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Let’s not exaggerate:

Southern Gas Corridor prospects to 2030

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Simon Pirani, July 2018

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A new round of political activity to promote the Southern Gas Corridor from the Caspian to Europe has begun, with a meeting in February of European energy ministers and supplier nation officials, and the opening ceremony in June for the Trans Anatolian Pipeline (TANAP) across Turkey. The first, and so far only, substantial source of supply for the corridor, the Shah Deniz II project in Azerbaijan, started producing gas in June, and will ramp up to its peak output of 16 bcm/year by 2021-22. This will mean that Europe will receive around 10 bcm, no more than 2 per cent of its overall demand, via the southern corridor;[1] and Azerbaijani gas will be more significant in south-eastern Europe and in Turkey than in Europe's major markets. While political leaders continue to paint the corridor's prospects after 2021-22 in very bright colours, the market dynamics – in the Caspian region itself, in the Caucasus and Turkey, and in Europe – are less promising. The commercial conditions for the southern corridor's success have deteriorated as political support for it has grown. This paper argues that, up to 2030, the corridor will most likely remain an insubstantial contributor to Europe's gas balance. It considers the potential sources of supply for the southern corridor (Azerbaijan, Turkmenistan, and others including Iran, Kurdistan, and the East Mediterranean); demand and transport issues in the Caucasus and Turkey that will influence the corridor's future development; and the conditions under which southern corridor gas will compete with other supply in the European market.

Map: the Southern Gas Corridor, July 2018

Key. New pipelines to south-eastern Europe: black (completed) and black broken lines (projected). Other gas pipelines: red (large diameter) and blue (other).
Source: OIES (adapted from IEA web site).

[1] European gas demand as measured by my colleague Anouk Honore (namely OECD Europe plus six small markets) was 548 bcm in 2017. The European total is about 500 bcm if Turkey is excluded. Demand is expected to stay level, or register limited growth, in the next few years. Anouk Honore, *Natural gas demand in Europe in 2017 and short-term expectations* (Oxford: Oxford Energy Insight 35, 2017); Anouk Honore, "Natural gas demand in Europe", *Oxford Energy Forum*, April 2017, pp. 5-8

Political drivers versus economic difficulties

The Fourth Ministerial Meeting of the Southern Gas Corridor Advisory Council, in Baku in February 2018, declared its aim "to secure reliable and sustainable supply of gas from the Republic of Azerbaijan to Georgia, the Republic of Turkey and further to European countries".[2] Beyond Azerbaijan it welcomed "the interest of potential additional suppliers of natural gas from the Caspian Basin, Central Asia, the Middle East, the Eastern Mediterranean Basin and the Black Sea". Such suppliers could use the southern corridor to "further diversify natural gas supplies to Europe". The meeting's communique also promoted "the expansion of the Southern Gas Corridor to further markets", including Energy Community countries on Europe's south-east borders, and re-affirmed EU interest in the proposed Greece-Bulgaria interconnector, and "bi-directional connection between the gas systems of Turkey and Bulgaria, including but not limited to the potential offered by bi-directional connection between Bulgaria and Romania". It also referred to the Ionian Adriatic pipeline, although it is not denoted as an EU Project of Common Interest.

After the meeting, political commentary suggested that Turkmenistan was ready to engage with the project actively. Parviz Shahbazov, Azerbaijan's energy minister, said the prospect of Turkmenistan joining the project was "quite realistic", and Maros Sefcovic, European Commission vice president for energy, confirmed that discussions were continuing with the Turkmen government.[3] Some government officials have specifically rejected suggestions that changing commercial conditions for the Southern Gas Corridor have made its expansion more difficult. John McCarrick of the US State Department's Bureau of Energy Resources said in June: "Even with the rise of LNG on the markets today, I think you can still make a business case for Southern Gas Corridor gas."[4]

It is worth reviewing political efforts to establish the southern gas corridor, as follows. The vision of a pipeline system bringing gas across the Caspian, in the first place from Turkmenistan, and westwards through the Caucasus and Turkey, was first advanced in the early 1990s by the US and European governments. It was hoped that the successful expansion of oil exports from Azerbaijan – with the "deal of the century" on Azeri-Chirag-Guneshli production (production sharing agreement (PSA) signed 1994), and construction of the Baku-Tbilisi-Ceyhan pipeline (agreed 1998, commissioned in 2006) – could be built on. The start-up of gas exports – to Turkey, but not to Europe – followed, in a relatively short time scale by the standards of major projects, from the Shah Deniz field in Azerbaijan. In 1996, an international consortium led by BP signed an exploration, development and production sharing agreement for the Shah Deniz area. The gas field was discovered in 1999, gas sales agreements were signed with Turkey in 2001, the South Caucasus pipeline to Turkey was built and production began in 2006. But US and European hopes of expanding this corridor by bringing gas across the Caspian were not realised. There were expressions of political intent, such as a framework agreement on Trans Caspian pipeline construction (1999) between the presidents of Turkmenistan, Azerbaijan, Georgia, and Turkey. However, political opposition from Russia and Iran, and the legal problems created by the unresolved status of the Caspian Sea, and territorial water border disputes, stymied progress.[5]

Political support in Brussels for the "southern corridor" generally, and for the Trans Caspian pipeline specifically, grew again in the mid 2000s. It intensified further after the "gas wars" between Russia and Ukraine in 2006 and 2009, which amplified concerns about the level of EU dependence on Russian gas imports and Ukrainian transit. In 2004, the European Commission (EC) launched the Baku Initiative, a

[2] *Joint Declaration by the Fourth Ministerial Meeting of the Southern Gas Advisory Council*, 15 February 2018 (draft, Brussels, 29 January 2018)
[3] "Turkmenistan joining Southern Gas Corridor is 'quite realistic'", *Caspian News*, 5 March 2018
[4] "NGW interview: US State Dept's John McCarrick", *Natural Gas World*, 11 June 2018
[5] "Trans Caspian gas pipeline accord signed", RFE/RL Newsline 3:226, 19 November 1999; Tatiana Mitrova, Simon Pirani and Jonathan Stern, "Russia, the CIS and Europe: Gas Trade and Transit", in Pirani (ed.), *Russian and CIS Gas Markets and their Impact on Europe*, pp. 395-441, here pp. 403-444

policy discussion with Caspian states, and held a ministerial conference on energy cooperation. In 2006, an EC energy policy document foresaw Black Sea and Caspian countries working with the EU to "boost new [energy] supplies from central Asia to the EU", and "cooperation on pipeline projects such as Nabucco [an early iteration of the southern corridor] and further projects from the Caspian basin". In 2011, a detailed communique on external energy policy described the Southern Gas Corridor as a "key infrastructure priority" and "a supply route for roughly 10-20 per cent of EU estimated gas demand by 2020".[6]

Over the last decade, the more that political support for a southern corridor has risen, the more the commercial conditions for it have deteriorated. Firstly, a major non-Russian gas export corridor from Turkmenistan was opened up – to China, rather than to Europe. In 2006 Turkmenistan reached a framework agreement with China on construction of a gas pipeline with an initial capacity of 30 bcm/year; in 2007 a PSA with CNPC to develop the Bagtyyarlyk area followed. Turkmen gas exports to China started in 2010, and, notwithstanding a sharp fall in the volume of Turkmen exports to and through Russia, caused Turkmenistan's government to lose what interest it had had in discussions about the Trans Caspian option. Secondly, from 2006, Gazprom of Russia accelerated investment in the Yamal peninsula development, ensuring that by the 2010s very large volumes of Russian gas would be available for export to Europe at relatively low cost. The economic crisis of 2008-09 then reduced European demand; much lower gas prices in Europe in 2009-10 raised questions about the economics of exports from the Caspian, and how they could compete with imports from Russia and elsewhere. These questions, and regulatory issues, were among the causes of the failure of the EC's Caspian Development Corporation (CDC), set up in 2009 with a view to becoming a single buyer for Turkmen gas for Europe, which effectively suspended its activity in 2012.[7] Thirdly, Russia's determination to diversify gas transit away from Ukraine complicated the problems facing southern corridor pipeline projects. Gazprom, having cancelled its proposed South Stream pipeline across the Black Sea in 2014, due to political and regulatory problems in the EU, then agreed with Turkey on the Turk Stream project, crossing the Black Sea to western Turkey rather than Bulgaria. Turk Stream 2, the second phase of the project, is still likely to be commissioned in the early 2020s, and puts competitive pressure on the expansion of TANAP.

The outcome of all these changes is that the southern corridor is being initiated in a far more modest form than anticipated, aiming to provide about 2 per cent of European gas demand in 2020, rather than the 10-20 per cent originally envisaged. The final investment decision (FID) on the second phase of production at Shah Deniz – from which the first Caspian gas to Europe will flow in 2019 – was taken in 2013. Soon afterwards, European gas prices fell again, casting a shadow over subsequent export-focused projects in Azerbaijan. Strong strategic support from Azerbaijan and Turkey has ensured that two parts of the southern corridor – the South Caucasus Pipeline expansion and the construction of TANAP – have gone ahead. At the time of writing, an FID has been taken on the third part, the Trans Adriatic Pipeline (TAP), but it has been delayed by political opposition, and related regulatory problems, in Italy. The delay has been prolonged following the Italian elections in March, which have brought to office a coalition government which includes committed opponents of the project.

The prospects for production and export growth in the 2020s are now discussed, for Azerbaijan, Turkmenistan, and other potential suppliers.

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[6] European Commission, *External energy relations – from principles to action* COM (2006) 590, 12 October 2006; European Commission, *On security of energy supply and international cooperation – 'The EU Energy Policy: Engaging with partners beyond our borders'* COM (2011) 539, 7 September 2011, p. 5.

