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Perspectives on Caspian Oil and Gas Development

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Please note that these working papers were prepared in autumn 2008 and reflect the information available as of October 2008.

As these papers are works in progress, designed to elicit comments and further debate, comments are welcome, directed to Tim Gould (Programme Manager for the Caspian, Caucasus and Southeast Europe) at tim.gould@iea.org.

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Introduction

The Caspian region is one of the oldest hydrocarbon producing areas in the world, and is emerging once again as a major source of growth in global oil and gas supply. In the IEA's medium-term projection for global oil supply to 2013, the Caspian is projected to increase its oil production by over 800 kb/d by 2013, representing some 70% of the net increase in non-OPEC oil supply growth during this period. Likewise, for natural gas, the region has the potential to make a significant contribution to the global gas balance, with Azerbaijan and Kazakhstan joining established producers Turkmenistan and Uzbekistan as net gas exporters.

The working papers collected here were originally prepared by the Directorate of Global Energy Dialogue of the International Energy Agency for meetings in October 2008 on the Caspian region. The Caspian is at the historic crossroads between Europe and Asia, and this collection provides perspectives on the region for a number of key regional partners, namely Russia, China, Iran, India and Europe, assessing their efforts to develop investment and infrastructure links with the region as well as examining how the August 2008 conflict between Russia and Georgia might affect prospects for Caspian energy development and export.

Russia is the incumbent energy partner for many Caspian countries, and has been looking to strengthen these ties. Nonetheless, alternative routes to market have already been put in place, notably for Azerbaijan oil and gas export through the South Caucasus, and there is continued strategic interest from all points of the compass to reinforce Caspian market diversity through new infrastructure projects. Many of these new projects remain at the planning stage and have yet to overcome stiff political and commercial challenges. The major exception is China, whose efforts to promote eastward export of Caspian resources have made much swifter progress: the construction of a gas pipeline from Turkmenistan eastwards to China, once completed, is set to have a major impact on both the economics and politics of Caspian gas.

By making these working papers available to a wider audience, the International Energy Agency aims to provide a basis for informed debate about the changing dynamics for energy cooperation and infrastructure development across the Caspian region. The collection is not, and does not claim to be, a comprehensive picture of energy developments in the region. In particular, it does not examine in detail the strategies and policies pursued by the Caspian countries themselves, which have evolved along different paths since 1991 and which – more so than the policies of external actors – are critical in shaping the energy future of the region. These policies and strategies continue to be an important focus for IEA analysis and for dialogue with partner countries.

These working papers are designed to elicit further comment and debate, and – with the hope that they are both useful and thought-provoking – we look forward to feedback and comment from readers.

Overview of Caspian Oil and Gas Production and Export

2007 Caspian Oil Production and Export

Table 1 shows the export volumes and estimated breakdown by route for oil from the Caspian basin in 2007 - not including exports from the non-Caspian regions of Kazakhstan, Turkmenistan or Russia. The largest exporter of Caspian oil in 2007 was Kazakhstan with more than 1.04 mb/d (around 52 mt for the year[1]), followed by Azerbaijan and then Russia. Russian oil exports from the Caspian region (including Russian volumes exported through the Caspian Pipeline Consortium, or CPC, pipeline) account for only around 3% of Russia's total oil export.

Table 1: Exports of oil from the Caspian basin, estimated breakdown by route (2007)*

Route	Export		Sources of Oil (in mt)
	kb/d	*mt/y*	
Tengiz-Novorossiysk (CPC Pipeline) *Kazakhstan – Russia*	652	32.6	Kazakhstan (25.6) Russia (7.0)
Baku-Tbilisi-Ceyhan (BTC Pipeline) *Azerbaijan-Georgia-Turkey*	570	28.5	Azerbaijan
Atyrau-Samara Pipeline *Kazakhstan-Russia*	320	16.0	Kazakhstan
Baku-Batumi *Azerbaijan-Georgia: by train*	136	6.8	Azerbaijan (4.4) Kazakhstan** (2.4)
Baku-Novorossiysk Pipeline *Azerbaijan-Russia*	134	6.7	Azerbaijan (2.3) Kazakhstan*** (4.4)
Neka *Iran: deliveries by barge*	112	5.6	Turkmenistan (3.5) Kazakhstan (2.1)
Total	*1 924*	*96.2*	

Sources: IEA, Energy Charter Secretariat estimates

** Does not cover exports from non-Caspian regions of Kazakhstan (85 kb/d [4.5 mt/y] exported to China from central Kazakhstan), Turkmenistan or Russia*
*** Kazakh shipments by barge to Baku*
**** Kazakh shipments by barge to Machakala (Russia)*

The CPC pipeline from Tengiz in Kazakhstan to the Russian Black Sea port of Novorossiysk was the main export pipeline for Caspian oil in 2007, followed by the Baku-Tbilisi-Ceyhan (BTC) pipeline Azerbaijan to the Turkish Mediterranean port of Ceyhan. The Atyrau-Samara line leads north from the Caspian shore and feeds into the Transneft pipeline network. For the moment, there is no quality bank for the Transneft system, which means that exports of light, sweet crude from Kazakhstan along this route is mixed with Urals blend and loses value as a result. Deliveries to the

[1] Conversion between oil volumes and weights is approximate and done throughout this paper at 1 million barrels per day = 50 million tons per year.

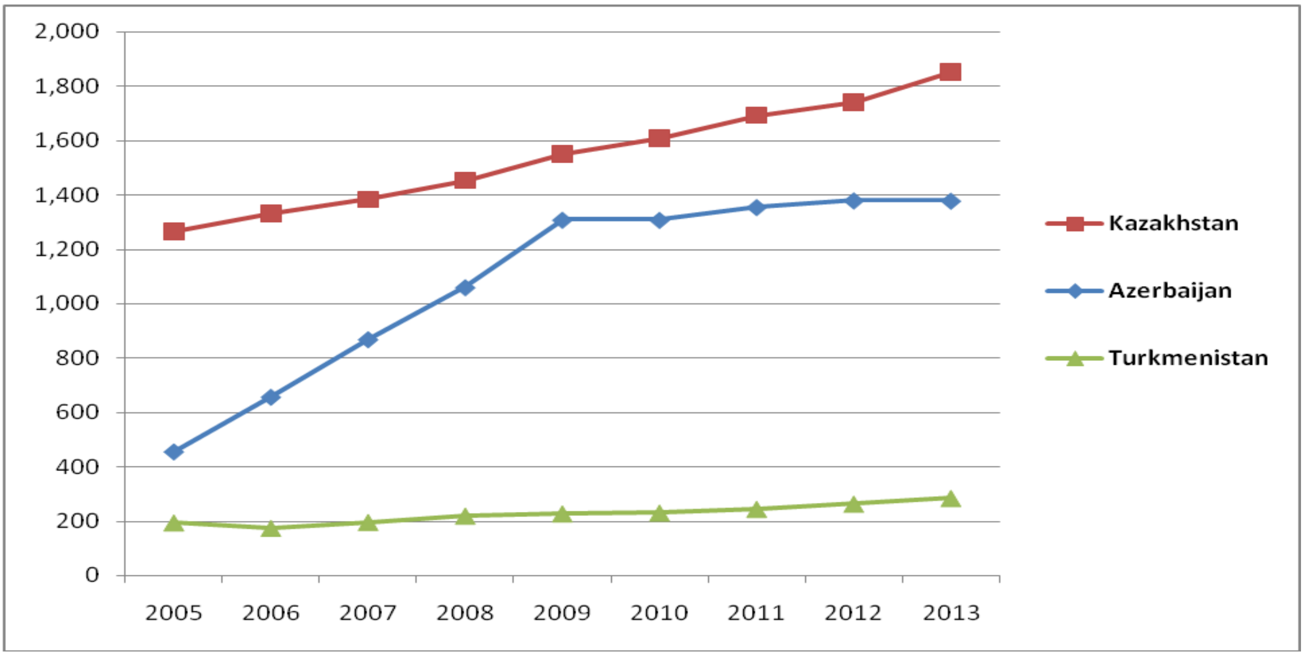
Iranian Caspian port of Neka are swaps, with equivalent quantities and grades of oil being made available at Iran's ports in the Gulf.

Similar patterns of export flows have been observed in 2008, with two notable additions. Firstly, around 100 kb/d (up to 5 mt for the year) of rail shipments from the Tengiz field in Kazakhstan went to the Ukrainian Black Sea port of Odessa via Russia. Secondly, deliveries along the Baku-Supsa pipeline between Azerbaijan and Georgia resumed in summer 2008, before being suspended as a result of the conflict in Georgia. This line, which was completed in 1999 as a route for early oil out of the Azeri-Chirag-Guneshli (ACG) complex in Azerbaijan, was not operational in 2007 due to repairs.

Oil Production Outlook

In ***Kazakhstan***, production has doubled to 1.4 mb/d (70 mt/y) since 2000, and robust growth is expected to continue through 2013 based on the existing Tengiz and Karachaganak fields. Expansion of the CPC pipeline from Tengiz to Novorossiysk on Russia's Black Sea coast was still stalled at the time of writing. CPC expansion had until recently been seen as an essential prerequisite for higher Tengiz and, later, Kashagan volumes. But a degree of export diversification has been achieved using rail, pipeline shipments to China and plans to expand trans-Caspian shipments to Baku and onwards through the BTC pipeline and other routes. This allows a continued steady increase in Kazakhstan production over the next 5 years, reaching 1.85 mb/d (92.5 mt/y) in the IEA's forecast by 2013.

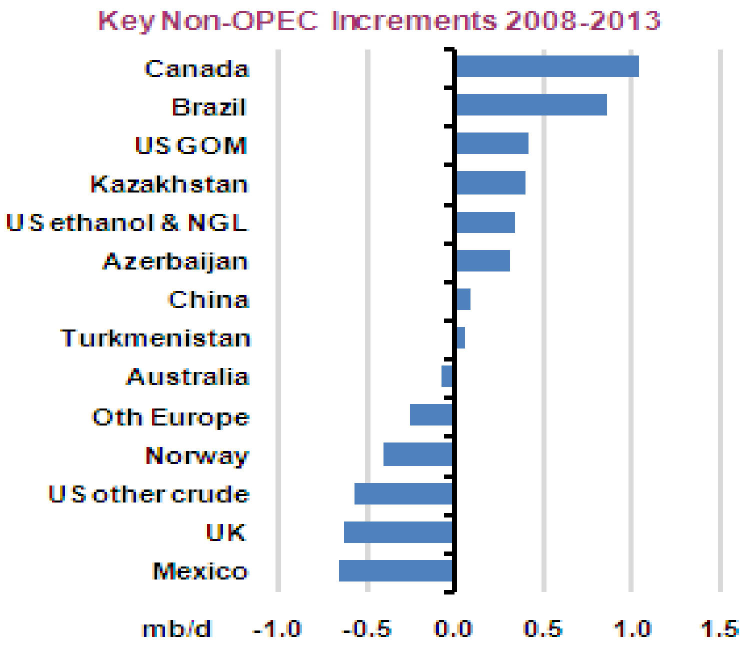
Figure 1: Oil production outlook for Kazakhstan, Azerbaijan and Turkmenistan (kb/d)



Source: IEA: MTOMR 2008

A key change to the forecast for Kazakhstan in the IEA's July 2008 Medium-Term Oil Market Review was a scaling back of expectations for the Kashagan project. Although early volumes could be higher than previously assumed (at 370 kb/d versus 250 kb/d; 18.5 mt/y versus 12.5 mt/y), first oil is assumed only from 2013 rather than 2011. After 2013, once Kashagan ramps up production, total Kazakhstan oil output could reach 2 mb/d by 2015 (100 mt/y), expanding further thereafter. For incremental exports to reach international markets, Kazakhstan will need to add some 800 kb/d of export capacity by 2013-15: this is now a key medium-term issue for Caspian oil export.

