Serbia interconnector (IBS)

A 170 km pipeline. 61 km in Bulgaria, 108 km in Serbia. A 28-inch pipeline. Capex in Serbia is €85 million. Planned initial capacity is 1.8 bcm/year, expandable to 4.5 bcm/year, and it will be bi-directional. Construction is scheduled to start in October 2020, and commissioning in May 2022. The major question now is whether it is required. Assuming Turk Stream Line 2 into Bulgaria & Serbia happens and the regulatory issues around third party access are solved (Energy Community Secretariat requesting 30% of capacity of almost 14 bcm is removed from the exclusive use of Gazprom & Srbijagas to be available to the general market), then this interconnector looks unnecessary. [69]

3. BRUA - Romania

BRUA (Bulgaria-Romania-Hungary-Austria) when complete will create a transnational system linking Bulgaria with Austria, with work centred on Romania. Basically, it serves three purposes: modernisation and enhancement of a large section of the Romanian system; provision of more capacity at the Romania-Hungarian border; the evacuation of Black Sea gas.[70]

Phase 1 is a new 32-inch pipeline across southern Romania from Podisor to Recas: 479 km, 63 bar pressure, and 3 compressor stations at Podisor, Bibesti and Jupa. Capex is €479 million (ironically precisely €1 million/km) including three compressors. Construction is in progress, and six compressors for the three stations were delivered in 4Q18.

Once complete by 2022 with some short pipeline sections and additional work on compressors, **Phase 2** will result in a 4.4 bcm/year bi-directional capacity at the Romania-Hungary border, and enable Romanian Black Sea gas to be moved into Central Europe.

[67] Details of all projects are taken mostly from project update presentations made at CESEC Plenary meeting, Brussels, Feb 2019, in https://ec.europa.eu/energy/en/topics/infrastructure/high-level-groups/central-and-south-eastern-europe-energy-connectivity/Past-and-upcoming-CESEC-meetings

[68] https://www.icgb.eu/about/igb_project

[69] At the ECS annual Gas Forum in Ljubljana 24th-25th Sept 2019, one Serbian delegate said "it's dead".

[70] See John Roberts, Three Pipelines & Three Seas: BRUA, TAP, the IAP and gasification in Southeast Europe, Atlantic Council September 2018, page 4.

4. Ionian Adriatic Pipeline (IAP)

The concept is a 550 km 32-inch pipeline from TAP in Albania to connect with the Croatian system in southern Croatia, the pipeline going through Montenegro. Capacity would be around 5 bcm/year. Intended flow would be south-north, although it would be bi-directional. A branch could go to Bosnia-Herzegovina and provide supply generally for the gasification of the western Balkans. A feasibility study funded by the West Balkan Investment Framework in 2014 put capex at around €620 million.

The project has been advanced at the same time as Croatia LNG, but two issues have never been clear despite the feasibility studies:

- How would IAP work with Croatia LNG; would they be competitive or complementary? Combined capacity of 7.5 bcm/year would be far in excess of the absorption capability of Albania, Montenegro (neither has a gas market) and Croatia. Indeed, IAP alone would need to put gas outside the immediate IAP market envelope.
- Therefore, IAP would imply the need for interconnector capacity with Slovenia and/or Hungary, turning it into what it really is, which is a regional transit system. Therefore, the capex estimate from the feasibility study of IAP in isolation is clearly far too low.