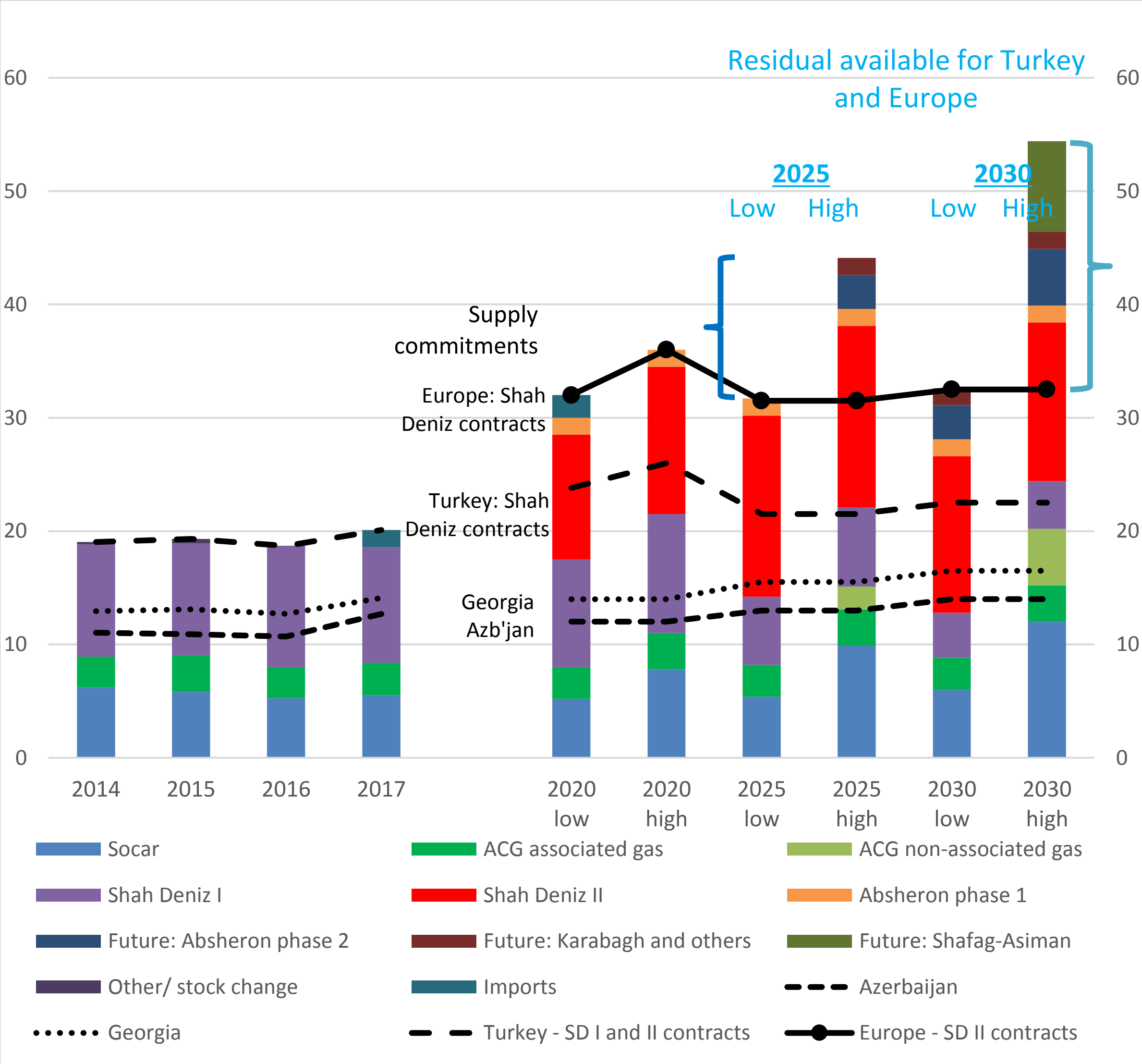
[7] See: Simon Pirani, *Central Asian and Caspian Gas Production and the Constraints on Export* (OIES, NG69, December 2012)

Azerbaijan supply and export outlook

The three most important factors that will determine the level of Azerbaijani gas exports to the EU up to 2030 are: 1. The level of output, and, specifically, the pace at which new Caspian fields can be developed; 2. The volume of gas required in Azerbaijan's domestic market and in Georgia; 3. The potential comparative advantages of Turkey over EU countries as a destination for Azerbaijani gas. These are discussed in turn.

In this section, an argument is presented that, in addition to Azerbaijan's commitments to the domestic market and Georgia, and contracts already signed for gas from the Shah Deniz field, the likely volumes available to share between Turkey and Europe will be zero in 2020, between 0.2 and 12.6 bcm in 2025 and between 0.1 bcm and 21.9 bcm in 2030. Illustrative projections of the levels of production, and of supply commitments, are shown in Figure 1. The numbers on which these are based are presented in Table 3 below, (page 10).

Figure 1: Azerbaijan gas production, and supply commitments: illustrative projections, bcm/year



Source: Author's estimates

Output and field development

Azerbaijan's gas output in the 2020s will comprise (i) production from Shah Deniz stages I and II; (ii) production from PSAs and prospective PSAs; and (iii) production from fields wholly or mainly owned by Socar, the national oil and gas company. The outlook for production from all three categories was described in detail in a paper by the author, published in 2016.[8] Current and future possible projects are listed here in Table 1; there then follows a summary description, with information about developments in the last two years.

Table 1: Azerbaijani gas projects

	Owner or operator	**Plateau output (bcm/yr)**	**Status**
Currently producing			
Shah Deniz I	Consortium led by BP	10	In production since 2007
ACG associated gas	Consortium led by BP	3	In production since 2005. Note that the level of ACG associated gas produced is related to the level of gas required for re-injection to increase oil production, which fluctuates around 10-13 bcm/yr.
Shallow Water Guneshli	Socar	3.5	In production
Other small fields	Socar	2.5	In production
New/ in development			
Shah Deniz II	Consortium led by BP	16	First gas produced June 2018; peak output 2021-22
ACG non-associated gas	Consortium led by BP	5	Under negotiation
Absheron phase 1	Consortium led by Total	1.5	Production expected 2020
Absheron phase 2	Consortium led by Total	5	Under negotiation
Karabagh, Ashrafi, Dan Ulduzu	Statoil Azerbaijan and Socar	1.5	Risk service agreement signed May 2018
Umid	Socar	1.5	Production expected during 2020s
Babek	Socar, Nobel Upstream	3 - 5	Exploration not started
Shafag-Asiman	BP	8	PSA signed 2010; exploration not started
D230 block	BP and Socar	n/a	MoU on exploration signed May 2018

Source: company announcements, media reports

Shah Deniz. Both phases of production at the Shah Deniz field are operated by an international consortium headed by BP. Shah Deniz I's plateau production, originally expected to be 8.5-9.0 bcm/year, was reached in 2013 and has been at 9.8-9.9 bcm/year since then. From 2007 sales were made to Botas of Turkey under a contract covering 6.6 bcm/year of these volumes; this expires in 2021. First-phase production is expected to go into natural decline in 2024, reaching 4.1-4.2 bcm in 2030 and ceasing output before 2035. First gas began to be produced from Phase II in June; the project will ramp up to peak output of 16 bcm by 2022; it is expected to go into natural decline in 2030, falling to about 6

[8] Simon Pirani, *Azerbaijan's Gas Supply Squeeze and the consequences for the southern corridor* (Oxford: OIES Paper NG 110, 2016)

bcm in 2035. Gas sales of 6 bcm in Turkey, 1 bcm in Greece, 1 bcm in Bulgaria, and 8 bcm in Italy are covered by 25-year long term contracts.[9]

Other PSAs and prospective PSAs. Apart from Shah Deniz, there is one Azerbaijani gas field in development: the Absheron project, covered by a PSA between the government and a consortium of Total (operator, 40 per cent), Socar (40 per cent) and Engie (20 per cent). In November 2016 commercial and contractual terms for Phase I of the project were agreed. Phase I, which involves drilling one well at a water depth of 450 metres, may produce 1.3-1.5 bcm/year of gas from 2020 to be delivered to the domestic market. After Phase I production starts, a decision will be taken, with commercial factors in mind, on whether to go ahead with a second phase, which could produce 5 bcm/year.[10] If Phase II is developed, this will only be done after 2020, suggesting that production could start in the second half of the decade.

This year Azerbaijan has signed agreements with IOCs providing for exploration and development work at a number of smaller fields, of which two are of note. Firstly, on 30 May Statoil Azerbaijan (a subsidiary of Equinor of Norway, formerly Statoil) and Socar signed a risk service agreement, related to the appraisal and development of the Karabagh oilfield, and a PSA for the Ashrafi, Dan Ulduzu, and Aypara area. Statoil Azerbaijan and Socar will now form a 50-50 joint operating company to operate these licences, and an FID will be taken following appraisal and engineering work.[11] Industry sources estimate that when production starts, in the mid 2020s or later, the gas volumes from these fields may be 1.5 bcm/year in aggregate. No plan for marketing gas from these projects has been made public. Secondly, on 24 May BP and Socar signed a memorandum of understanding to explore jointly the D230 block in the North Absheron basin of the Caspian. The block covers 3200 sq km and has not been previously explored.[12]

In addition to these relatively small projects, there are two major gas resources – ACG non-associated (deep) gas, and Shafag-Asiman – which, if developed, will make a significant contribution to Azerbaijan's gas production. The ACG resource essentially lies beneath the ACG oil field, Azerbaijan's largest oil field. The international consortium of shareholders of the ACG field have for several years been in discussion with the government about possible legal frameworks for development of the gas resource. In December 2016, BP (operator of the consortium) and Socar signed a letter of intent on the future development of the oil field up to 2050, but there has been no progress with regard to the gas. If the negotiations were to be concluded rapidly, exploration and development might still be completed by the mid 2020s, providing for 2-5 bcm/year of gas output.[13] The Shafag-Asiman resource is covered by a PSA between BP and Socar signed in 2010. Seismic data was collected and interpretation of it began in 2014, planning for a first exploration well continues and this year it was reported that options for deploying a drilling rig – which are limited in the Caspian – were under discussion by the companies. Socar has given 2030 as a possible date for the start of production, which is expected to peak at 8 bcm/year.[14]

Socar fields. Socar operates the Shallow Water Guneshli field, and a large number of smaller fields. The commercial gas output from these fields was estimated at 5.8 bcm in 2015 and 5.27 bcm in 2016,

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[9] BP Caspian web site; BP presentation, "BP in Azerbaijan. Baku, September 2006", slide 43; Pirani, *Azerbaijan's gas supply squeeze*, pp. 9-10