Figure 2: Main non-OPEC oil production increments, 2008-2013



Source: IEA: MTOMR 2008

In ***Azerbaijan***, production reached 870 kb/d (43.5 mt) in 2007 from around 650 kb/d (32.5) in 2006. The IEA sees sharper build-up in production from the BP-operated ACG fields, which are seen breaking through 1.0 mb/d (50 mt/y) in 2009. In addition, reports suggest upside recoverable reserve potential in the ACG complex could be as high as 9 billion barrels, versus existing estimates of 5.4 billion barrels. BP expects satellites at Chirag and Azeri will sustain production around 1.0 mb/d until 2015, with 2019 being cited in the event that higher resource levels prove accurate. Compared to Kazakhstan, (and even after the 2008 conflict in Georgia) Azerbaijan enjoys relative clarity over export infrastructure, with the main export route – the BTC pipeline – being supplemented by other options that provide access to the international market.

Kazakhstan: Can Export Capacity Keep Pace with Rising Oil Production?

The consortia behind the main upstream projects in Kazakhstan (Kashagan, Karachaganak and Tengiz, see Table 2 for details of shareholders) have all been affected by the Kazakhstan government's assertion of greater influence over the hydrocarbons sector. The most visible sign of this was the negotiations over the structure of the Kashagan consortium, now resolved in principle with an increased stake for KazMunaiGaz (reflected in Table 2 below). Chevron-led Tengizchevroil has also been under pressure over environmental performance, mainly related to the storage of sulphur (a by-product of oil production) around the site. Despite an exemption from new taxes under their production-sharing agreement, oil exports from Karachaganak have been subject to a new oil export duty of USD 109 per ton introduced in May 2008.

Higher fiscal take and uncertainty over the equity role of foreign companies could have an impact upon production and export. However, the main constraint on Kazakhstan's ambition to increase production to 2 mb/d (100 mt/y) by 2015 relates to export capacity.

Table 2: Stakes in selected Caspian production and pipeline projects (as of October 2008)

	Kashagan	Karachaganak	Tengiz	BTC	CPC
BG Group		32.50 %			2.00 %
ExxonMobil	16.81 %		25.00 %		7.50 %
Lukoil		15.00 %	2.70 %*		6.75 %*
Shell	16.81 %				3.68 %**
Total	16.81 %			5.00 %	
ConocoPhillips	8.40 %			2.50 %	
Inpex	7.55 %			2.50 %	
BP			2.30 %*	30.10 %	5.75 %*
Chevron		20.00 %	50.00%	8.90 %	15.00%
ENI	16.81 %	32.50 %		5.00 %	2.00 %
StatoilHydro				8.71 %	
TPAO				6.53 %	
Itochu				3.40 %	
Rosneft					3.82 %**
KazMunaiGaz	16.81 %		20.00 %		19.00 %
SOCAR				25.00 %	
Russia (Transneft)					24.00 %
Oman					7.00 %
Others				*2.36%*	*3.50%*

Source: IEA, EIA, Energy Charter Secretariat, company websites

* as LukArco
** as Rosneft / Shell

There are two longstanding factors, and one more recent consideration, that add complexity to the discussions about expanding export capacity. First, as the saga of CPC expansion demonstrates, decisions are often dependent upon political variables that are out of the control of the companies concerned. Second, there are a large number of different commercial and state entities involved in the main consortia, with some large companies having stakes in more than one upstream project and in different pipeline projects. This increases the difficulty of aligning interests and agreeing on tariffs and capacity rights. The new consideration is the potential impact of the Russia-Georgia conflict on the attraction of transportation routes through the South Caucasus.

2007 Caspian Natural Gas Production and Export

Table *3* shows the figures for natural gas production and export in 2007 for four Caspian natural gas producers: Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan.

Azerbaijan produced 11 bcm in 2007, becoming a net exporter of natural gas for the first time. The main sources of gas in Azerbaijan are offshore, and include fields operated by SOCAR (the national oil and gas company), associated gas from the Azeri-Chirag-Guneshli oil field that is operated by the Azerbaijan International Oil Company and – from December 2006 – the start of production from the major Shah Deniz gas and condensate field. Phase I of Shah Deniz output, which is scheduled to reach a plateau of 8.6 bcm per year, is being sold within Azerbaijan, and to Georgia and Turkey, with small volumes re-exported from Turkey to Greece.

Table 3: 2007 Natural gas production, consumption and export

bcm	**Production**	**Consumption**	**(Net) Export**
Azerbaijan	11.0	9.3	1.7
Kazakhstan***	12.9	10.6	2.3
Turkmenistan	72.3	18.0	54.3
Uzbekistan	65.3	50.6	14.7

Source: Country statistics; IEA, IEA estimates.

* Kazakhstan figures are from KazMunaiGaz for 'commercial' or 'sales' gas, i.e. net of technical use for oil production, and venting and flaring. The Kazakhstan Statistical Agency puts commercial gas production in 2007 at 16.7 bcm, consumption at 8.6 bcm. Kazakhstan gas statistics vary widely according to sources, with *total* gas production and consumption up to double the figures given here. Data also account differently for raw gas exported from Karachaganak to Russia for processing in Orenburg, some of which is then resold back to Kazakhstan.

Table 4: 2007 Natural gas exports, breakdown by destination

bcm	***Azerbaijan***	***Kazakhstan****	***Turkmenistan***	***Uzbekistan***
Total Export	1.7	2.3	54.3	14.7
- *to Russia*		5.5	48.1	10.5
- *to Iran*	0.2		6.2	
- *to Turkey*	1.2			
- *to Georgia*	0.3			
- *within C Asia*		(3.2)		4.2

Source: Country statistics; IEA, IEA estimates.

** Figures for Kazakhstan are estimates. As an indication of the varied figures available regarding Kazakhstan, Gazprom's annual report (2007) states that Russia imported 8.5 bcm from Kazakhstan and exported 10bcm, i.e. that Russia is a net exporter to Kazakhstan.

Nearly all ***Kazakh*** gas is associated with oil production, notably from the Tengiz and Karachaganak projects in the west of the country. Much of this gas is re-injected in order to maintain reservoir pressure and enhance oil output; gas flaring has also been prevalent, although this has decreased since 2005 as a result of government regulation.

Production of 'commercial' gas in Kazakhstan was 12.9 bcm in 2007, against consumption of 10.6 bcm. The main consumers of natural gas in southern Kazakhstan are distant from the production areas and are supplied primarily by imports from Uzbekistan. Kazakhstan has looked to reduce its dependence on occasionally erratic imports in the south by developing gas fields closer to the main population areas.

Turkmenistan is the region's largest producer, with output of 72.3 bcm in 2007. Domestic consumption of around 18 bcm in 2007 is high on a per capita basis, which is unsurprising given that natural gas is provided free of charge to residential consumers and is subsidised for industrial use. Nonetheless, the relatively small population (6.7 million) means that large volumes are still available for export.

In line with a long-term agreement signed in 2003, Russia is the main importer of Turkmen gas and – if gas and transportation capacity are available – current exports to Russia of around 48 bcm/y could increase to as much as 70-80 bcm/y after 2009. Exports along Turkmenistan's other current export route, to Iran, were interrupted in December 2007 with gas supply being strained by a dispute over pricing and also by exceptionally cold weather. Exports to China along a new pipeline from southeast Turkmenistan are scheduled to begin in late 2009.

Uzbekistan is also a major gas producer, with production of 65.3 bcm in 2007, but a relatively minor exporter (14.7 bcm in 2007) since the bulk of production is dedicated to the domestic market. Uzbekistan is the most populous of the former Soviet Central Asian republics (population of 26.7 million, 2006); domestic natural gas prices have remained low, and energy use, as elsewhere in Central Asia, is inefficient.

The majority of Uzbekistan's gas exports, 10.5 bcm out of 14.7 bcm in 2007, went to Russia – with the remainder going to its neighbours in Central Asia. Exports are expected to rise to 16 bcm in 2008; while Russia is likely to remain the most significant export market, the construction of a gas pipeline to China from Turkmenistan through Uzbekistan (and Kazakhstan) to China will open up the possibility of gas trade with China.

Pricing of Caspian Natural Gas Exports

East Caspian natural gas producers (i.e. Kazakhstan, Turkmenistan and Uzbekistan) have seen the prices offered for natural gas exports to Russia increase rapidly in recent years, from a base level that did not correspond to the market value of the gas and was often in the form of barter. In 2006, Turkmenistan was receiving USD 60 per thousand cubic metres (tcm) for gas exports delivered at the Turkmenistan border. From the last quarter of 2006 the price paid by Russia increased to USD 100/tcm, then to USD 130/tcm in the first half of 2008, and to USD 150/tcm in the second half of 2008. Prices paid for gas from Kazakhstan and Uzbekistan have followed a similar trajectory.

In March 2008, Gazprom and the heads of the national oil and gas companies from Turkmenistan, Kazakhstan and Uzbekistan announced that trade in Central Asian gas would, from 2009, take place at 'European-level prices'; this would imply a parity with the price paid on the European market for Russian natural gas, minus the costs of transportation and storage back to the relevant delivery point in Central Asia. The intention has been to move to a pricing formula, linked to the price for Russian export to Europe, which would limit the need for annual price negotiations.

Azerbaijan's gas exports under Shah Deniz phase I are committed to Georgia and Turkey under a contract signed in 2003. The contract included a price band of USD 70-120/tcm for export to Turkey, which expired in April 2008. Additional volumes of Azerbaijan gas from the Shah Deniz field are scheduled to be available for export from 2013. Alongside interest from Turkey and other downstream markets in Europe, Russia offered in June 2008 to purchase these volumes at 'European-level prices'.

Production Outlook

Azerbaijan has proven reserves of 1.3 trillion cubic metres, and substantial potential to expand gas production. Shah Deniz phase II development could bring additional gas to market from 2013, with volumes at least as large as Phase I, and possibly around or above 12-15 bcm per year; the consortium also announced in 2007 the discovery, beneath the currently producing structure, of a deep high pressure reservoir whose potential is now being assessed. Alongside Shah Deniz, there is the possibility of significant additional production from SOCAR fields as well as other deep offshore reservoirs. However, the timing, volumes, transit arrangements and marketing of gas supply after Phase I of Shah Deniz remain to be determined.

Kazakhstan has substantial natural gas reserves (1.9 trillion cubic metres), mainly associated gas. Total gas production is likely to increase substantially in the period to 2030, particularly with the start of production at Kashagan. As elsewhere in Central Asia, 'sour gas' is prevalent, i.e. with high levels of carbon dioxide and hydrogen sulphide, posing obstacles to development. Much of this gas is also likely to be re-injected as companies choose to optimise oil production. For these reasons, volumes of available 'commercial gas' are likely to be much lower than the headline figures for gas production. Estimates are that the volume of commercial gas could reach between 30-40 bcm by 2020, against anticipated domestic gas demand of 18-20 bcm.

Estimates of ***Turkmenistan's*** natural gas reserves vary considerably, introducing a large element of uncertainty into projections of its future contribution to global gas supply. Representatives of Turkmenistan have put total gas reserves in the country at more than 20 trillion cubic metres, an amount approaching the range of proven reserves in Iran or Qatar – and far more than the 2.7 trillion cubic metres included by BP in its statistical review (2008). Since 2006, Turkmenistan has announced new gas discoveries, the South Yolotan and Osman fields in the southeast of the country, and in August 2008 also a new gas condensate field, South Gutlyayak. The Turkmenistan government announced in April 2008 its intent to undertake an international audit of the country's gas reserves, and first findings of this audit were announced in October 2008. While more appraisal work is needed to confirm the reserves, the vast South Yolotan-Osman field (this is now considered to be a single structure) could hold an optimum 6 trillion cubic metres of gas, with estimates for the field ranging from a low of 4 trillion cubic metres to a high of 14 trillion. This finding alone would put Turkmenistan in the world elite of gas reserve-holders.

While much of the gas production thus far in Turkmenistan has been 'sweet', i.e. low hydrogen sulphide and carbon dioxide, there are likely to be more significant development challenges with much of the remaining gas (deep, high pressure high temperature, sour).