[10] Total press release, 21 November 2016; "Interview: Azerbaijan to open first phase of Southern Gas Corridor to Turkey in July", Reuters, 19 February 2018; "Terms of future drilling at Azerbaijan's Absheron gas field announced", *Azernews*, 20 April 2018

[11] Equinor press release, 30 May 2018; "Equinor signs new agreements in Azerbaijan", *World Oil*, 30 May 2018

[12] BP press release, 24 May 2018; "Socar, BP ink contract for Caspian block", *Natural Gas World*, 26 April 2018

[13] "BP, Socar agree terms for future development of ACG field", *Offshore Energy Today*, 23 December 2016; Pirani, *Azerbaijan's Gas Supply Squeeze*, p. 10

[14] "Socar Pending Opening of a New Large Gas Field", *Caspian Oil & Gas News*, 5 June 2017; "BP Azerbaijan may use Heydar Aliyev rig at Shafag-Asiman", *Azernews*, 31 May 2018

slightly lower than in the early 2010s, when output was 6-7 bcm/year.[15] Technologically Socar faces two challenges: to develop new fields, and to work over old ones to slow down the rate of natural decline. The first new gas resources slated for development are the Umid field, discovered in 2010, and the adjacent Babek field. These are high-temperature, high-pressure resources, and Socar, having reduced output from Umid by 50 per cent in 2014 due to technical difficulties, has decided to try to attract international companies to develop them. A risk-service contract was signed last year between Socar and Socar-Umid, a joint venture owned by Socar (80 per cent) and Nobel Upstream (20 per cent), and Socar is continuing discussions with international oil companies (IOCs) about working in the area. Exploration drilling is planned but no date has been fixed for it.[16] It now seems unlikely that the Babek field could reach peak output by 2025.

In conclusion, there are a number of fields, operated by IOCs and by Socar that could contribute substantially to Azerbaijan's gas balance during the 2020s. But only one of them, Absheron, is now in development. At several others, including Shafag-Asiman and some of Socar's fields, preliminary agreements have been signed, but exploration has yet to begin. When the fields are considered together, constraints including the number of exploration rigs in the Caspian (now three – the Deda Gorgud, the Istiglal, and the newly-launched Heydar Aliyev), and the corporate capacities of Socar, need to be taken into account. Some of the fields mentioned could start production in the mid or late 2020s – but not all of them, because of such constraints. Bearing these points in mind, Azerbaijan's commercial gas output in 2020 could be 32-36 bcm (including 20.5-23.5 bcm from Shah Deniz, depending on how rapidly Phase II ramps up), rising by 2030 to 32.6-54.4 bcm (including about 18 bcm from Shah Deniz, which by then will be in decline). These illustrative projections are shown in Table 3, below.

It is important to underline the modest scale of these prospects, in order to counter the vague and exaggerated statements that regularly appear in the media, not only from senior Azerbaijani officials, but also from researchers. Officials regularly referred to the southern corridor's potential to bring 60 bcm/year to Europe before the 2013 FID on Shah Deniz phase II (16 bcm/year),[17] and continued to do so afterwards. In a presentation in 2014, Vitaly Baylarbayov, Socar's vice president, said that the southern gas corridor "can be scaled up to 60 bcm", to carry gas from Central Asia, Iraq, and the East Mediterranean, as well as Azerbaijan; in 2016, Natiq Aliev, Azerbaijan's energy minister, envisaged expansion of the South Caucasus pipeline to 50 bcm/year.[18] These figures contrast with the 23 bcm/year capacity of the South Caucasus line (after expansion), and of TANAP's 16 bcm capacity – with even an expansion to 32 bcm/year now unlikely. Forecasts of production activity are also exaggerated. This year, directly after the fourth ministerial meeting, one researcher asserted that "the most movement is taking place in developing additional fields in Azerbaijan, such as Shah Deniz Stage 3 and a variety of unmapped smaller fields. […] Drilling is taking place in these untapped fields and finance is being put in place."[19] In reality, not even preliminary agreements have been signed on Shah Deniz Stage 3; the only untapped field being drilled is Absheron; geological surveys have been done at Shafag-Asiman but no exploration; and the other projects mentioned await FIDs.

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[15] Estimates extrapolated from Azerbaijan's total commercial gas output, minus the output of Shah Deniz and ACG associated gas. Socar does not report output of commercial gas. It reports total production prior to reinjection and flaring, which was 6.87 bcm in 2015 and 6.27 bcm in 2016. Socar *Annual Report* 2016, p. 21.

[16] "Socar outlines new offshore terms", *Argus FSU Energy* 22 September 2016; "Baku Advances Umid-Babek Plans", *Natural Gas World*, 9 February 2017; "Ilham Aliyev approves contract", Trend news agency, 11 May 2017; Nobel Upstream press release, 27 March 2018

[17] See, for example, "Azerbaijan drives the planning on TANAP project", *Eurasia Daily Monitor*, 11 September 2012

[18] Speech by Natiq Aliev at the Caspian Oil and Gas Conference, Baku, 1 June 2016; presentation by Vitaly Baylarbayov, dated August 2014, stored at <https://www.slideserve.com/eliot/the-southern-gas-corridor>.

[19] Interview with Brenda Shaffer, Adjunct Professor, Georgetown University, *Politico Pro Morning Energy and Climate*, 16 February 2018

Gas demand in the Azerbaijani and Georgian markets

Azerbaijan's own gas consumption fell during the 1990s to 5.5 bcm in 2000, but has risen steadily since then, exceeding 10 bcm in 2012 and (according to an initial news report), exceeding 12 bcm in 2017.[20] All the indications are that, during the 2020s, gas demand will either continue at the present level or increase, albeit more slowly than previously. Table 3 below shows an illustrative projection of consumption rising from 12 bcm/year to 14 bcm/year by the end of the 2020s. One of the reasons that gas consumption could grow is Azerbaijan's rising population. Its largest user of gas, the national power generation company Azerenerji, continues to increase electricity output both for domestic use and for small volumes of export to Iran; a new thermal power plant is due to be commissioned in 2018. There is a continuing programme of expansion of gas storage capacity.[21] This increasing domestic demand has required Azerbaijan to import small volumes of gas since 2015, first from Russia, and then from Turkmenistan, by way of swaps through Iran.

Imports from Russia began in 2015 under a contract to Azmeco, a petrochemical producer, but ceased after three weeks. Socar held discussions with Gazprom in 2016-17, and then in November 2017, amid concerns of a shortfall of gas over the winter, signed a contract for the purchase of 1.6 bcm of gas. About 0.35 bcm of Russian gas was imported in 2017; it is understood that a preliminary agreement is in place allowing for imports of 1.5 bcm in 2018 and 1.5 bcm in 2019.[22]

Imports from Iran, which are widely believed to originate in Turkmenistan and to be delivered under a swap arrangement, were probably about 1.2 bcm in 2017. They are expected to continue at that level this year and next. It is understood that the gas is supplied to Turkmen companies by Petronas, from its operations in the Turkmen section of the Caspian, and then swapped via the National Iranian Oil Company.[23] (These are separate from deliveries to the Nakhchivan enclave of Azerbaijan, which has for many years received 0.35-0.4 cm/year of gas that originates from Azerbaijan itself, and is delivered via Iran under a swap arrangement.)

In addition to the demand for Azerbaijan's gas in its domestic market, there is a call on it from Georgia. Throughout the post-Soviet period, Georgia has imported gas from Russia; part of these imports are delivered as payment in kind for Georgian transit of Russian volumes to Armenia, and the rest are paid for in cash. Since the South Caucasus Pipeline was completed in 2006, Georgia has imported gas from Azerbaijan and, for political and strategic reasons – particularly following the Russia-Georgia war of 2006 – has aimed to increase imports from Azerbaijan and reduce those from Russia. Georgia's imports from Azerbaijan comprise gas from Shah Deniz, delivered in lieu of transit fees on the South Caucasus pipeline, and additional volumes from Socar. Georgia's gas demand, like Azerbaijan's, is rising, and in recent years has exceeded 2 bcm/year. Georgia imported 2.2 bcm from Azerbaijan in 2015, and about 2 bcm in 2016, enabling it to suspend deliveries from Russia, apart from the volumes used to pay for transit. In January 2017, the contract under which Russian gas was delivered expired; Georgia had to renegotiate it under circumstances whereby Azerbaijan's supply was potentially over-committed. Moreover, Gazprom proposed to end the gas-for-transit arrangement and to monetise both transit fees and the purchase of gas imported by Georgia. The Georgian government eventually reported that it had agreed with Gazprom to pay for imports partly with transit services and partly with cash in 2017, and to move entirely to cash transactions in 2018. In line with its policy of minimising imports from Russia,

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[20] Julian Bowden, "Azerbaijan: from gas importer to exporter", in Pirani (ed.), *Russian and CIS Gas Markets*, pp. 203-234, here p. 219; Pirani, *Azerbaijan's gas supply squeeze*, pp. 3-5; "Socar reveals volume of gas supplies", Trend, 23 January 2018

[21] "Parviz Shakhbazov: Azerbaidzhan igraet vazhnuiu rol v energobezopasnosti", Trend News Agency 8 May 2018; "Socar to boost storage capacity", *Argus FSU Energy*, 2 March 2017

[22] "Gazprom vernulsia v Azerbaidzhan", *Vedomosti*, 23 November 2017; Gazprom press release, 22 November 2017; "Socar reveals volume of Russian gas imports", Trend, 23 January 2018

[23] "Azerbaijan, future gas supplier to Europe, faces shortfall at home", Reuters, 24 February 2017; Georgi Gotev, "Turkmenistan to tap into Southern Gas Corridor", Euractiv, 8 May 2018; David Jalilvand, *Progress, Challenges, Uncertainty: ambivalent times for Iran's energy sector* (OIES, April 2018), p. 3

Georgia has set its 2018 gas balance at 2.69 bcm, of which it plans to import 2.68 bcm from Azerbaijan.[24]

Armenia is not expected to require volumes of Azerbaijani gas. Armenia imports gas from Russia, and supplements those volumes with a minimal quantity of imports (0.37 bcm in 2016 and 0.34 bcm in 2017) from Iran, under a gas-for-electricity swap deal.[25]

Estimates of the gas balances of Azerbaijan, Georgia, Armenia, and Turkey are shown in Table 2. The figures highlight the importance of Russian and Iranian imports for these countries.

Table 2: The Caucasus and Turkey: estimated gas balances, bcm

2017		**Azerbaijan**	**Georgia**	**Armenia**	**Turkey**
Production		18.6	0.006	0	0.3
Imports	Russia	0.3	0.2	1.9	29
	Iran	1.2	0	0.4	7
	Azerbaijan	-	1.9	0	5.5
	Other/LNG	0	0	0	4.7
Total		**20.1**	**2.1**	**2.3**	**46.5**
Consumption		12.7	2.1	2.3	46.5
Exports	Georgia	1.9	-	0	0
	Turkey	5.5	0	0	-
Total		**20.1**	**2.1**	**2.3**	**46.5**

Sources: company information, press reports, estimates

Projections of the level of consumption of Azerbaijani gas in Azerbaijan and Georgia during the 2020s should be put in a broader context. It is in Gazprom's commercial interest to sell gas volumes, at a profit, to customers in Azerbaijan and Georgia who are served by existing pipelines. But it is not in Gazprom's interest to sell at a price lower than the European netback, otherwise it could be freeing up volumes of Azerbaijani gas for export to Europe, where it would compete with Gazprom's gas. Gazprom's sales price to Georgia, as reported in 2017, was $185/mcm. Other wholesale gas prices in the region are not generally reported; however, a price marker is provided by Greenfields Petroleum, a US-based producer that operates a small joint venture with Socar, and which reported its well-head prices as $139.83/mcm in 2016 and $94.99/mcm in 2018.[26] It may be assumed, therefore, that Azerbaijan's gas will always go first to satisfy its own and Georgia's domestic demand, before volumes are exported further westwards. That assumption is made for Table 3 below.

Turkey and Europe as destinations for Azerbaijani gas

Some illustrative estimates of the possible level of Azerbaijan's gas production, and of the way in which it would be consumed, are shown in Table 3. For 2025 and 2030, "high" estimates of total production are given, based on assumptions that the most optimistic forecasts are realised – in particular, that Socar doubles its own production during the 2020s, and that by 2030 Absheron Phase II and Shafag-Asiman not only start up but reach plateau production. "Low" estimates indicate a more conservative

[24] "Georgia agrees with Gazprom's new transit terms", Civil.ge, 11 January 2017; "Opposition calls for Gazprom deal disclosure", Civil.ge, 23 February 2017; "Gazprom vernulsia v Azerbaidzhan", *Vedomosti*, 23 November 2017; "Socar names volume of gas export to Georgia", MENAFN, 9 April 2018; "Making the southern gas corridor work", *Natural Gas World*, 3 July 2018

[25] David Jalilvand, *Progress, Challenges, Uncertainty*, p. 3; "Iran says Armenia lagging on gas-power swap", *Natural Gas World*, 18 June 2018

[26] Greenfields Investor Presentation, *Revitalizing Mature Offshore fields in the Caspian Sea*, February 2018, slide 16

view of the speed at which new fields will be brought on stream. In compiling the table, it has been assumed that Azerbaijan's priority will be to cease imports, and that both its domestic consumption and exports to Georgia will rise gradually through the 2020s. The final rows indicate the volumes committed under existing contracts in Turkey and in European countries (from Shah Deniz Phase II).

Table 3: Illustrative projections of Azerbaijan's gas balance, bcm

		Actual			Est.		Illustrative projections					
		2014	2015	2016	2017		2020		2025		2030	
Production					Est.		low	high	low	high	low	high
Socar (including Umid-Babek)		6.17	5.8	5.25	5.5		5.2	7.8	5.4	9.9	6	12
ACG associated gas		2.76	3.2	2.75	2.88		2.8	3.2	2.8	3.2	2.8	3.2
ACG non-associated gas		0	0	0	0		0	0	0	2	0	5
Shah Deniz I		9.9	9.9	10.7	10.2		9.5	10.5	6.0	7.0	4.0	4.2
Shah Deniz II		0	0	0	0		11	13	16	16	13.8	14
Absheron phase 1		0	0	0	0		1.5	1.5	1.5	1.5	1.5	1.5
Future projects	Absheron phase 2	0	0	0	0		0	0	0	3	3	5
	Karabagh and Ashrafi, Dan Ulduzu and Aypara	0	0	0	0		0	0	0	1.5	1.5	1.5
	Shafag-Asiman	0	0	0	0		0	0	0	0	0	8
Other/ stock change		0.2	0.4	0	0		0	0	0	0	0	0
Imports		0	0	0	1.52		2	0	0	0	0	0
Total		**19.03**	**19.3**	**18.7**	**20.1**		**32**	**36**	**31.7**	**44.1**	**32.6**	**54.4**
Consumption												
Azerbaijan		11.03	10.9	10.7	12.7		12	12	13	13	14	14
Exports	Georgia	1.9	2.2	2	1.9		2	2	2.5	2.5	2.5	2.5
	Turkey - SD I and II contracts	6.1	6.2	6	5.5		9.8	12	6	6	6	6
	Europe - SD II contracts						8.2	10	10	10	10	10
	Residual available for Turkey and Europe	***0***	***0***	***0***	***0***		***0***	***0***	***0.2***	***12.6***	***0.1***	***21.9***
Total		**19.03**	**19.3**	**18.7**	**20.1**		**32**	**36**	**31.7**	**44.1**	**32.6**	**54.4**

Source: company statements, official statistics, author's estimates

In 2025 and 2030, the estimates show that – if the assumptions about the Azerbaijani and Georgian markets are correct – then, after the quantities specified in the Shah Deniz II contracts are delivered, there would be in the very best possible case 12.6 bcm of gas by 2025, and 21.9 bcm by 2030, for other deliveries in Turkey and Europe.

The first call on this gas will very likely come from customers in Turkey currently served under contracts for Shah Deniz I gas, which expire in 2021. The possible renewal of these contracts is currently under discussion – against a background of Turkish policy decisions to reduce dependence on Russian gas imports. This dependence was demonstrated in 2017, when imports from Russia rose sharply to 29 bcm, more than 5 bcm higher than 2016, despite the government's supply diversification policy.[27] If, for

[27] *Gazprom in Figures, 2013-2017*, p. 77. See also Gulmira Rzayeva, *Gas Supply Changes in Turkey* (OIES Energy Insight, January 2018)

example, new contracts were signed at the same level, of 6.6 bcm/year – and provided that the most optimistic forecasts on production are realised – this would leave 6.0 bcm of gas available for other customers in 2025, and 15.3 bcm in 2030. If new production is brought on at a more conservative pace, indicated by the "low" estimates, Azerbaijan, having delivered the required quantities under contracts already signed (in 2018), could have less than 1 bcm available for other customers in Turkey and Europe, whether under contracts that renewed or replaced those expiring in 2021, or under other future contracts.

The cost of delivering these volumes to Turkey will be lower than the cost of delivering to Europe's large markets; the difference will probably be around $90/mcm ($2.45/mmbtu) or more. The crucial comparison, shown in Figure 2 and Table 5 below (page 16) is between the estimated cost of transport from the eastern border of Turkey to the Eskisher off-take point in Turkey ($79/mcm) and the estimated cost of transport from the eastern border of Turkey to Italy ($103/mcm for TANAP, and $75/mcm for TAP, total $178/mcm ($4.85/mmbtu). These estimates were published in 2016 by the author on the basis of tariffs already set by the Turkish regulator for TANAP, and industry estimates for TAP tariffs.[28] Over time, and certainly by the end of the 2020s, these numbers may change – and could fall substantially – depending on the amortisation timetables for the pipelines and the evolution of the gas transport market in Turkey and Europe.

In future, therefore, particularly in an environment of high gas prices, Azerbaijani volumes may be potentially competitive in south-east Europe, and even in Italy. But for TANAP expansion to go ahead, two conditions have to be met: (i) investment has to be undertaken in the new fields, and marketing arrangements made for the production, and (ii) sufficient volumes committed for sale to Europe, rather than to Turkey, to make the expansion feasible. The case made here is that the 15 bcm of gas for Europe that would be the strongest economic underpinning for a second string of TANAP – the form of southern corridor expansion regularly mooted by Azerbaijani ministers and Socar managers – will be available only after 2030, and even then only if the most optimistic forecasts for production growth are realised and if economic logic does not divert too much of it to Turkey. It is more likely that the volumes available for Europe will be smaller.

Turkmenistan supply outlook, and trans-Caspian transport options

Renewed hopes of bringing gas from Turkmenistan into the southern corridor have rested on assumptions (1) that Turkmenistan is prepared for a major change in its export policy, and (2) that progress in political talks on the status of the Caspian Sea, and the delimitation of territorial waters, will allow a Trans Caspian pipeline to be built. The argument presented here is that Turkmenistan's export policy has not changed substantially; that even if agreement is reached on the Caspian delimitation issues, political obstacles to a pipeline project would remain; and that, most important of all, the economics of bringing gas from Turkmenistan to Europe would remain problematic, even if all the political issues were resolved.