Further clarity over reserves and over the conditions for investment will be crucial in determining the path for gas supply developments in Turkmenistan and in buttressing the credibility of the government's intentions to raise production to 230 bcm per year by 2030[2]. With domestic consumption of 20-30 bcm/y, Turkmenistan is well placed to produce a substantial surplus of gas for export; there are contractual claims from Russia and China on a large share of these likely volumes.

Current gas production in Turkmenistan is primarily from onshore and mature fields in eastern Turkmenistan that were initially developed in the Soviet period. Major investment is required in order to compensate for declining output from existing fields and to develop new reserves. The government has stated that it welcomes foreign investment in offshore Caspian reserves, as well as assistance on a contractual basis to state-owned Turkmenneftegaz in developing onshore deposits, but international interest has yet to be turned into specific investment projects. While the bulk of Turkmenistan gas reserves are presumed to be onshore, offshore Caspian gas production could be in the range of 15-25 bcm/y by 2030. Investment in the upstream will determine Turkmenistan's ability to support multiple export routes.

Following signs of a slowdown in oil and gas output in 2005, ***Uzbekistan*** has sought to increase investment in exploration and production, and has concluded a number of new PSAs predominantly with Russian and Asian companies. As of 2008, Russia's Gazprom, Soyuzneftegaz and Lukoil, Malaysia's Petronas, China's CNPC, and Korean KNOC were the main companies operating in Uzbekistan, often in partnership with state-owned Uzbekneftegaz. Proven gas reserves in Uzbekistan are estimated at 1.7 trillion cubic metres. As long as domestic consumption remains high, it will be difficult for Uzbekistan to generate an exportable gas surplus of more than 20-25 bcm/y.

As shown in Table *4*, the bulk of Caspian gas exports go to Russia. Turkmenistan also exports relatively small volumes to Iran (6.2 bcm in 2007), and Azerbaijan also started in 2007 to export gas to Georgia and Turkey along the South Caucasus Pipeline, as well as very minor volumes south to neighbouring regions of northern Iran.

[2] Turkmenistan has struggled to meet previous targets for expanding gas output, for example a 1993 plan that foresaw gas production of 180bcm by 2000.

Russian Energy Strategy in the Caspian Region

- Russia's strategy in Central Asia has evolved over time, in particular with respect to its interest in the natural gas resources of some of the Central Asian states. It has developed from a position focused more on capturing Central Asian resource rent to one focused on commercial control and preventing competition by other potential players from the east or west.
- This strategy has become more costly to Russia – and the fact it continues down this route, despite higher costs, reflects Russia's increasing dependence on Central Asian gas supplies and concern about weakening its negotiating position vis-à-vis China.
- The potential option of future export routes to China (and Europe) has strengthened the Caspian countries' negotiating hand with Russia and enabled them to improve the price which they obtain for their product (previously very low).
- The Caspian producers have over the last couple of years no doubt welcomed the strengthening of their hands through having a range of potential customers; at the same time the greater political instability in the region could make Russian routes more attractive to Central Asian players, thus raising the stakes for investors interested in alternative routes and raising the price that consumers will have to pay for their energy.
- The way in which the recent Georgian conflict will play into these complex relationships is not yet clear.

Early Years After the breakup of the Soviet Union: from 1991-2000

The demise of the Soviet Union brought with it not only dislocation in manufacturing supply chains and from Moscow's perspective millions of stranded Russian citizens in newly established states, it is also brought to these newly established states a sense of independence for some never experienced before. Independence to some extent reflected itself in the liberalisation of investment regimes of these new states. Azerbaijan and Kazakhstan moved faster than other countries in the region to open their doors to foreign direct investment, thereby introducing commercial and political counterweights to the traditional relationship with Russia.

The opening of some Caspian states to foreign direct investment was a focus of all the oil majors which saw the Caspian as a new North Sea and the last region in the world where major fields could still be found. It was – and still is – seen as a key region for alternative oil and gas supplies helping to increase global energy security. Major international foreign investments were made in Azerbaijan (the Azeri-Chirag-Guneshli fields) and in Kazakhstan, notably the Tengiz and Karachaganak fields, already under development, and the supergiant Kashagan field with commercial reserves estimated at between 9 and 16 billion barrels, where production is expected to start up by 2014.

The Tengiz project stimulated the need for the Caspian Pipeline Consortium (CPC)[3] to build an oil pipeline. Its throughput has been in the order of 650 kb/d with the use of special drag agents. A key issue for investors in the Tengiz, Karachaganak and Kashagan fields is the need to expand export capacity from the region to ensure the viability of their upstream investments. There have been plans since 2002 to double the capacity of the CPC pipeline but no decision has been taken

[3] For more information see Annex: Caspian Oil and Gas Transportation Projects

as of autumn 2008. CPC is the only export pipeline on Russian territory with partial private ownership. Alternatively, the fact that Russian oil production is expected to plateau and domestic consumption to grow, may free up throughput export capacity through Russia. But this would mean increasing dependence on the Russian state monopoly pipeline, Transneft, something foreign investors have been careful to avoid, to date.

During the early years after the break up of the Soviet Union, energy relations between Russia and its former republics were important to Russia for political reasons. However, economically some of these new states were more of a burden than anything else to Russia. For instance, by 2001 Ukraine's gas debt to Gazprom was in the order of USD 1.4 billion. This arguably gave Russia more levers of control over these gas-importing states. However, it created huge headaches for Gazprom – already weakened economically by the rampant non-payment problems on the domestic front over much of the 1990s.

From 1999, Itera, acting as a middleman, supplied Turkmen gas in Ukraine. Ukraine paid Itera partly in gas supply (about 42% of the supplied gas) and in turn Itera paid Gazprom for transit. In December 2002, having problems with Itera management, Gazprom replaced Itera by another middleman by signing a transit agreement with Eural Trans Gas Kft (ETG). ETG was an offshore company registered in Hungary in December 2002 with an initial capital of 12 thousand dollars and unclear ultimate ownership. In accordance with a contract signed with Gazprom and Naftogaz of Ukraine, ETG agreed to supply from 2003 to 2006 Ukraine 36 bcm/y of Turkmen gas. For this service, ETG received annually a payment in kind of almost 15 bcm (or 38% of the gas transited), the worth of which varied by a factor of 3 depending on if it was sold in the CIS or in Europe. In turn, ETG paid a transit fee to Gazprom.

Apart from the sheer lack of transparency of these shell companies, a key question this raised was whether Ukraine was paying more than it should for the gas it received from Turkmenistan, given the existence of middlemen – Itera, from 1999-2002 and then ETG. The intervention of intermediaries for the gas transit which do not either own transmission assets or expertise raised more important questions for gas security. Offshore schemes usually raise eyebrows given the issues of tax evasion, potential losses to gas companies, suspicions of connections with Gazprom and NAK management, and potential overcharges for importers.

Against the background of an occasionally fractious relationship with Russia, and low prices paid for gas export, Caspian producers began in the 1990s to look at alternative routes to international market. One of these was the idea for a southern corridor for gas export through the South Caucasus and Turkey, including in the late 1990s the first attempt to build a trans-Caspian gas pipeline. Despite the best efforts of western governments to promote various options, the economics of private-company led projects did not meet the rate of return tests and criteria of the private oil majors. Moreover, the Russian government stepped in with a project that would meet Turkish demand and undermine the commercial rationale for a direct gas supply from the Caspian; the Blue Stream project – a Gazprom-ENI project to build a 16 bcm/year gas pipeline across the Black Sea. The Blue Stream pipeline was completed in February 2003 and has been used at well below design capacity (with throughput of 1.2 bcm in 2003 increasing to 5 bcm in 2005) until relatively recently (with throughput growing to over 9 bcm in 2007 and to 6 bcm during the first 7 months of 2008).

This pattern repeated itself in 2006 as momentum gathered behind the Nabucco pipeline that would bring gas from the Caspian and Middle East to the main European markets through Southeast Europe. This time Gazprom announced the proposal for a South Stream project (which would bring gas across the Black Sea to Bulgaria, then split into two pipelines supplying south and central Europe). Again, this demonstrated Gazprom's ability to deploy infrastructure projects to head off threats to its market position in Europe.

As International Oil Prices Began to Rise: from 2001 to the Present

With international oil prices increasing and subsequently rising European gas prices, Gazprom's commercial interest in the Caspian took off. The middlemen companies became less prominent and direct cooperation between Gazprom and gas producers from Central Asia was enhanced. Table 5 below reflects Gazprom's activities since the early-2000s with the various Central Asian states. These range from straight gas purchases and transit across the territories of Central Asia countries, gas processing at Russian plants as well as upstream and midstream activity. Azerbaijan is the one Central Asian state where this type of co-operation has not evolved, likely due to Azerbaijan's pro-active push to embrace foreign direct investment in their upstream development and to consider potential deals on oil and/or gas pipeline infrastructure which would avoid transit through Russia. In 2006, Russia increased its gas prices to Azerbaijan and as a result Azerbaijan cut its imports of Russian gas. One of the implications was to limit the potential for Azerbaijan's westward gas export flows as more gas was required for the Azeri domestic market. Nonetheless, from 2007, Azerbaijan began exporting gas to Georgia and to Turkey, and these volumes are set to increase.

Lukoil, Russia's 2nd largest oil producer (with almost 95% of its oil production within Russia), views the northern Caspian as one of the key regions to increase its oil and gas production in the medium term. The company is putting special focus on development of resource potential in the region. As a result of exploration work from 1995 to 2006, Lukoil discovered 6 major fields, most notably the V. Filanovsky field in 2005 with proven reserves of 1.6 billion barrels. By 2016, over 80% of the company's oil production from the northern Caspian region will be from this one field. Lukoil is the first Russian oil company to start the development of a major gas field abroad. In November 2007, development started in Uzbekistan at the Kandym-Kauhzak-Shady (KKS) project. Proved gas reserves in the KKS field at the start of 2008 totalled almost 100 billion cubic meters. Peak production in the project is expected at 12 bcm of gas which exceeds total production of natural gas by Lukoil in 2007. The outlook for Lukoil's Uzbek-based gas production is in the order of 15 bcm by 2013 from a level of about 3 bcm in 2008 – 80% of which from the KKS project. Overall, Lukoil is projecting a five to seven fold increase in its natural gas production from a level of about 10 bcm in 2008 to between 50 and 70 bcm in 2017. Over half of its natural gas production growth will come from Central Asia and a large part of that from Uzbekistan with the remaining growth from Lukoil's share in projects in Azerbaijan, including the Shah-Deniz field.

Russia's strategy to lock up vast amounts of natural gas in long-term contracts with Central Asian states can be seen in a geopolitical light and not only as a measure of necessity. The need to provide breathing space before starting up expensive natural gas projects at home, could just as easily, if not more so, have been met through more transparent and reliable access to its infrastructure by independent gas producers and oil companies. However, this would have meant restructuring and reform and a sharing of the increasing profits from gas exports. In the early years of this decade, Gazprom's continued dominance at home was integrally connected with Russia's geopolitical outlook in Central Asia. This is best reflected in a statement made by Yuri Komarov, then Deputy CEO of Gazprom, in an interview in early 2004, on his thoughts of the key successes of 2003:

> *"I would also highlight the developing process of the return of Gazprom to the gas markets of the countries of the CIS both from the point of view of inclusion in our portfolio of Central Asian gas (Kazakhstan, Turkmenistan and Uzbekistan), as well as from*

the point of view of broadening co-operation with importing countries (Ukraine, Moldova, and Trans-Caucasia). I believe this to be very important both from the perspective of guaranteeing the geopolitical interests of Russia as well as to assist in the integration process of the post-Soviet area.”

This strategy was not a new direction for Gazprom. One must remember that the United Gas Transmission System of the Soviet Union was built on the basis of two sources of natural gas reserves – major fields of West Siberia and those of Turkmenistan, Uzbekistan and Kazakhstan, which then made up part of the Soviet Union. Central Asian gas is delivered to consumers via a system of transit pipelines named Central Asia-Centre (CAC), built in 1967–1985 through Turkmenistan, Uzbekistan and Kazakhstan up to Alexandrov Gai compressor station at the Kazakhstani–Russian border. CAC’s throughput capacity does not exceed 45-55 bcm per annum at separate sections. Gazprom transits Central Asian gas to the Russian and export markets as well as acts as operator of Turkmen gas transit across Uzbekistan and Kazakhstan. In order to secure transmission capacities for Turkmenistan, Uzbekistan and Kazakhstan gas transit, Gazprom has developed the Priority Actions Program targeted at de-bottlenecking the CAC system.

Table 5: Summary of Gazprom activities/relations with Central Asian states

	JV or PSA	Transit or Supply Agreements
Kazakhstan	Gazprom & KazMunaiGaz established a 50/50 JV KazRosGaz to market Kazakh gas internationally	Medium-term transportation contracts for Russian and Central Asian natural gas through Kazakhstan from 2006 to 2010
Turkmenistan	Upstream JV or PSA dependent on geological assessment	April 2003 a 25-year gas supply agreement was signed from 2004 to 2028 with OAO Gazprom and Turkmenneftegaz in charge of its implementation. GazpromExport signed a contract for Turkmen gas supplies to Russia for same period.
Uzbekistan	In mid-April 2004 a USD15 million PSA was signed securing 5 bcm of exports from Uzbekistan annually. Gazprom is rehabilitating gas production from the Shakhpakhty field under a PSA. In December 2006, the parties agreed to do a feasibility study and PSA on fields in the Ustyurt region.	2003 Gazprom and Uzbekneftegaz agreement to long-term purchases of Uzbek gas from 2003 to 2012. In mid-2003 the Uzbek Government appointed Gazprom as operator for all its gas exports. In September 2005, Gazprom and Uztransgaz signed an agreement to transport gas through Uzbekistan from 2006-10 via the CAC and Bukhara – Ural gas pipelines.

Note: Preparations are underway for JVs to be created between Russia and Kyrgyzstan as well as Russia and Tajikistan. Two geological survey licenses have been obtained for blocks in Tajikistan’s Dangarinsky and Rudaki areas with 35 bcm and 30 bcm in estimated gas resources, respectively.

Although it is perhaps natural for Gazprom to rely on the principles on which the company and infrastructure was based, there are clear geopolitical repercussions to its actions. Furthermore, the long term contracts and alliances being formed with Central Asian countries have allowed

Gazprom to delay restructuring by limiting non-Gazprom production while at the same time effectively removing Central Asian gas as a potential competitor on export markets.

While Gazprom points to the lack of capacity in the West Siberian part of its pipeline system, such that it is unable to provide access for potential domestic flows from the independents, there is spare capacity in the systems connecting Central Asian Republics and it is in Gazprom's interest to lock them up before other outlets are built. In this way, Gazprom literally buys time to delay production from capital-intensive and increasingly expensive reserves in Yamal and the Barents Sea. However, the policy of buying additional volumes only postpones addressing the more fundamental problem of how to compensate for the decline at its major fields, and the need to reform the Russian gas sector.

This strategy is reflected in Gazprom's website:

> *As the groundwork for sustainable gas supply in the future, Gazprom is looking to tap into new fields in Yamal and the offshore fields in the Barents and Kara Seas. All these areas have exceptionally challenging climatic and geological conditions. Gas will cost much more to extract there compared to other regions. Meanwhile, Gazprom is keen to use the huge gas resources of Central Asia to optimize its gas supply for export. In 2006 Gazprom transited around 56.8 bcm of gas originating in Central Asia and Kazakhstan.*

This strategy is not without its costs. The Central Asia pipeline system will need major investments to refurbish and increase capacity. The Central Asia-Centre (CAC) pipeline network made up of 5 different lines was designed and built over the period 1966-1987 with an overall design capacity of about 90 bcm/y. The lack of maintenance and investment over time has almost halved the capacity of the system. If Russia intends to increase Turkmen exports to 80 bcm/year, not to mention the expected increase in exports from Kazakhstan and Uzbekistan, major refurbishment and expansion to the CAC system will be necessary.

Talks between Gazprom CEO, Alexei Miller, and the then Turkmenistan President, Niyazov, in early April 2004, raised the idea of new pipeline construction within the framework of the plans for CAC refurbishment and expansion. In May 2007, the Presidents of Russia, Kazakhstan and Turkmenistan signed a widely-reported Declaration on the Construction of the Caspian Coastal Pipeline, supplemented in December of the same year by a Trilateral Agreement on Cooperation in the Construction of the Caspian Coastal Pipeline. It is to bring gas from western Turkmenistan and from Kazakhstan northwards to join the Central-Asia-Centre lines in Kazakhstan. Gazprom announced, following a meeting in Ashgabat in July 2008, that the capacity of the Caspian Coastal line could be expanded to 30 bcm/y. The pipeline would be built by Turkmengaz, KazMunaiGaz and Gazprom.

Evolution of Gas Flows from Central Asia

In the past annually some 50 bcm of Turkmen gas was transited through the Gazprom system to supply Ukraine. Long term contractual agreements discussed in 2003 for Russian imports of Turkmen gas (of up to 80 bcm/year from 2009-2029) directly affected this arrangement – in terms of control and ownership of the gas. The agreement called for Russia to purchase 5-6 bcm in 2004, rising to 6-7 bcm in 2005, to 10 bcm in 2006, up to 60-70 bcm/y in 2007 and up to 70-80 bcm/y over the period 2009-2028. The sharp increase in 2007 was related to the expiry at the end of 2006 of the 36 bcm/y supply agreement between Turkmenistan and Ukraine. The price Russia agreed to pay for Turkmen volumes to 2006 was set at USD44/tcm, with 50% paid in goods and services in order to match the price paid by Ukraine for these volumes. Since 2006, the price paid by Russia for Turkmenistan gas increased substantially. By the second half of 2008 the price was already up to USD 150 per thousand cubic metres, and this was set to increase again for 2009.

From a consumer's perspective, Russia's long-term contracts with Turkmenistan increases Russia's dependence on Central Asian gas to meet its export obligations to the near and far abroad. From a Russian perspective, however, locking up these volumes of gas, even at higher prices, can be seen also as a way to limit non-Russian supplies moving east to China at a price lower than an acceptable Russian negotiated price for gas supplies to China. However, as Russia has been trying to effectively fix a floor price for exports to China from either Russia or Turkmenistan, China has managed to negotiate a separate deal with Turkmenistan.

Turkmenistan appears to have positioned itself well between Russia and China – playing one off the other to get the highest price it can for its gas moving east to China and west to Russia. For the time being it would seem that Russia's control over gas supply from the Caspian region has been weakened – as has its negotiating position vis-à-vis China over the price of Russian or Russian-controlled Turkmen volumes of gas exports in the future.

Russia's ability to control Turkmenistan's gas exports would also appear to be linked to Russia's plan to develop East Siberia. It is through the revenues from exports to China that Russia will find the wherewithal to accomplish the major infrastructure and social programs involved in its East Siberian development plan. This was reflected in remarks by the Russian President Dmitry Medvedev in mid-September 2008 at the Valday Club discussions when he reassured his audience that Russia had enough supplies to satisfy both European and Asian markets. He said that:

> *Russia planned on developing its energy co-operation with Asian countries but not to the detriment of its European direction. Without diversification the development of the eastern part of Russia won't happen.*

Conclusions

Russia's strategy in Central Asia has evolved over the last two decades, reflecting its continued interest in the natural resources of some of the Central Asian states. Russia's involvement and investment in the region has grown, and its focus has shifted from a position focused more on capturing Central Asian resource rent to one concentrating more on commercial control and limiting competition by other potential players.

The pace of Russian involvement in Central Asia has quickened as interest has grown from other international players, and in particular from China. China's concerted moves to increase in presence in Central Asia has had a number of effects on Russia: not only has it challenged Russia's position in the region, but it has also come with a major price tag in terms of higher prices paid for Central Asian gas exports, as well as lost or reduced potential revenues from Russia's own eastern exports and an East Siberian development program needing to be financed more fully from Russian government coffers.

Nonetheless, as its strategy evolved, Russia has been able to draw upon several advantages and levers:

- Russia's common history and cultural affinity has allowed it to act quickly in its dealings with Central Asian states. The relative lack of transparency and legal security is less of a deterrent to Russia and Russian companies than it is for shareholders and lawyers of western oil majors.
- Russia has been able to raise the price it pays for Central Asian gas resources as it has raised prices to Ukraine and other CIS countries keeping this gas in its control. And these

higher prices have helped Russia in its negotiations on its (and Turkmen) gas exports to China.

- Russia's position on the status of the Caspian Sea has contributed to the risks involved in westward-oriented investments in the region given the legal uncertainty it generates about the possibility for trans-Caspian pipelines. The recent instability in Georgia – along proposed pipeline routes – adds further uncertainty to these midstream investments.
- Russia has the advantage of existing, fully amortised infrastructure bringing Caspian energy exports to international markets. The Russia-Turkmenistan-Kazakhstan announcement of plans to build the Coastal Caspian gas pipeline and the plans to rehabilitate and modernise the main Central-Asia-Centre pipeline system reflect Russia's determination to ensure that routes through Russia remain the main export channel for Caspian gas.

China and Caspian Gas

- China has quickly become an important player in Central Asian energy markets, garnering attention with significant investments and rapid construction of new oil and gas pipelines.
- Oil imports from Kazakhstan promise to be a significant, though relatively small source for China, whereas gas from Turkmenistan stands to feed a large fraction of Chinese demand.
- A face-value reading of China's current projections for supply and demand would seem to indicate that China would not require pipeline gas imports beyond Turkmenistan's promised volumes, but there remain uncertainties over future supplies and demand, and Russian gas may well play a large role.
- Trends in gas demand—and thus the need for imports from Russia and the Caspian region—will depend in large part on the evolution of China's regulatory system, from its current complex and sometimes contradictory strata of administrative decrees and pricing formulas to a more coherent and market-based system.

Overview

East of Central Asia lie established and growing energy importers – Japan, Korea, Chinese Taipei, and an emerging importer—the People's Republic of China. Among them, only China is contiguous with landlocked Central Asia. Driven by its developing, but already huge and globally integrated economy, China's oil and gas consumption (and imports) provide Central Asia with a huge market opportunity. This reflects the shift in the centre of gravity of world economic power towards Asia, with China in its centre. Russia too senses a market opportunity, but its concern about competition for influence in Central Asia from the "West" is now joined by vigilance at the rise of the "East".

China has become much more active in Central Asian energy markets in recent years, bringing in investment and beginning to take BTUs back home. It is eager to participate in upstream activities, and Central Asian nations have been more welcoming than many other nations – although they are still quite wary of coming too strongly under the influence of yet another large neighbour. China has sought to soften the shock of its strong showing in energy and economic affairs through diplomacy, aid, and leadership in regional multilateral activities, notably the Shanghai Co-operation Organisation. But the thinly populated countries of Central Asia remain alert to their populous neighbour.

China's first big success, of course, has been in Kazakhstan, where CNPC/PetroChina has invested in oilfields and pipelines. The first phase, a cross-border link through Alashankou, delivered 85 kb/d to China in 2007 (see annex). The link between the eastern and western sections of the pipeline is expected to be completed in 2009, connecting the north Caspian shore to China. When the project is completed, it would have the capacity to bring 400 kb/d into China, less than 5% of anticipated total demand, but still a significant contribution.