Turkmenistan's export policy

In the last decade, Turkmenistan has gained China as an export destination, but lost Russia and Iran. Exports to China began in 2010 and rose to 28-29 bcm/year in 2014-16, and 31.7 bcm in 2017. Up to 2008, exports to Russia, or through Russia to Ukraine, were about 35-40 bcm, but they fell in 2009-15 to about 10-11 bcm. In 2015, Gazprom first negotiated a significant price reduction for imports from Turkmenistan, and then reduced them to zero; Gazprom Export has begun arbitration proceedings against Turkmengaz, requiring a price revision, but these have been put on hold in an attempt to find a

[28] See cost estimates in Pirani, *Azerbaijan's gas supply squeeze*, pp. 12-14

negotiated solution. Exports to Iran, which were 6-8 bcm/year until 2016, were reduced to zero in August 2017. Turkmen gas had historically been used in northern areas of Iran that had no link to Iran's own gas resources in the south, but following a history of tension over purchase prices and payments, and the completion of a 14.6 bcm/year pipeline linking Iran's gas fields to the north, purchases were stopped.[29]

Gas is Turkmenistan's principle export and principle source of foreign currency revenue, and the combined effect of the cessation of exports to Russia and Iran, and the fall in oil-linked gas prices in 2015-16, has had an adverse effect on the economy. The estimated price at the Turkmen border for gas exported to China fell from just over $300/mcm in 2013-14 to $215 in 2015, $165 in 2016, and $185 in 2017. Moreover, some revenues are being used to repay loans from Chinese banks for the development of the Galkynysh gas field. The effect of the consequent fall in revenues on the budget, and the economy as a whole, is not evident from government statistics, but it is certainly a major factor in the trade balance, which has throughout the 2000s been positive, surpassing $5 billion in 2011 and 2012, but which turned negative in 2015. (See Table 4.) Other widely reported serious economic problems include: a sharp fall in the black-market level of the manat, from 7 to the dollar in late 2016 to 24-25 this year (compared to an official rate of 3.5); shortages of consumer goods; non-payment of debts by Turkmen firms to foreign suppliers; redundancies and accumulation of wages arrears by Turkmen firms; and restrictions on cash withdrawals by the main banks. Significantly, in April this year, Turkmenistan, for the first time ever, declined permission for publication of an Article IV report by the International Monetary Fund on its economy and finances.[30]

Table 4: Turkmenistan foreign trade, in $ billion

$ billion	2010	2011	2012	2013	2014	2015	2016	2017
Exports	9.7	16.8	20	18.9	19.8	12.2	7.2	7.8
Imports	8.2	11.4	14.1	16.1	16.6	14.1	13.2	10.2
Balance	***1.5***	***5.4***	***5.8***	***2.8***	***3.1***	***– 1.9***	***– 6.0***	***– 2.4***

Sources: Turkmen stat; CIS Stat, Foreign Trade of the CIS, various years

Turkmenistan is clearly at an important turning-point: its economic policy, based in recent years on natural resource extraction and large-scale, state-funded projects, has become unsustainable. However, as this crisis has been building, there have been few signs that decision-making processes are becoming more flexible. Important policy decisions continue to be taken by the president and a very small number of advisers, in an opaque political system that has minimal experience in dealing with foreign interlocutors. While a new export opportunity has been taken – the provision of small volumes to Azerbaijan (see above) – the manner in which it has been negotiated shows the limitations of governance.

Oil companies that operate offshore oil and gas fields in the Turkmen sector of the Caspian, tens of kilometres away from the eastern-most Azerbaijani fields, have for several years reportedly been in talks with the government about the small volumes of associated gas that they produce. It is understood that some of this gas is brought onshore in Turkmenistan and processed and some is flared. Proposals to build a small pipeline into the Azerbaijani sector, and possibly pay a tolling fee for processing and make the volumes available for export either to Azerbaijan or Europe, have made no progress, although there are no significant technical problems for the companies involved. While such a link is seen in the

[29] BP *Statistical Review* (on exports to China); "Gazprom zakliuchil piatiletnyi kontrakt s Uzbekistanom", *Vedomosti*, 6 April 2017; "Turkmeniia lishilas' krupnogo pokupatelia gaza v litse Irana", *Vedomosti*, 13 August 2017

[30] "Foreign companies struggle in cash-strapped Turkmenistan", Reuters, 4 June 2018; "Turkmenistan: fast and furious. And broke", Akhal-Teke Bulletin, Eurasia.net, 15 May 2018; "Sokrashcheniia v neftegazovom komplekse", *Alternativnye novosti Turkmenistana*, 13 June 2016; "Vnesheconombank imposes new restrictions", Chronicles of Turkmenistan web site, 14 December 2017; IMF Turkmenistan web page

industry as an efficient means of making use of associated gas, and a potential preparation for a larger trans-Caspian link, the government has instead preferred the swap scheme with Iran.

Insofar as the government has paid attention to opening up new export routes, it has publicly focused on the proposed Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline. In February 2018 a ceremony was held at the Turkmen-Afghan border to mark the "completion" of the Turkmen section of the pipeline, but industry sources state that, of the 217 km route, only 7-23 km have been constructed. Construction of the Afghan section of the pipeline has begun, with the approval of the Taliban, which controls much of the route. Although a price mechanism for future contracts has been agreed, there is no evidence of any purchase contracts for Turkmen gas in Pakistan or India, a precondition for the success of such a project. It has been reported in Pakistan and India that Turkmenistan is bearing 85 per cent of the estimated $7.5-10 billion cost of the project, although it is clearly unable to do so.[31]

Certainly gas demand is likely to continue to rise on the Indian sub-continent. It is possible that in the 2030s, with a different price environment in India and Pakistan, and different dynamics in LNG markets, there could be demand for pipeline gas from Turkmenistan. Even in this case, though, a much greater level of commitment would be needed from the purchasing countries for the financing and implementation of pipeline construction, if TAPI is to be successfully completed.

Turkmenistan's public enthusiasm for TAPI, which is unlikely to be completed in the 2020s, and its reluctance to engage even with modest proposals by commercial partners to take small volumes of gas across the Caspian, is indicative of its government's failure to formulate the rudiments of a future export policy. Given the other obstacles to a trans-Caspian pipeline set out below, it is a mistake – made surprisingly often by observers – to take occasional statements of approval for trans-Caspian options by Turkmen officials as real steps towards implementation.

Political factors in the Caspian

One long-standing obstacle to a proposed Trans Caspian pipeline has been the unresolved legal status of the Caspian Sea, and outstanding demarcation disputes between some littoral states. In December 2017, hopes were raised that these issues might be resolved, following a meeting in Moscow of the foreign ministers of the littoral states (Russia, Kazakhstan, Turkmenistan, Iran, and Azerbaijan). Sergei Lavrov, the Russian foreign minister, announced that agreement had been reached on all the key issues, and that a Convention on the legal status of the Caspian would be prepared for heads of state to sign at a summit in Kazakhstan during 2018. It soon became clear, though, that Lavrov's optimism may have been premature. Moreover, while such an agreement would certainly remove a significant legal obstacle to a Trans Caspian pipeline, political and strategic obstacles would remain.

Following Lavrov's statement, Iranian and Azerbaijani officials cast doubt on the extent of progress made in the negotiations. Elmar Mammadyarov, the Azerbaijani foreign minister, said "some issues were still in dispute". Ebrahim Rahimpour, a senior Iranian diplomat, said that Lavrov's suggestion that demarcation lines had been finalised was "false and unfounded". This appears to reflect Iran's long-standing dispute with Azerbaijan on the demarcation of territorial waters. As of mid 2018, it is unclear whether the disputed issues have been settled. But in June, Dmitry Medvedev, the Russian prime minister, signed a decree approving the draft convention, and in July, it was announced that it would be put to heads of state for their signature at a summit on 12 August in Aktau, Kazakhstan.[32]

The draft Convention on which Russia is working has not been published, but reports of it have appeared in the Russian media. The draft includes a clause on the construction of underwater pipelines,

[31] "Acceleration plan approved to lay TAPI", *Express Tribune* (Karachi), 1 May 2018; "A $7.5 billion pipeline has surprise patrons", *Times of India*, 9 March 2018

[32] "Caspian Sea FMS agree to draft convention", *Astana Times*, 6 December 2017; "No revision in Iran's stance", *Iran Front Page*, 15 December 2017; "Signs of progress emerge on Caspian offshore delimitation", *Offshore*, 9 Feb 2018; "Sammit glav prikaspiiskikh stran proidet 12 avgusta", *Kommersant*, 17 July 2018

stating that consent for them is needed only from the states on whose territory they were built – clearly implying that a pipeline from Turkmenistan to Azerbaijan would not require consent from the other three states. On naval activity, the draft Convention specifies that the Caspian Sea is closed to the armed forces of all countries except the littoral states. This reflects the strategic and military concerns of Russia, which is constructing a naval base at Kaspiisk, Dagestan, for completion by 2020.[33]

Russia's position has changed: its priority appears to be to consolidate its strategic and security position in the Caspian, in line with its more active role in central Asia and the Middle East. Whereas for many years Russia, along with Iran, was content to leave the Caspian delimitation issues unresolved, it has now taken the initiative to achieve a treaty. Its new approach takes into account (1) its wider strategic relationship with Iran, and (2) its concern about Islamist insurgency spilling over from Afghanistan to central Asian countries, which was a key factor underpinning the strategic partnership agreement signed between Russia and Turkmenistan in October last year.[34] There seems to be no reason to assume that Iran, the littoral state that has been the least willing to reach an agreement, could not be convinced to do so in the broader context of Russian-Iranian relations.

A Caspian treaty is not a legal prerequisite for a Trans Caspian pipeline, according to a consensus of legal opinion – but it would be an important political underpinning. However, a treaty would not be sufficient to ensure that such a pipeline is built. Azerbaijan has publicly remained open to discussion of pipeline projects, but as proposals come nearer to implementation would surely act in its own commercial interests. The advantage of earning transit revenues from a pipeline corridor across its territory would be balanced against the disadvantages of opening a transit corridor to Turkey, if not Europe, to a competitor with much larger, more fully-developed gas resources. Delay, at least during the 2020s, would be a potentially attractive approach. Iran, even if it is persuaded to enter into a Caspian treaty, may also have commercial incentives to oppose pipeline construction – and could propose, for example, expansion of the gas swap schemes described above as an alternative.

Trans-Caspian transport options, and unfavourable economics

While political conditions for building a Trans-Caspian pipeline are still far from favourable, ultimately it is economic factors that make it very unlikely. The cost of transporting Turkmen gas to Europe via a yet-to-be-constructed pipeline makes that gas less competitive than other options, in particular, additional Russian imports and LNG.