China eyes Central Asian and Russian gas supplies

The Caspian region is expected to play a much larger role in China's overall gas picture than for oil. Expanding the use of natural gas has long featured in China's energy strategy, and access to Caspian gas is an increasingly important element in achieving that aim. Projections from the

Chinese government, oil companies, and analysts vary, but in rough terms China expects to use about 200 bcm per year of natural gas in 2020. If the recent pace of domestic discoveries and development continues, some Chinese sources believe the country could produce up to 140 bcm per year (others are more pessimistic), and that in the longer term about one-third of the natural gas consumed in China would be imported. Coalbed and coal-mine methane development has the potential to augment natural gas supplies by 10% or more. The current and planned LNG terminals along China's eastern seaboard that now have or may soon have firm supply commitments would provide collectively about 20 bcm per year, leaving a gap of at least 40 bcm per year in 2020 that would have to be met by pipeline imports.

Turkmenistan may well become China's first source of Central Asian gas. In 2007, China signed a 30-year sale and purchase agreement with Turkmenistan to import 30 bcm per year, and then quickly reached deals with Turkmenistan, Uzbekistan and Kazakhstan to put the necessary pipeline in place. Then, on the occasion of President Hu Jintao's visit to Ashgabat in August 2008, the Turkmens confirmed an offer, first raised in Beijing during the Olympics, to provide 40 bcm per year. The agreement calls for first volumes to be delivered at the end of 2009, and for 30 bcm per year to be delivered to China by 2012 (additional details on the Turkmenistan-China pipeline project are included in the annex). Part of the gas will be sourced from a field being developed by CNPC on the right back of the Amu Darya River in Southeast Turkmenistan. Based on a 2007 production-sharing agreement, CNPC has started exploration and construction of gas processing facilities. If Turkmenistan is able to provide these volumes by 2020, then China would not need to rely on any other suppliers. This seems unlikely to happen, however, since uncertainty over domestic supplies and demand could lead to a significantly greater need for pipeline and LNG imports. At the very least, alternative suppliers would provide China with valued leverage in negotiations.

In August 2008, CNPC and KazMunaiGaz agreed to build a gas pipeline that will serve as a link in the delivery chain from Turkmenistan, and serve gas transport needs within Kazakhstan as well. Flows of Kazakh gas to China are expected to be small, however.

Figure 3: China's evolving natural gas pipeline network

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

China has sought to bring in Russian gas, but progress has been slow, and the apparent success of the Turkmen deal may give China confidence to remain firm in negotiations. China and Russia both profess to be frustrated with the slow pace of action on their 2006 agreement to send a total of 60 to 80 bcm per year of gas to China, first from western Siberia (providing half of the total volume), then from Kovykta and Sakhalin. Negotiations stalled over prices; the initial agreement linked the gas price to oil prices, and with rising oil prices the Chinese side has backed off. While both sides occasionally announce an imminent conclusion to discussions (Gazprom said in September that Russian gas could reach China in 2013 or 2014), and while there have been some reports of survey work for an Altai pipeline to bring West Siberian gas to Xinjiang, there are few signs of the rapid progress that China has shown itself capable of. Moreover, Russian plans for the Kovykta gas supplies have evolved, turning from the eastward export markets originally envisioned by TNK-BP to energy for development of the Russian Far East. It is not clear how a possible takeover of the Kovykta field by Gazprom would affect the pace of negotiations. In this setting, China appears to be using their deal with Turkmenistan, which reportedly is at a price lower than that being charged to Russia for Turkmen gas, to signal to Russia that if it fails to move towards China on the issue of price, then China is capable of seeking pipeline supplies from elsewhere. CNPC is reportedly beginning to draw up plans for a third West-East gas pipeline, which would be required to bring in West Siberian gas if Turkmenistan fills the 40 bcm per year maximum design capacity of the second West-East pipeline.

From Gazprom's viewpoint, the Chinese market is not entirely reliable. Uncertainties regarding prices and lack of coherence in the regulatory system inject uncertainty into demand, and the Russian side may be seeking an opportunity to invest in gas-using facilities in China in order to guarantee a market for their deliveries. Like Russia, however, China is reluctant to allow foreign investment in its energy sector, and the stalemate shows no sign of a quick resolution.

China's regulatory landscape hinders growth in gas demand

Despite continued high-profile calls to ramp up gas use to meet goals for economic growth, greater energy efficiency and better environmental performance, China's regulatory and market environment appears set to keep demand from rising fast because domestic gas supplies cannot keep pace with consumption. In August 2007, the National Development and Reform Commission issued a policy directive regarding use of natural gas. This recognised four different categories of customer, and assigned priorities to each. Residential and urban users were awarded highest priority, industrial fuels uses (for boilers and kilns) were permitted, power generation was limited, and new petrochemical feedstock uses were prohibited. Natural gas use is growing faster than that of other fossil fuels. This policy is intended to ensure that gas goes to uses that maximise benefits to human health and the local environment. Combined with pricing of gas, this administrative guidance prioritises consumers and thus may tend to dampen growth in gas demand.

Under this policy, households and commercial buildings are favoured in terms of planning and allocations and they are also the most protected against market prices. Gas prices to city users have been rising, to be sure, but they still enjoy substantial subsidies. This means that the gas brought in from such great distances, and thus so expensively, needs to be supported either through much higher prices to other classes of users or to appropriations organised by the state. Under these circumstances, too, there is a limit to the extent that consumption in this sector can grow.

Power generators are allowed to use gas except in areas close to coal reserves. Even were gas supplies larger, however, the limited ability of power generators to reflect the full cost of fuel in the price they receive for electricity would limit the attractiveness of gas-fired power generation. Despite rising coal prices and more-stringent application of environmental controls, coal-fired power remains much cheaper than gas-fired power. Until the utility regulatory landscape changes to allow gas-fired generators to be paid for the value of the peak power they provide, growth in demand for gas from this sector may be weak.

Gas is a superior feedstock for chemical synthesis processes that in China frequently rely on coal, e.g., production of methanol and ammonia, the latter mainly destined to become fertiliser. Switching to gas is a quick path to higher energy efficiency and reduced pollutant emissions, but only those plants that were already in operation, under construction, or approved at the time the policy went into force are eligible to receive gas supplies. Perhaps more than other users, petrochemical manufacturers would be able to absorb the rising costs of natural gas, but at the moment they are not allowed that opportunity. Some industrial customers who use gas as a fuel are also able to absorb that cost, such as makers of ceramics that need natural gas to produce their higher-quality products. As a boiler fuel it is certainly cleaner, but coal can get the job done as well.

Implication of domestic gas market situation on perceived urgency for pipeline gas imports

Administrative directives on flows of gas and price controls that limit growth in gas demand may contribute to a sense among China's gas importers, and the government that seeks to guide them, that they have time and room to manoeuvre in their negotiations with potential suppliers. Moreover, China's dependence on gas is much lower than in many developed countries, so, for now at least, there are alternatives; if gas does not become available, there is still a good deal of coal to go around. The Chinese have also demonstrated that they can move quickly to conclude deals, and to put required infrastructure in place, casting them as reliable customers able to carry out agreed actions faster than their rivals. This may further strengthen their confidence during negotiations.

That said, China is operating under some time constraints. CNPC started to lay its second West-East pipeline in 2008. This is set to run parallel to the western portion of the first West-East pipeline up to Gansu, and will then branch off to the south, serving Guangdong and the south-eastern coast, unlike the first one, which delivers two-thirds of its gas to Shanghai. The second West-East pipeline may even feed into power plants in Hong Kong, under the terms of an agreement signed between China and Hong Kong in August 2008 (although Hong Kong's China Light and Power is seeking to bring in gas through a cross-border link to an LNG terminal that would be supplied by BG Group). Currently identified resources in the Xinjiang Uygur Autonomous Region will do little to fill the 30 bcm/y pipeline, with over 9 000 km of main and branch lines; Central Asian and/or Russian gas is required. Plans call for deliveries to Guangdong to begin in 2011.

There are signs also that change may be coming in the crucial area of price regulation. Recently, the Chinese government has shown a willingness to gradually ratchet up energy prices in other sectors to reflect global market conditions. Moves to raise oil product and electricity prices in the sensitive period before the Olympics surprised some, given deep-seated worries about inflation, but apparently were intended to keep supplies flowing. Now there are reports that similar moves are being considered for natural gas as well, to replace the current unwieldy production- and transmission-cost-based system with a more coherent market-based pricing system. Pressure to do this will increase as more gas from different sources enters the system. Users in Shanghai, for instance, now pay about USD 9 per Mbtu for gas from the West-East pipeline, expected to rise to about USD 12 per Mbtu by 2015, or about the same level as that from the second West-East pipeline. This will be mixed with some gas from Sichuan (domestic prices average near USD 5 per Mbtu), and with LNG. Petronas has signed a contract to deliver gas to Shenergy and CNOOC's terminal for USD 6 to 7 per Mbtu, but additional volumes going to other planned terminals in the Shanghai region would likely pay far higher prices. The central and local governments will be keen to continue protecting sensitive, prioritised customers, while at the same time allowing average prices to rise to levels sufficient to keep new supplies coming in.

Iranian Gas: a Reliable Medium-Term Supply Source for Europe?

- Iran has huge reserves of gas, ambitious plans to increase production, a wide range of export possibilities and (historically) unusually good relations with all its neighbours.
- But it is unlikely in the medium term to have spare gas for export. Domestic demand and enhanced oil recovery (EOR) requirements are likely to soak up most of the increased production.
- In any case, development plans will continue to be constrained by international sanctions and western pressure, as well as by domestic political uncertainty.
- Iran has signed up to extensive long-term export commitments including for LNG, but without additional investment and technology (especially in LNG) these targets are unlikely to be met. They may see a political benefit in becoming a major supplier to Europe, but they would have to sacrifice domestic priorities to do so.
- There is however some limited scope for swaps in both oil and gas with Iran's Caspian neighbours, which would be profitable for Iran and useful – at the margin – for both the landlocked Caspian states on one side and their overseas customers on the other.

Note: The information in this paper has been drawn from open sources. It is not hard to come by but is often unclear, and data can be contradictory. It is our best assessment of Iran's current position, but readers may well have access to information of their own, and the Secretariat would welcome any comments or clarifications.

Introduction

Iran has over 27.5 trillion cubic metres of gas reserves. Current gross gas production is about 145 bcm/y. In recent years, about 65% of total production has been marketed (for power, petrochemicals, industry and residential). Consumption is rapidly mounting. The mean growth during the years 2000-2007 was 8.2% pa. Production was increasing slightly faster, at 9% pa during the same period.

About 18% of gas production is used for enhanced oil recovery; about 15% is lost to flaring. A small and variable quantity is available for export (to Turkey). Meanwhile, development projects in both associated and non-associated gas abound. Three major trunk lines are under construction. The target for peak gas production in 2017 is 500 bcm/y, though this would require nearly a doubling of average growth which could be very optimistic.

Current oil production is 3.87 mb/d (just above Iran's OPEC "quota"). Meanwhile, the Iranian oil fields are maturing[4]. The government has not made a major oil find during the last decade – only in the Markazi province of central Iran are there 45 larger and smaller fields to develop[5].

The hydrocarbon sector needs modernization and upgrading. The government plans to attract some $200 billion in domestic and foreign investment by the end of the 20-year strategic plan in

[4] The onshore and offshore fields experience an annual decline of 8 and 13%, respectively. This is equal to 350.000 barrels.

[5] Sarmayeh 01.09.2008: *45 meidan-e nafti-wo gazi-e manateq-e markazi hanuz touse'e nayafte and (45 oil and gasfield in markazi province have not yet been developed)*

2025[6]. This is unlikely to be realized unless current domestic and international political issues are settled.

Sanctions and the Iranian response

- ***Sanctions***

The 1996 Iran-Libya Sanctions Act (it was renamed the Iran Sanctions Act ("ISA") after the law's Libya sanctions were removed in 2006) requires the US President to impose sanctions against companies (foreign or domestic) that make any investment of more than $20m that directly and significantly contributes to the development of Iran's petroleum resources. Because US firms are prohibited under other laws from investing in Iran's petroleum sector, all of the investments that would potentially trigger sanctions under ISA involve foreign firms. For example, the State Department reported in July 2008 that it would review whether StatoilHydro was in breach of sanctions.