Estimates for the cost of delivering Turkmen gas to Turkey and to European destinations via a future Trans-Caspian pipeline are shown in Figure 2, with the numbers on which the estimates are based shown in Table 5. There are two nominal purchase prices shown for Turkmen gas at the Turkmen border in Table 5. The lower of the two, $80/mcm ($2.94/mmbtu), is below the current cost of delivery of Russian gas to the Russian border ($120-128.50/mcm or $3.25-3.50/mmbtu). Turkmenistan could certainly deliver gas to its border at this price: industry sources estimate operating costs at Turkmenistan's eastern gas fields are $18-25/mcm; to this should be added the cost of transit through the East-West pipeline, which was completed in 2015 but is not used. However the tax revenue from sales at this price would be modest. The higher nominal purchase price, of $150/mcm ($4.09/mmbtu), assumes a higher tax take for the Turkmen government, similar to the level it achieved from gas exports to and through Russia in the 2000s. For the cost of transit via a Trans-Caspian pipeline, calculations made by the IEA in 2010 have been used. The IEA estimated the cost of constructing the pipeline at $2.0 billion; this is similar to an estimate of $2.2 billion made by IHS CERA in 2010.[35] Other transport

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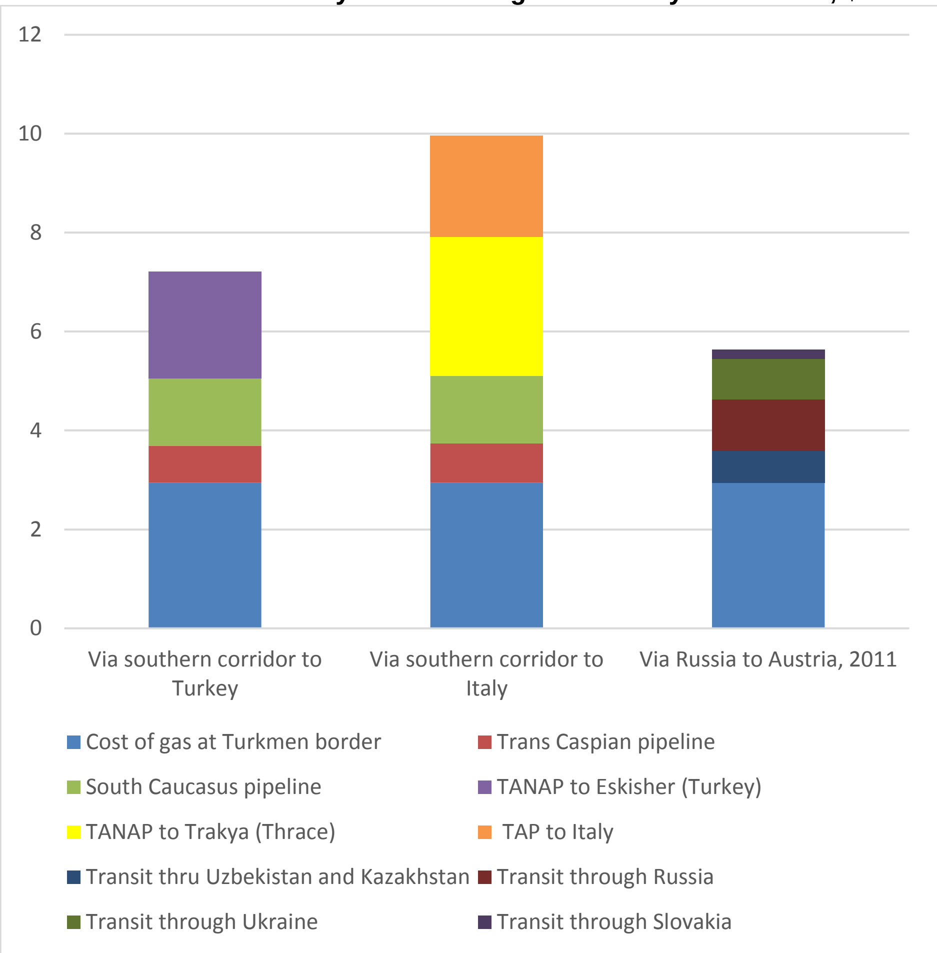
[33] Samuel Ramani, "Russia's security inroads with Turkmenistan", *The Diplomat*, 24 November 2017; "Kabmin utverdil proekt Konventsii o pravovom status Kaspii", TASS, 22 June 2018; "Russian government approves draft convention on the Caspian Sea", *Eurasia Daily Monitor*, 27 June 2018.

[34] Stephen Blank, "Is there an agreement on Caspian Sea delimitation?" *Central Asia-Caucasus Analyst*, 25 January 2018.

[35] IEA *World Energy Outlook* 2010, pp. 541-542; IHS CERA, *Caspian Development Corporation Final Implementation Report* (Cambridge, Ma: IHS CERA, December 2010), p. 76. White Stream Ltd gives an estimate of $800 million for the first string of a

costs are based on industry information for the South Caucasus pipeline and a future Trans Adriatic Pipeline, and actual tariffs being charged on TANAP.[36]

Figure 2: Estimates of cost of delivery of Turkmen gas to Turkey and the EU, $/mmbtu



Source: Author's calculations

Trans Caspian pipeline, assuming it is commissioned concurrently with TANAP and TAP. This is clearly no longer feasible, but the company does not provide other estimates. See <http://www.white-stream.com/two-entry-points-for-guaranteed-off-take/>

[36] These are also used in Pirani, *Azerbaijan's Gas Supply Squeeze*, pp. 12-13

Table 5: Estimates of cost of delivery of Turkmen gas to Turkey and the EU

	Assuming $80/mcm border price			Assuming $150/mcm plus border price	
	$/mcm	**$/mmbtu**		**$/mcm**	**$/mmbtu**
1. Via southern corridor to Turkey					
Cost of gas at Turkmen border	80	2.94		150	4.09
TCP to Azerbaijan	27.52	0.75		27.52	0.75
SCP to Turkish border	50	1.36		50	1.36
Via TANAP to Eskisher (Turkey)	79	2.15		79	2.15
Total	**236.52**	**7.2**		**306.52**	**8.4**
2. Via southern corridor to Italy					
Cost of gas at Turkmen border	80	2.94		150	4.09
TCP to Azerbaijan	27.52	0.8		27.52	0.8
SCP to Turkish border	50	1.36		50	1.36
Via TANAP to Trakya (Thrace)	103	2.81		103	2.81
Via TAP to Italy	75	2.05		75	2.05
Total	**335.52**	**9.96**		**405.52**	**11.11**
3. Via southern corridor to Turkey and Europe - IHS Cera, 2010					
Cost of gas at Turkmen border				154.44	4.21
TCP to Azerbaijan				13.33	0.36
SCP 1 extension and SCP 2				22.22	0.61
Southern corridor				70.00	1.91
CDC operating and capital costs				13.33	0.36
				273.33	**7.45**
4. Via Russia to Austria, 2011					
Cost of gas at Turkmen border	80	2.94		150.00	4.09
Transit through Uzbekistan 200 km	7.00	0.19		7.00	0.19
Transit through Kazakhstan 820 km	16.40	0.45		16.40	0.45
Transit through Russia 1100 km	38.50	1.05		38.50	1.05
Transit through Ukraine 950 km	30.00	0.82		30.00	0.82
Transit through Slovakia	7.00	0.19		7.00	0.19
	178.90	**5.64**		**248.90**	**6.78**

Note. Items (1) and (2) are developed from estimates published in Pirani, *Azerbaijan's Gas Supply Squeeze*, p. 13. Item (3) has been extrapolated from IHS Cera's published assumptions on southern corridor economics, *CDC Final Implementation Report*, p. 79.

The estimates show that, assuming a low purchase price at the Turkmen border, the transport cost of $156.62/mcm ($4.27/mmbtu) to Turkey means that Turkmen gas could compete there, but not easily, with Russian and Azerbaijani supplies. The transport cost of $255.52/mcm ($6.96/mmbtu) to Italy is essentially prohibitive: it is difficult to see circumstances under which Turkmen gas could compete with other supplies in Italy over any extended period. The dynamics governing the competitiveness of Azerbaijani gas in Turkey, south-eastern Europe, and Europe's main markets, as discussed on pages 10-11, would apply to Turkmen gas delivered via a Trans-Caspian route even more forcefully. As in the case of Azerbaijani gas, lower tariffs on southern corridor pipelines – possible depending on amortisation timetables and changes in transportation markets – would lower the costs displayed in

Table 5. A period of higher gas prices could certainly attract Turkmen gas to Turkish and south-eastern European markets and, in the event of extreme and unexpected changes, even further. But there is as yet no indication of such a congruence of changes in the 2020s.

In addition to the authors' estimates, Table 5 also shows the transit tariffs implied by a major economic study of the southern gas corridor by IHS CERA in 2010. The research was commissioned by the European Commission, the World Bank, and the European Investment Bank, to inform discussions about the Caspian Development Corporation being established as a single European-based buyer of Turkmen gas. The hope was that the CDC, by guaranteeing to purchase substantial volumes at the Turkmen border, would not only help to make a Trans-Caspian pipeline succeed economically, but would also overcome political obstacles by encouraging Turkmenistan to shift its export policy towards Europe. Brussels pushed on with the CDC, despite indications from major European energy companies that it flew in the face of the principles of market liberalisation that had underpinned European energy policy for twenty years.[37]

The CDC failed because neither Turkmen export policy nor European energy policy moved in the direction that would have been necessary for it to progress. Table 5 shows that it probably would also have failed for economic reasons. The level of tariffs implied by IHS CERA's economic assumptions, shown in the table, subsequently turned out to be too low. Current estimates of tariffs on the South Caucasus pipeline ($50/mcm or $1.36/mmbtu) are more than twice as high as IHS CERA's implied estimates ($22.22/mcm or $0.61/mmbtu). The actual current level of tariffs for transit via TANAP ($103/mcm or $2.80/mmbtu) is substantially higher than the figure implied by IHS CERA for the entire southern corridor, including additional transport from the Turkish border to European destinations ($70/mcm or $1.90). In other words, it is not so much the cost of construction of the Trans-Caspian pipeline that makes it economically unviable, but the combined cost of construction and of getting gas to Europe from the western shore of the Caspian.