- ***Nuclear impasse***

Iran has so far refused to yield to international pressure over the country's nuclear programme. The impasse has led to sanctions from the UN Security Council, which put travel restrictions on several senior Iranian figures. Financial transactions to and from Iran, for example through Bank-e Melli, have also been restricted.

- ***Political risk***

A number of foreign partners are backing out of Iran. In 2008 Total, StatoilHydro, Shell and Repsol, who all are engaged in various phases of the South Pars gas development, signalled that they would not invest further in the country for the present. Christophe de Margerie, Total's chief executive, hinted that the political risk was too big to continue investing[7].

- ***Orientation eastwards***

Meanwhile Iran is forging ties with energy companies elsewhere, notably Russia, India and China. SINOPEC signed in December 2007 a $2 billion deal to develop the giant Yadavaran oil and gas field[8]. Under the agreement, China will buy oil and 13.8 bcm of LNG a year for 25 years[9]. Gazprom signed in July 2008 a MoU with NIOC, describing a full package of projects to develop oil and natural gas fields, build processing facilities and transport oil from the Caspian Sea to the Gulf[10]. Gazprom has already invested in phases II and III of South Pars, and agreed in February to develop more phases[11].

Current developments in the gas sector

Current production is just enough for domestic consumption under normal circumstances, with exports to Turkey balanced by imports from Turkmenistan. Last winter, when severe snow coincided with a dispute with Turkmenistan over gas import pricing, factories and government

[6] Shana 11.06.08: *A $200 bn Investment in NIOC projects: Official*
[7] Financial Times 09.07.08: *Total steps back from investing in Iran*
[8] The field is expected to produce 85.000 b/d in four years and a further 100.000 b/d in the following three years.
[9] International Herald Tribune 10.12.07: *Sinopec to develop oil field in Iran*
[10] RIA Novosti 15.07.08: *Gazprom, Iran sign oil and gas cooperation memo paper*
[11] Reuters 19.02.08: *Gazprom, Iran agree new large energy projects*

offices were forced to close[12]. The current five year plan aimed to raise production to 290 bcm/y by 2010[13], though this now looks unrealistic. The development and marketing of gas on the world market remains central to the government's 20-year strategic plan. But the continuous delays in the development projects undertaken, and the weight of international financial sanctions, raise doubts about whether the country will be able to reach these goals.

- ***Rising consumption***

At the same time, domestic demand for natural gas in Iran is rising steeply – estimated at at least 7% per annum for the foreseeable future. There are heavy subsidies in the domestic market. Gas is used increasingly for power generation, not least to reduce dependence on imported fuel oil. Current plans for electricity generation would require at least a further 15 bcm/y by 2012 and as much as 48 bcm/y by 2013. There are ambitious plans for expansion in the petrochemical sector, which may double capacity by 2011.

- ***Enhanced Oil Recovery***

The need for injections in Iran's maturing oil fields is about to increase sharply – estimates from Facts Global Energy see the need rising from 30 bcm/y in 2008 to 115 bcm/y in 2015. There is already evidence of this: NIOC corporate planning manager, Abdol Mohammad Delparish, tells of plans to inject 40 bcm of gas in oil fields in 2008[14]. Iran announced in September the commissioning of the 504 km IGAT-5 pipeline from Assaluyeh to the oilfields of Khuzestan to inject gas from South Pars phases VI-VIII into the giant Aghajari field.

- ***Direction of the hydrocarbon sector***

The ties between NIOC and the political institutions are tight. The Energy Minister is at the same time chairman of NIOC whilst deputy ministers serve as executives in the NIOC subsidiaries. After the election of President Ahmadinejad in 2005, several managers at the higher and medium level, close to ex-president Rafsanjani, were replaced with figures close to the new President. Foreign oil executives have complained that disruptions in management have affected projects[15].There are disagreements between different government bodies on priorities in the gas sector; and the choice of domestic contractors with low level of expertise, for political rather than economic motives, may also explain project delays.

Gas Trade

- ***Gas Imports***

Currently, Iran is a net importer of gas. Tehran received 6.2 bcm in 2007 from Turkmenistan through the pipeline that runs from the Korpedzhe field to Kurt-Kui in the North East. The Turkmen supply has been interrupted several times amid wrangling over prices. When the deliveries resumed in 2008, Iranian authorities would not disclose how much they are now paying[16]. Iran also imported 0.2 bcm from Azerbaijan in 2007 and has expressed an interest in additional gas import from Phase II development of the Shah Deniz offshore gas field. According to Stratfor, Tehran and Baku are discussing the export of 12 bcm of natural gas per year from 2012[17]. Naftiran has a 10% stake in the Shah Deniz field.

[12] Financial Times 24.06.08: *Fields of dreams: How sanctions hinder Iran's gas ambitions*
[13] La Mission Economique Francaise en Iran: *L'amont pétrolier et gazier en Iran*. Tehran, mai 2007.
[14] Shana 11.06.08: *A $200 bn Investment in NIOC projects: Official*
[15] Interviews, Tehran, 2007
[16] Reuters 05.05.08: *Iran to import 30 mcm of Turkmen gas daily*
[17] Stratfor 28.05.08: *Iran: The Natural Gas Problem*

➢ ***Swap and transit deals***

Iran is involved in gas and oil swap deals around the Caspian, an activity which according to official plans is expected to increase over the coming years:

- Since late 2005 Iran is engaged in a gas swap deal with Azerbaijan for the Azeri republic of Nakhichevan. As stipulated in the 25-year contract, Azerbaijan delivers 80 mcm/y to Iran, who then delivers 85 percent to Nakhichevan. The delivery is due to rise to 402.5 mcm/y in the period 2009-2024, of which Iran will transfer 350 mcm/y to Nakhichevan.
- Beginning the first of October, Iran will supply neighbouring Armenia with 1 bcm annually[18]. In exchange, Armenia will supply Iran with electricity (3 kWh per cubic metre of gas). Gazprom is to invest $200 million in an Iranian-Armenian pipeline[19]. Some commentators have suggested that this would reduce the need for Russia to supply Armenia via Georgia.

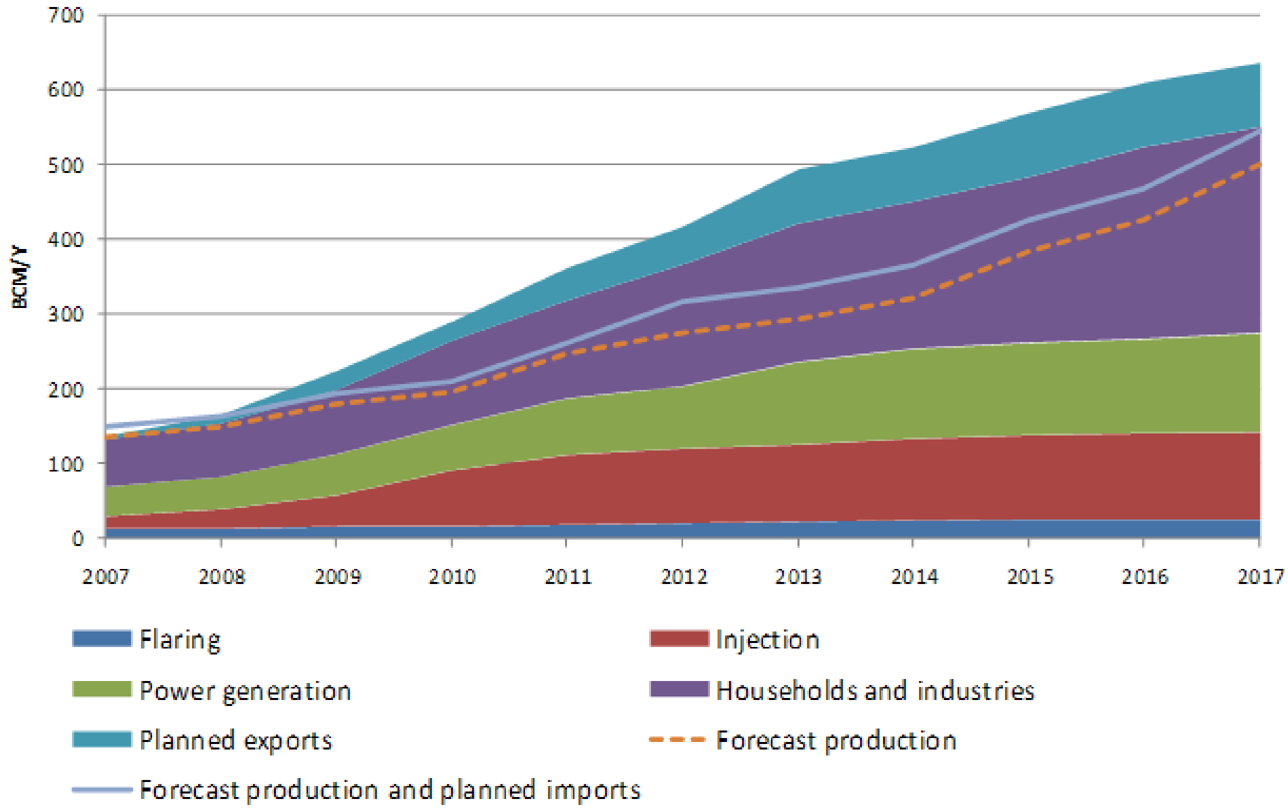
A number of other swap projects are under consideration:-

- Iran is currently conducting studies to build a north-south gas pipeline that will be used for swap deals from Iran's northern neighbours to the Oman Sea. The pipeline, which will stretch from Sarakhs at the Turkmen border to the southern port of Jask, will have a capacity of at least 12 bcm/y[20].
- Seasonal swap deals north-south: Iranian need for energy is low in summer and high in winter. Other Gulf countries: high in summer, due to high electricity demand for air conditioning. Akbar Torkan, head of Pars Oil and Gas Company (POGC) and deputy petroleum minister for planning, is said to be drawing up a seasonal swap proposal.
- The MoU signed with Gazprom in July implies possible gas swap deals with Iran as well as a partnership in the IGAT-7 pipeline from Assaluyeh to Iranshahr, which would eventually be connected to the IPI pipeline (see below) delivering Iranian gas to Pakistan and India.
- Iranian officials are also considering using the planned pipeline from Sarakhs to the port of Jask to deliver Turkmenistan gas to Pakistan and India[21]. If realized, it would displace the proposed TAPI (Turkmenistan-Afghanistan-Pakistan-India) pipeline that has been delayed for years due to instability in Afghanistan. With a capacity of 12 bcm/y the pipeline could in theory also transport gas from Kazakhstan and Uzbekistan as well[22], though there must be serious question as to whether Turkmenistan, Kazakhstan or Uzbekistan will have spare gas capacity at that time.

Putting together all the forecasts, it seems clear that in the medium term Iran will not be able to satisfy all its potential domestic demand and have spare gas for exports. Indeed depending on their ability to moderate demand and develop alternative fuels, Iran may have to import even more significantly by 2013.

[18] Shana 29.08.08: *Saderat-e gaz-e Iran be Armanestan az mah-e mehr aqaz mi-shavad* (Iranian sales of gas to Armenia begins in Mehr month)
[19] Fars News Agency 06.07.08: *Gazprom to Invest $200 mln in Iran-Armenia Gas Pipeline*
[20] ISNA (Islamic Student's News Agency) 08.06.08: *Iran to deliver gas from northern neighbors to Oman Sea*
[21] Presentation by Akbar Torkan, chief executive of Pars Oil and Gas Company (POGC) and Deputy director of planning, Iranian Ministry of Oil: *Iran Natural Gas Reserves, Production & Export Possibilities*
[22] Tehran Avenue, August 2008: *Construction of Sarakhs – Jask gas pipeline on agenda*

Figure 4: Iran gas production, consumption and exports



➢ ***Iranian gas export deals.***

Meanwhile, Iran has signed a variety of contracts and MoUs to supply gas, mainly to its regional neighbours. Few of these have yet been implemented, and it is far from clear that Iran will have enough spare gas production to supply more than one or two.

- Iran-Turkey: Iran is supposed to supply Turkey with 9 bcm/y, but the deal has been affected by several interruptions in Iranian delivery. Annual supply has varied widely since operations started in 2003, averaging about 4.5 bcm/yr overall. Nevertheless, when the Azeri-Turkish pipeline was damaged in August 2008, Turkish imports of Iranian gas were increased briefly to compensate[23].
- Iran signed in 2008 a contract with Oman for the supply of 10 bcm/y by pipeline. The deal also included joint development of the Kish and the Hengam gas fields. Some of this could be processed at Oman's Qalhat LNG plant. Talks have just been resumed. Oman has announced it will fund the project entirely.
- Iran is close to a deal with UAE's Crescent Petroleum for the supply of 6 bcm/y from the offshore Salman field. Iran and Crescent have been locked in a dispute over the price since 2006, but the company expects imports to start by the end of September[24]
- Bahrain signed in late December 2007 (during a visit by President Ahmadinejad) a MoU to buy 10 bcm/y of Iranian gas[25].

[23] PressTV 14.08.08: *Turkey ups gas imports from Iran*
[24] Reuters 19.06.08: *UAE's Crescent sees Iran gas imports in 3 months*

- Kuwait has been in talks with Iran to import gas through a prospective undersea pipeline. The amount has not yet been specified[26].
- Iran signed in October 2007 a MoU with Syria to transfer gas via the Tabriz-Ankara pipeline. The deal implies a transfer of 3 bcm/y from 2009[27], during the summer months. The transfer will be stopped during winter due to high Iranian demand.
- Iran-Italy: Swiss energy company Elektrizitäts-Gesellschaft Laufenburg AG (EGL) signed in March a contract for delivery of gas via a pipeline scheduled to be completed in 2012 (the Trans-Adriatic pipeline, TAP). The contract implies that Iran will sell 5.5 bcm/ y through the existing Iran-Turkey link for a period of 25 years, for EGL's power plants in Italy.

Table 6: Iranian gas export contracts

Destination	Amount (bcm/y)	Delivery start	Field	Status
Turkey	9/ 20 (South Pars phase 22, 23, 24)	Started 2003/ MoU signed in 2007	Khuzestan fields / Turkmenistan (?) Phase 22, 23, 24, South Pars	Significant shortages in Iranian deliveries
Armenia	1	Reportedly October 2008	Possible Sarakhs	Delayed, was to be started in March 2008. Diameter of original pipeline cut in half.
Oman	10	Unknown	Kish	Delayed; deal for import from South Pars signed 2006
UAE	6	September 2008 (expected, delayed since 2006)	Salman	Development delayed
Bahrain	10	2009-2015	South Pars	Delivery start unknown, probably close to 2015
Syria	3	2009	Unknown	Gas only to be exported during summer due to high Iranian demand in winter
Italy (for EGL - Switzerland)	5.5	2012	South Pars	Pipeline not finished
Pakistan/ India	22	2013	South Pars	Pipeline (IPI) delayed.

[25] IRNA (Islamic Republic News Agency) 26.12.07: *Iran, Bahrain ink MoU on mutual cooperation*/ PressTV 27.05.08: *Bahrain mulling gas imports from Iran*
[26] Reuters 17.06.08: *Kuwait in advanced talks "to import Iran gas to meet growing demand"*.
[27] Tehran Times 05.02.08: *Iran to expand gas exports to Asia, Europe: spokesman*

➢ *A role for Iran in Nabucco?*

These commitments total about 45 bcm/y by 2012 and a further 22 bcm/y soon after. It looks unlikely that there would be enough production capacity also to allow Iran to be a serious candidate to supply gas for Phase I of the Nabucco project, although taking additional Iranian gas could have attractions for Turkey, and, absent Iran's international isolation, they would have an interest in helping to develop Iranian capacity. Over half of Turkey's demand for natural gas is today met by Gazprom[28].

In September 2007 state-owned Turkish upstream operator Turkiye Petrolleri Anonim Ortakligi (TPAO) signed a deal to develop three phases of Iran's South Pars development, and has the option to transport the Iranian gas back to Turkey[29]. The Turkish-developed blocks would produce 20.4 bcm/y[30]. The agreement includes plans for two pipelines – one of these being the IGAT-9 pipeline - that would eventually be connected to the Nabucco pipeline in Erzurum. The pipelines' capacity would be 30 bcm/y[31] and would be linked to the Iranian east-west pipeline system. This would allow Turkmenistan gas to be shipped to Europe through Iranian territory, if production is substantial enough. However, although the project is still on the table, President Ahmadinejad's visit to Istanbul in August does not seem to have been enough to overcome Turkey's political caution.

On their side, the Iranians make no secret of their willingness to supply the Nabucco project. Even though it is hard, given their domestic requirements, to see Iran finding the quantities necessary in the medium term – and the history of their supply to Turkey hitherto is not reassuring – it is conceivable that were the prospect of supplying Europe sufficiently attractive politically, efforts might be made to divert the requisite quantities from domestic needs. Unless the price negotiated was unusually attractive, it would probably not be the most commercially rewarding use for the gas. On the other hand, it is already clear that political priorities weigh heavily on NIOC.

➢ *Other Iranian pipeline interests*

Iran-Pakistan-India or Peace Pipeline: Would initially carry 22 bcm/y, which ultimately would be increased to 50 bcm, shared half/half India and Pakistan. It would be connected to IGAT-7 from Assaluyeh to Iranshahr, and might further be connected to the Sarakhs-Jask pipeline to supply Turkmen gas, possibly from the Dauletabad field. This would provide an alternative to the TAPI pipeline, and might eventually be an exportation route for gas from Kazakhstan and Uzbekistan. Gazprom has been invited to join the pipeline project, in return for Indian participation in Sakhalin II. Pakistan's Ministry of Petroleum has said construction on their part of the line will begin in mid-2009[32]. But latest reports suggest India and Iran have yet to agree on pricing or on the delivery point for the gas – the Iranian frontier or the Pakistani.

TIT Pipeline: The proposal for a Turkmen-Iranian-Turkish pipeline (30 bcm/y) to link the Dauletabad gas field to Turkey fell away in the mid-1990s once the difficulties of raising international finance for projects in Iran became apparent[33]. For Iran, the planned pipeline had been particularly attractive as it would have maximized the profitability of Iranian gas, which would be swapped for Turkmen gas sent west through the Turkish pipeline system. The Turkmen

[28] The Economist 23.08.07: *Too energetic a friendship*
[29] Financial Times 30.06.08: *Turkish oil Group looks south*
[30] Reuters, 22.08.08: *Turkey-Iran gas deal depends on pricing-source*
[31] Energy Tribune 23.10.07: *Iran/ Nabucco Boosts Turkey's Energy Bridge*
[32] Report by Vedomosti (Russian), cited by Ria Novosti 14,08.08
[33] Olcott, Martha Brill (2004): *International Gas Trade in Central Asia: Turkmenistan, Iran, Russia and Afghanistan*

gas would move into Iran's northern gas pipeline network to supply Iran and its other prospective customers. These arrangements could be revived as part of any Iranian participation in gas supply through Turkey to Europe, but only if Turkmenistan had significant quantities of spare gas and was not supplying the same markets via another route.

- ***Export deals - LNG***

The table below sets out current plans for LNG production from the later phases of the South Pars development and the North Pars field:

Table 7: Iranian LNG projects

Project	Capacity	Original start date/ anticipated	Gas field (South Pars)	Contractor	Market	Status
Persian LNG	10.6 mt/y (7.75 bcm/y)	2010/ 2014, unknown due to uncertainties over contract	SP phase 13/14	NIOC/ Shell/ Repsol	Europe	Shell and Repsol renegotiating deal. Only minor work effectuated.
Iran LNG	8.8 mt/y (6.5 bcm/y)	2010/ unknown. Significant delays expected.	SP phase 12	OMV (Austria) Iran LNG Company, KOA entity Rah-e Sahel is subcontractor	Europe/ India	According to Iran LNG Company is 40% finished. Contractor for LNG train not determined.
Pars LNG	8.8 mt/y (6.5 bcm/y)	2009/ 2011 at earliest	SP phase 11	NIOC/ Total/Petronas	Far East	Total retired from project. Petronas assessing further participation.
North Pars	10 mt/y (7.3 bcm/y)	MoU $ 16 bln signed 2007, no final deal	North Pars	CNOOC	China	Not started

Although all these projects are now seriously behind schedule, some of these quantities seem already to have been committed to certain Eastern customers, sometimes linked to oilfield developments:

- CNOOC China has been invited to develop North Pars (reserves: 2.27 tcm of gas) and build a number of downstream projects including an LNG plant. CNOOC plans to invest $5 billion in upstream and $11 billion in LNG facilities, in exchange for 50% of the production of the field. Each of the four phases of development could have capacity to produce 34 mcm/d. Russia has also shown interest in developing the field.
- India has signed a contract to import 10.35 bcm/y of LNG from Iran LNG (from SP phase 12?), starting in 2009. The period of the deal is 25 years. In turn, Indian company ONGC Videsh Ltd. obtained rights to 20 percent of the onshore Yadavaran oil field, equivalent

to 60,000 bd of crude. The total LNG deal is valued at $35-40 billion[34] but has since been suspended because of a dispute over pricing.

- China is developing a share in Yadavaran, a deal which provides for LNG purchases of 13.8 bcm/y over a period of 25 years, possibly from SP phase 11 or 12. Prior to the deal, Zhuhai Zhenrong Corp. signed in March 2004 a contract to import 151.8 bcm of LNG over 25 years. The company is already a major buyer of Iranian crude.
- Thai PTT has a preliminary agreement with Iran to buy 4.14 bcm/y from Pars LNG for 20 years from 2011.

There is also an arrangement for Poland to develop the recently discovered Lavan Island gas field with reserves estimated at 280 bcm. Polish gas monopoly PGNiG signed in January 2008 a preliminary deal for LNG imports.

Iran's interests in the Caspian

- ***TCP***

Iran would see a successful Trans-Caspian pipeline as damaging its chances of playing a role in East-West transit trade and in certain circumstances of developing its gas exports to Turkey. Iran argues that an agreed legal framework for the Caspian is a necessary condition for the construction of Trans-Caspian pipelines.

- ***Legal position***

During the 1990s, Iran supported a condominium policy for common exploitation of the Caspian Sea mineral resources. Nonetheless, in 1994 it sought a stake in the AIOC consortium in Azerbaijan; this was blocked by some of the other parties. Iran did emerge in 1996 with a share in the Shah Deniz gas field.

Subsequently, however, Tehran proposed a new policy that gave each country territorial waters out to 10 miles for seabed exploration, and another 20 miles for fisheries[35]. Now Iran claims a partition of the Sea that gives 20 percent of the seabed to each of the littoral states[36]. This is not accepted by Iran's neighbours, and the maritime border has not been agreed with Azerbaijan or with Turkmenistan. In 2002, Iranian vessels prevented BP from drilling in contested waters.

Nevertheless, on Iranian initiative, the Caspian littoral states signed a Framework Convention for the Protection of the Maritime Environment in November 2003.

- ***Oil interests***

Iran is beginning to show more interest in Caspian oil. Iranian mineral resources in the Caspian have until today been largely unexploited. However, in an apparent shift in policy regarding the sea, Iran has awarded Brazilian company Petrobras a contract to explore deepwater parts of the Iranian sector. Petrobras is drilling in the Caspian on a buyback contract[37].