There are other trans-Caspian transport options, for example the short link from the westernmost Turkmen fields to the easternmost Azerbaijani fields, as mentioned above; or conversion of gas to LNG or Compressed Natural Gas (CNG) for transport by ship. The short link, while a convenient method for supplying Turkmen gas to Azerbaijan, could not carry significant volumes for further export. Liquefaction or compression are prohibitively expensive: the IEA estimated the cost of transporting 5 bcm/year across the Caspian in this form was $51.40-73.40/mcm ($1.40-2/mmbtu).[38]

In economic terms, swaps via Iran would be more competitive than any of these options, but may incur political obstacles. Significantly, reports have appeared that Iran is in discussions with Armenia about increasing its gas exports. Observers have speculated that Turkmenistan could also export to Armenia via Iranian swaps.[39] But until the political situation with respect to western sanctions on Iran changes, and new infrastructure is built, it is difficult to see how such routes could carry more than a few bcm/year, or how they could become transit corridors to Europe.

Finally, the economic feasibility of Turkmen exports to Europe via a Trans-Caspian pipeline should be compared to the feasibility of exports via Russia. In November last year, Myrchat Archaev, the president of Turkmengaz, publicly raised the prospect of exporting Turkmen gas via the Russian route, "through which Turkmenistan historically exported gas". Russian researchers quite correctly pointed out that, under present conditions, Gazprom would not give a direct competitor access to its pipelines.[40] Nevertheless, this has been a major export route in the past, and whether or not it could be resurrected is ultimately a commercial decision. Prior to 2005, Turkmengaz, the Turkmen producer, sold volumes

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37 See also Pirani, *Central Asian and Caspian Gas and the Constraints on Export*, pp. 99-102

38 IEA *World Energy Outlook* 2010, op. cit.

39 "Iran pins hope on Armenian transit", *Natural Gas World*, 9 July 2018

40 "Turkmeniia khochet postavliat' gaz v Evropu po trubam Gazproma", *Vedomosti*, 3 November 2017; "Turkmenistan is ready to supply gas to eastern Europe via Russia", *Chronicles of Turkmenistan*, 3 November 2017

to a variety of traders for export by this route. From 2005, Gazprom denied these traders direct access to its export pipelines, and switched to buying the gas at the Turkmen border, renegotiating prices on the principle of European netback. In 2009, under conditions of economic crisis and severe oversupply in the Russian market, Gazprom reduced purchases from Turkmenistan sharply and in 2015 they stopped all together.[41]

Anyone who considers Trans-Caspian pipeline construction as likely must ask themselves: if Gazprom management was faced with the imminent launch of a Trans-Caspian pipeline, might it not change its attitude? The pipeline route via Russia to Europe is shorter than the route via Azerbaijan and Turkey. The infrastructure was built long ago and is available. Gazprom could offer either to buy the gas at the Turkmen border at a premium, or to transit it on terms favourable in comparison to the southern corridor. While Gazprom would prefer not to encourage a direct competitor, it might prefer to profit from offering that competitor limited access to a route to Europe that it controls, rather than allowing a new route to be opened up. In the mid 2000s – in a high gas price environment – Turkmen gas was brought to Europe via Russia by Ukrainian-based traders and sold at a comfortable margin. Gazprom effectively limited the volumes, then took over the business, and then put an end to it. If it considered reopening this route to be in its strategic and commercial interest, it could do so. From the point of view of European policies directed at reducing dependence on Russian gas, this would be a negative development, but from Turkmenistan's point of view, it might well be viewed as positive.

The argument presented here is not that a resumption of Turkmen exports via Russia is likely before 2030, but that it is less unlikely than an FID on a Trans-Caspian pipeline.

Other potential suppliers

The joint declaration of the Southern Gas Corridor Advisory Council meeting in February, in addition to enumerating gas resources in Azerbaijan, welcomed "potential additional suppliers of natural gas" from the Caspian Basin, Central Asia, the Middle East, the Eastern Mediterranean Basin, and the Black Sea. There are some countries in these areas that could export modest volumes of gas to Europe before 2030, whereas others are almost certainly excluded by market conditions. Published research indicates the following:

Iran is by far the largest gas producer among potential suppliers to the southern corridor, but is very unlikely to make any substantial contribution to it before 2030, because of (i) its focus on the domestic market and the new export corridor to Iraq, and its longer-term interest in exporting LNG, and (ii) the political uncertainty caused by US sanctions. In the decade to 2017, Iran's output rose from 128 bcm/year to 224 bcm/year, making it the world's third largest gas producer after the US and Russia. Since 2001, Iran has exported small volumes of gas (4-9 bcm/year) to Turkey, but the trade has always been constrained by disputes over prices. Iran has also conducted the swap trades with Turkmenistan, Azerbaijan, and Armenia mentioned above. But most of its production is consumed domestically, and that is expected to continue. Iran has invested in storage facilities to mitigate winter supply bottlenecks and built pipelines to bring gas from the south-eastern producing regions to the northern regions previously supplied by Turkmenistan.

The most significant recent development has been the start-up in June 2017 of Iranian gas exports to Iraq. In early 2018 these were running at about 5 bcm/year and were planned to expand to 12-13 bcm/year. It is possible that a second pipeline to Iraq will be built in the coming years. David Jalilvand has argued convincingly that the rapid progress made on exports to Iraq, where there are no significant

[41] Pirani, "Central Asian and Caspian Gas for Russia's Balance", in Henderson and Pirani (eds.), *The Russian Gas Matrix: how markets are driving change* (Oxford: OUP, 2014), pp. 347-367

political complications, strikes a contrast with the slow pace of discussions on exports to Pakistan and Oman.[42] Obviously the political obstacles to exports to Europe are much greater. At the time of writing, the re-imposition of US sanctions has thrown doubt on Total's South Pars project, Iran's largest gas production project by far – which, it should be recalled, is directed at LNG markets, not at pipeline export to Europe. It may take some years for such doubts to clear, by which time Iran's focus on Iraq and other export routes may have been consolidated.

Kurdistan has gas resources sufficient to underpin a modest volume of exports to Turkey, but political factors rule out much progress in the next few years. And even if the political situation changes, the commitment to Kurdistan by Russian oil and gas companies may work against Brussels's conception of the southern corridor as a means to diversify from over-dependence on Russia. Kurdistan's political direction will be shaped in part by the independence referendum held in September 2017 and the Baghdad government's military action to retake control of Kirkuk and adjacent oil and gas fields in October 2017. Until the political situation is stabilised, it is difficult to see progress on plans for exports to Turkey. Even if this happens, it may well be that Russia will play a key role, and coordinate export policy to Turkey with its own. Prior to the referendum, the Kurdistan Regional Government had agreed with the Pearl Consortium of Turkish and European companies to provide gas for export, and with Rosneft of Russia to construct a 30 bcm pipeline to Turkey; this is part of a broader strategical commitment to Kurdistan by Rosneft. Although industry sources are sceptical that Kurdistan could produce such volumes of gas, or that Turkey could consume them, the influential position of Rosneft underlines that it is Russia, not Europe, which has made progress in building a strategic partnership with Kurdistan.[43]

Central Asian countries. Both Uzbekistan and Kazakhstan have small volumes of gas available for export, but many of the constraints that apply to Turkmenistan – the geographical distance to Europe, the implications for transit costs, and the availability of other export routes – are even greater for these countries. The cost of transport via a Trans-Caspian pipeline would be even higher for them than for Turkmenistan. Both Uzbekistan and Kazakhstan export small volumes of gas to China and, unlike Turkmenistan, continued their exports to Russia through the 2008-09 economic crisis and up to the present; in 2017 Uzbekistan signed a framework agreement with Gazprom providing for 4 bcm/year of exports over five years. Kazakh gas is competitive with Russia's own gas in the southern Urals, due to the cost of transport from Russia's main fields.[44]

East Mediterranean. The development of the Tamar and Leviathan fields in Israeli territorial waters has shown not only the potential for gas production in the East Mediterranean, but also the fact that gas exports from the region are far more likely to go via Egypt than via pipeline to Europe. The agreement signed earlier this year between Noble Energy, Delek of Israel, and Dolphinius Holdings of Egypt indicates that both governments and companies in the region see export to Egypt, either for domestic use or possibly for further export as LNG, as the most attractive option. Export to and via Egypt is also the most plausible option for the Aphrodite field in Cypriot territorial waters, although the demarcation dispute between Israel and Cyprus in the area could forestall development. Some exports from Leviathan may also reach Jordan; that is the most likely route, too, for fields in Lebanese waters. All this suggests that the plans for a pipeline from Israel to Italy will remain frozen, due (i) to the poor

[42] Jalilvand, *Progress, challenges, uncertainty*, op. cit; BP *Statistical Review* 2018.

[43] "Rosneft Plans Key Gas Pipeline", *Middle East Economic Survey*, 22 September 2017; "Russia's Rosneft holds key to fixing Iraqi Kurdistan oil flows", Reuters, 5 March 2018; "KRG: foreign firms press on amid uncertainty", *Middle East Economic Survey*, 4 May 2018

[44] "Gazprom zakliuchil piatiletnyi kontrakt s Uzbekistanom", *Vedomosti*, 6 April 2017; "Uzbekistan lifts gas production", *Argus FSU Energy*, 12 April 2018; Pirani, *Central Asian and Caspian Gas and the Constraints on Export*, pp. 87-88

political relations between Israel, Cyprus, and Turkey, which have already frustrated the plans for several years, and (ii) to the poor prospects for the gas being able to compete in the European market.[45]

Black Sea. There are fields in Romanian and Bulgarian territorial waters being explored by IOCs. In particular, Romania's energy minister has said that Exxon and OMV Petrom are expected to announce a decision on a Black Sea offshore investment in 2018.[46] Such fields could be developed in time for some gas production in the late 2020s, but there is as yet no confirmation that the volumes of available gas would be sufficient to impact materially on the southern corridor strategy.

Transport and demand issues

The supply issues discussed above have been the main constraints on the expansion of the southern corridor. But the level of demand in European and Turkish markets, and the level of gas prices – which are low relative to the costs of delivery of southern corridor gas – have also constrained the southern corridor's progress, and will continue to do so.

The cost of delivering gas from Azerbaijan has been estimated at $273-293/mcm ($7.54-8.09/mmbtu) to Italy, and $179-189/mcm ($4.94-5.22/mmbtu) to Turkey.[47] The cost of delivering gas from Turkmenistan, assuming it is purchased at the Turkmen border for $80/mcm ($2.94/mmbtu), is estimated (see above, Table 5) at $335.52/mcm ($9.96/mmbtu) to Italy, and $236.52/mcm ($7.20/mmbtu) to Turkey. There are, of course, uncertainties in these estimates. For Azerbaijani gas, a $50-60/mcm production cost has been assumed, while the average from Shah Deniz I has been $43.95/mcm in the past decade.[48] For Turkmen gas, the assumed price at the border includes production costs, transport to the border, and export taxes; these may be higher or lower, but no matter how these figures are adjusted, it is clear that such volumes would struggle to compete in the large European markets against alternative sources of supply.

In the next few years, imports to Europe are likely to remain dominated by Russian gas, with competition from rising volumes of US LNG. The cost of delivering fully costed Russian gas from the Yamal peninsula to Europe is estimated at $6.50/mmbtu, and the long-run marginal cost of delivering Russian LNG to Europe at $5-7/mmbtu. The cost of delivering US LNG to Europe, given a Henry Hub price of $2.60/mmbtu (February 2018), is estimated at $4.30/mmbtu (short-run marginal cost) and around $7.00/mmbtu (full long-run marginal cost, i.e. including all capital expenditures for US LNG projects).[49] Much of the infrastructure to deliver these sources of supply to Europe is already in place, and it is logical to assume that they can compete at current price levels on the European exchanges of around $6.00/mmbtu, and also at lower prices of $4.00-5.00/mmbtu. Azerbaijani gas is much less competitive in Europe at current market prices, and indeed gas produced from deep-sea deposits and transported over long distances will always struggle to compete in a low price environment. A recent survey of East Mediterranean gas prospects reached a similar conclusion: whether transported as LNG or by pipeline, it would be priced above $7/mmbtu, and "cannot match average gas prices in Europe trading hubs

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[45] Bassam Fattouh and Laura El-Katiri, *Lebanon: the next Eastern Mediterranean Gas Producer?* (Washington: the German Marshall Fund of the US, 2015); Antonia Dimou, *East Mediterranean Gas Cooperation and Security Challenges* (*National Security and the Future* [Zagreb] 1-2 (2017), 2016); Necdet Pamir, "Eastern Mediterranean, Cyprus and Natural Gas", Sigma Insight, 26 December 2017; Egypt-Israel Mega Deal, *Financial Mirror* (Cyprus), 20 February 2018; Charles Ellinas, "Pragmatic Approaches to the E Med", *Natural Gas World* 3:9, 14 May 2018; "Aphrodite's Blues", *Executive* (Beirut), 6 June 2018

[46] "Romania's OMV Petrom/Exxon to unveil Black Sea gas decision", Reuters, 28 September 2017

[47] Pirani, *Azerbaijan's gas supply squeeze*, p. 13

[48] "Making the southern gas corridor work", Natural Gas World, 25 June 2018

[49] Henderson and Sharples, *Gazprom in Europe*, p. 14 and p. 16

around $6/mmbtu".[50] On the other hand Azerbaijani gas can be competitive in Turkey, and potentially competitive in the small markets of south-eastern Europe.

In Europe's largest markets, the downturn in demand in 2009-14, the limited nature of the demand recovery, forecasts of very gradual demand growth in the 2020s, and the large volumes of Russian gas and LNG that are potentially available, all mean that prices could remain low. This prospect has inhibited pipeline projects in general, and played a part in reducing the scale of the southern corridor in comparison to initial expectations. The commercial constraints that apply to southern corridor gas in Italy also apply to proposals to transport it to central Europe, such as the White Stream project, which envisages a pipeline running north-westwards across the Black Sea to Romania, and the Bulgaria-Romania-Hungary-Austria pipeline project, the latest iteration of which will stop in Hungary.

The prospects for southern corridor gas in south-east Europe are brighter, because of its geographical proximity to Turkey, and because of the focus on security of supply and reducing dependence on Russian imports. Here Romanian gas production could play a role, and the possibility of it being transported to Ukraine by reversing flow along the Trans Balkan pipeline is under discussion. Other transportation projects supported by the EC as part of its southern corridor initiative, and through the Central and South-Eastern Europe Gas Connectivity (CESEC) initiative include proposed reversible interconnections between Greece and Bulgaria, Turkey and Bulgaria, and Bulgaria and Romania. Even in south-eastern Europe, though, southern corridor gas will have to compete with Russian supplies. If and when the Turkstream 2 pipeline is built – with the possibility of it arriving in Bulgaria, rather than Turkey, under discussion – it will bring Russian gas more directly to the region.[51]

The prospects for larger-volume gas sales to Turkey from Azerbaijan, and possibly Iran, before 2030 are favourable relative to the potential sales to all European destinations. First, gas demand in Turkey is likely to increase during the 2020s, albeit not as rapidly as previously expected.[52] Second, Turkish policy is directed at diversifying sources of imports, and, assuming that transport bottlenecks can be overcome, it will be able to accept greater volumes from Azerbaijan and Iran. The first indication of these possibilities will be in news about the negotiations on the renewal of Shah Deniz I contracts. As in Europe, southern corridor gas will have to compete with Russian gas, which – assuming that ways are found to expand transportation capacity if necessary, either via Turkstream 2 or an additional string of Blue Stream – could also flow to Turkey in larger quantities.

Conclusions

To assess the potential for the southern corridor during the 2020s, five groups of factors need to be taken into account:

Prices and market conditions. Azerbaijani gas will struggle to be competitive in Europe's large markets in a low-priced environment. The prospects for Turkmen, Iranian, or East Mediterranean gas to reach Europe during the 2020s are very poor for supply-side reasons, but market conditions in Europe – and, in particular, gas transport costs – will act as a further deterrent to projects.

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[50] "Pragmatic approaches to the E Med", *Natural Gas World*, 14 May 2018
[51] "Kiev targets new gas sources with TBP reverse flow", *Interfax Natural Gas Daily*, 6 April 2018; Christian Egenhofer and Cristian Stroia, *CESEC 2.0: Opening the door to a new level of regional cooperation* (CEPS Policy Insight, September 2017); "Gazprom considering extending TS2 to Bulgaria", *Interfax Natural Gas Daily*, 24 May 2018; "Romania prepares for greater cross-border flows", *Interfax Natural Gas Daily*, 21 June 2018
[52] Gulmira Rzayeva, *Turkey's gas demand decline* (OIES, 2017)

Turkey and south-eastern Europe. Azerbaijani gas, and possibly other southern corridor gas (for example, Black Sea or East Mediterranean production) could be brought to Turkey or south-eastern European destinations competitively, more easily than to larger European markets.

Alternative sources of supply. Russian investment in the Yamal peninsula from 2007, and investment in US LNG export facilities and European regasification facilities in this decade, means that other sources of imported gas are available for the European market at lower cost. When the political efforts on the southern corridor began in the early 2000s, the Russian commitment to Yamal was not confirmed, and the US LNG boom had not begun. Since then, these factors have complicated the southern corridor's prospects.

The attraction of non-European markets. Countries seen by the EC as potential suppliers to the southern corridor have made investments in alternative export routes: Turkmenistan to China, Iran to Iraq, East Mediterranean producers to Egypt and Jordan, and so on.

Timing. Azerbaijan, the only country with discovered gas resources which is likely to contribute materially to the southern corridor during the 2020s, would struggle to develop all those resources simultaneously. Finance, construction capacity, and project capacity in a broader sense, are all constraints. Although in aggregate the new fields can produce substantial volumes, it is most likely that they will be developed one after the other, and therefore will not all be in production by the end of the 2020s.

In terms of pipeline infrastructure, the most likely next step in the expansion of the southern corridor is the expansion of TANAP to 32 bcm, from its current capacity of 16 bcm. From the arguments presented above, it follows that the necessary conditions for such an expansion prior to 2030 include (i) that Azerbaijani gas output grows in line with the "high" estimates in Table 3, and (ii) that the call from Europe for the volumes available is greater, and more commercially attractive, than the call from Turkey. It is possible, but far from certain, that these conditions will be fulfilled, and only towards the end of the 2020s. It is hard to see how a TANAP expansion could be undertaken earlier than that, unless, for example, there is a dramatic change of Azerbaijani production and export policy, combined with a dramatic increase in forecasted gas demand in Europe and in forecasted price levels.

The prospects for a Trans-Caspian pipeline – which, despite the scepticism of most of the gas industry, remains at the centre of political discussions on the southern corridor – before 2030 are even less promising. Necessary conditions for its construction include (i) a drastic change in Turkmenistan's export policy, which in turn would require at least a neutral attitude to the project by Azerbaijan, Russia, and Iran, (ii) a dramatic increase in long-term gas demand forecasts, and price forecasts, for Turkey and Europe, (iii) a long-term lack of availability of gas that can be brought to Europe, in particular south-east Europe, at a lower cost than Turkmen gas, for example additional Russian supplies, LNG or Azerbaijani gas, and (iv) a commercial decision by Gazprom not to disrupt a Trans-Caspian pipeline by re-opening the northern route.

The lack of these conditions, and the lack of much prospect that they would materialise, are surely among the reasons why the CDC initiative, designed to spearhead political attempts to bring Turkmen gas to Europe, was unsuccessful. The reasons for its failure have not been the subject of any public statements by senior EC officials, or prominent European politicians, that I have been able to trace. Neither has there been any public reflection on the fact that assumptions in EC policy about the role the southern corridor will play in Europe's gas balance by 2020 were out by a factor of between five and ten. A reconsideration of these issues might help to recalibrate European expectations for the southern corridor at a more realistic level.

It is implicit in the arguments made here that things could be very different after 2030. There could be substantially higher volumes of gas available from Azerbaijan; some of the political obstacles to bringing gas to Europe from Iran, Kurdistan, or the East Mediterranean may have been overcome. But such factors that would favour southern corridor expansion could be cancelled out by other trends. Serious implementation of decarbonisation policies could mean that gas demand in Europe is further reduced. Other potential sources of supply may have expanded by then. Longer-term political and economic changes may affect not only potential southern corridor suppliers, but also others: for example, it may ease the way to higher Russian imports in to Europe, or to imports from Ukraine.

The realistic prospects for the southern corridor prior to 2030 remain in a range between continuing at the expected 2020 level of supply, or undertaking a moderate expansion, e.g. by a second string of the TANAP pipeline.

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