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[34] India Express 08.01.05: *Oil diplomacy pays off, India signs mega LNG import deal with Iran*
[35] Granmayeh, 'Ali: "Legal history of the Caspian Sea" in (ed.) Akiner, Shirin: *The Caspian. Politics, energy and security* RoutledgeCurzon 2004, p. 20-21
[36] Namazi, Siamak and Farzin, Farshid: "Division of the Caspian Sea: Iranian policies and concerns" " in (ed.) Akiner, Shirin: *The Caspian. Politics, energy and security* RoutledgeCurzon 2004, p. 230
[37] PressTV 23.08.08: *Iran to develop Caspian Sea energy*

- ***Possible PSAs***

Iran has recently hinted that the government is willing to award PSA-contracts in exploration and development of Caspian resources. In that case, this is the first time in Iranian post-revolutionary history such a contract will be offered. The official explanation is that the exploration costs in the sea are relatively higher than in the Gulf; but it may also reflect the relative lack of technical expertise in Iranian hands. So far Indian and Chinese firms (ONGC Videsh and CNOOC) are in talks with Iran for development of Caspian resources. The question is whether PSAs in the Caspian will pave the way for an amendment to the petroleum law and whether subsequent development projects elsewhere will be open to PSAs. Recent news reports suggest that Gazprom Neft is about to develop North Azadegan field (on the Iranian border with Iraq) under a PSA contract[38].

- ***Swap deals***

Another sign of a pragmatic stance on Caspian Sea legal issues is that Iran has entered several swap deals with other Caspian littoral states. The oil pipeline that links the Caspian port of Neka with refineries in Tehran and Tabriz now has a capacity of 300,000 b/d. With additional pumping stations, the capacity could rise to 500,000 b/d. Chinese SINOPEC signed in 2006 a contract to upgrade the Tabriz refinery, which will double its output to 220,000 b/d (35 ml/d) within 2010. Iran allows tankers to land crude at Neka and sells an equivalent amount at Kharg Island in the Gulf. Existing oil swap deals amount to about 180,000 b/d.

UAE-based Dragon Oil delivers around 32,000 b/d through Neka from the Turkmenistan offshore Cheleken field. Iran has further a 45,000 b/d swap deal with Russian Lukoil. About half of the 200,000 b/d that Kazakhstan ships across the Caspian is landed at Neka.

Tehran expects the total swap volume to rise to 200,000 b/d[39]. It may be limited more by the tanker capacity in the Caspian than by the capacity of the Neka-Teheran pipeline itself, although Iran would doubtless be very happy to take a major role in the Kazakhstan-Caspian Transportation System (KCTS) should it be invited.

Following recent disruptions to the Baku-Batumi rail link, Azerbaijan entered into a 10,000 b/d swap deal with Tehran[40]. The state oil company SOCAR awarded Dubai-based trader Middle East Petrol a contract to export 300,000 tons of Azeri Light Crude via Iran over two-months under the swap system[41].

[38] Fars News Agency 03.09.08: *Gazprom Neft Seeks to Boost Activity in Iran*
[39] Fars news agency 31.08.2008
[40] Fars News Agencym 31.08.08: Azerbaijan Starts Oil Swap with Iran
[41] MEES

India's Energy Demand and its Prospects to Access Central Asian Energy Resources

- India is seeing Central Asia as an important potential energy supplier.
- India has so far not been successful in bidding for Central Asian energy investments
- Regional gas pipelines have made little progress due to a mixture of lack of funding, regional security issues and a difficulty to arrive at a mutual acceptable price of gas

Background

Since the beginning of the new millennium India has reinforced its diplomatic relations with Central Asia with a view to gaining access to the region's energy resources and its strategic positioning in a changing regional landscape. India has pursued its new diplomatic offensive via multilateral and bilateral channels covering various areas like trade, culture, research and military cooperation.

In mid-2005 India, along with Pakistan became observers to the Shanghai Cooperation Organization. Shortly afterwards the Indian Foreign Minister gave a speech in Moscow in which he stressed the Indian view that energy cooperation should be a priority sector for activities undertaken by the SCO and suggested to institute regular meetings of energy ministers with a special focus on regional gas pipelines. Negotiations about obtaining full membership have not advanced since them.

To make its commitment to strengthened Indian-Central Asian energy relations more visible India hosted a roundtable meeting of North and Central Asian oil producers with major Asian oil consumers in late 2005. Suppliers were represented by Russia, Kazakhstan, Uzbekistan, Turkmenistan and Azerbaijan. In addition to India, Asian consumer countries included China, Japan, the Republic of Korea, and Turkey. The round table was aimed at strengthening a uniform Asian approach to stability and energy security. The round table also discussed the proposal for the creation of an Asian Energy Grid covering electricity, oil and gas. One of India's main strategic objectives of hosting the round table was to foster joint investments and bidding in the Central Asian oil and gas sector.

Tajikistan is the closest Central Asian neighbour of India and is of high strategic importance given its borders with Afghanistan. In 2002, the Tajik President and the then Indian Prime Minister signed an agreement to renovate and eventually operate a military base in Farkhar. The base is situated close to the Afghan border. India is also actively investing in hydro-power projects in Tajikistan. These activities are part of India's larger ambition to link Central Asia with South Asia through the creation of an integrated power grid. India's earlier attempts at creating cross-border grid connections with Bangladesh and Pakistan stalled due to political concerns of its neighbours. Increasing the number of participating countries would not only make a regional grid more politically palatable but would also facilitate use of a broader range of power generation capacities and fuel sources in the region. If such a grid proposal would indeed take off it would also strengthen India's economic position in the region.

India's Energy Interests in Central Asia

India's energy interest in Central Asia is more focussed on obtaining equity positions in exploration and production assets than directly linked to meeting India's growing domestic energy demand. This may be different from the objectives of Chinese companies active in Central Asia. India's largest upstream company, Oil and Natural Gas Cooperation (ONGC) has a 20% stake in Sakhalin 1 project and is looking for other opportunities in Russia, including Sakhalin IV.

Despite its diplomatic initiatives India has had relatively little success in pursuing its energy interests in Central Asia. In 2005, India's ONGC established a joint venture company with steel tycoon ML Mittal to co-operate in up-and down stream opportunities in the oil and gas sector in Central Asia. ONGC was hoping to profit from the existing good business relations Mittal has in the region. A second joint venture between the two giants created "ONGC Mittal Energy Services" targeting trading and shipping of oil and gas, including LNG. In the same year the ONGC-Mittal Energy was outbid by the China National Petroleum Corporation (CNPC) in the take-over of Canada based PetroKazakhstan.

The same Indian joint venture has been in open-ended negotiations with state-owned KazMunaiGaz since 2006 for a share in the Satpayev oil exploration block. The Satpayev block is estimated to hold 1.6 billion barrels of oil. However, the national Kazakhstan company is not willing to meet ONGC-Mittal Energy's demand for a 50% share and has stuck to its initial offer of a 25% share for phase I of the project. However, even if India would eventually be awarded a share in the field development, transportation of the crude would be a major logistical challenge for the Indian company. India, through its downstream gas major GAIL, has also been in year-long negotiations with Uzbekistan about investments in the downstream sector that so far have not yielded any concrete contracts.

In August 2008 things started to look better for Indian's Central Asian energy ambitions. ONGC made a successful bid for British-based Imperial energy. ONGC beat Chinese rival SINOPEC in the $2.58 billion take-over. Imperial has assets in Western Siberia and North-Central Kazakhstan. The Kazakhstan assets are expected to produce 10,000b/d in 2008. By 2011 production is expected to reach 80,000 b/d. The reserves in the Western Siberia are estimated at 450 million barrels according to newspaper reports.

Iran-India-Pakistan (IPI) and Turkmenistan-Afghanistan-Pakistan-India (TAPI) gas pipelines

Compared to above-mentioned ambitions, regional pipeline projects such as the Iran-Pakistan-India (IPI) and the Turkmenistan-Afghanistan-Pakistan-India (TAPI) gas pipelines are directly related to India's domestic gas demand. Energy trade between Central Asia and India would require substantial investments in regional infrastructure; especially transport corridors. India's access to Central Asia is hampered by the fact that it relies on third-country transit as it does not have any shared borders.

IPI and TAPI are both passing through Pakistan. The thaw of India-Pakistan relations since 2002 has enabled these ideas to be put back on the diplomatic and business agenda. However, both pipelines have only made limited progress.

In addition to the ongoing security concerns regarding the situation in Afghanistan and Pakistan that calls into question the safety of the pipelines and the physical security of supplies to India, progress on both pipelines is being hampered by unresolved financial issues.

The IPI pipeline is supposed to supply India with 30 mmcm/d (11 bcm/y) in the initial phase, which would become operational at the earliest in 2012. In later years supply could increase to over 45 mmcm/d (16.5 bcm/y). After long negotiations Pakistan and India agreed on an initial price of USD 4.93 per Mbtu for gas from Iran. However, questions over a price escalation clause remain open and no final pricing agreement has been signed.

Pakistan is asking for a transit fee the amount of which is being hotly debated between the two countries. As of spring 2008, press reports suggested that Pakistan was asking for a flat transit fee of $200 million independent from the price of gas. This flat fee would work out to 42 US cents per Mbtu. The Indian side had offered to pay 15 US cents per Mbtu. Negotiations between the two countries are still ongoing. In any case, the price would be above USD 5 per Mbtu before adding the wheeling charges for the use of the pipeline. The two countries have reached agreement on the transportation charges. Pakistan proposed, and India accepted, that a final tariff would be based on the response received to the tender for transportation work through international competitive bidding.

Progress on the TAPI pipeline is also hampered by a number of outstanding issues. Turkmenistan's continued delay in producing a third party certification of its gas reserves is one major stumbling block. TAPI is expected to supply about 40 mmcm/d (14.6 bcm/y) to India by 2014. According to sources in New Delhi the gas reserves certificate was expected to be available during the next TAPI Steering Committee meeting in New Delhi in December 2008. Once gas reserves have been certified agreement on price will be the next big hurdle.

In August 2008, it was reported that Turkmenistan was looking for a price of about USD 12.7 per Mbtu. After including transportation and transit charges this would result into a delivered price at the Indian border of about USD 18 per Mbtu. This is a substantially higher price than requested by Iran.

Indian Gas Market

India is unlikely to accept the price demanded by Turkmenistan. Indian officials immediately made a counteroffer at half the demanded price, bringing it more in line with the price for Iranian gas. The price demanded by Turkmenistan is more than four times the price for Indian domestic gas accorded by the Government to private sector Reliance Industry. Reliance's KG field in eastern India is expected to begin production by late 2008. In addition, long-term LNG is supplied from Qatar to Indian's Dahej terminal at USD 2.53 per Mbtu FOB, resulting in a selling price of around USD 4.6 per Mbtu to customers. However, spot LNG cargos have recently been bought by India at prices way beyond the USD 12.7 per Mbtu asked by Turkmenistan. Reports in September 2008 put the price for spot cargos at between USD 21-27 per Mbtu, although these have since declined.

The issues surrounding gas pricing, be it LNG or piped gas, reflect the broader dilemma the Indian gas sector is facing. International gas prices have increased substantially since India auctioned acreage to private developers in 1999 and started to import LNG in 2004. Domestic gas prices have however not increased with international prices and most consumers receive gas at highly subsidized prices.

India's gas consumption during fiscal year 2006/07 was 39.7 bcm[42] whereas net domestic production was only 30.8 bcm. The difference was met through LNG imports. However, total current latent gas demand in India was estimated by the Indian Planning Commission to be around 67 bcm per year for fiscal year 2007/08. Since gas imports started in 2004 the demand-supply gap was partially closed but there is still a large unmet demand. The power and fertilizer sector

[42] India's fiscal year runs from 1 April to 31 March.

dominate gas consumption, accounting for over 80% of total consumption. These two consumers are not yet ready to accept international gas prices as they are selling into markets where they have little flexibility to raise their selling rates in turn.

However, the issue of gas pricing will continue to dominate policy discussions as domestic production from public fields is projected to continuously decline. At the same time production from private sector acreage is expected to grow sharply over the next four years.

Private sector Reliance Industries is set to produce 40 mmcm/d (14.6 bcm/y) by the third quarter of 2008 and to double this amount by 2010. Other new gas is also expected to come on-stream from fields explored by Gujarat Sate Petroleum Corporation and ONGC though commencement of production dates keep getting revised. GSPC's KG field is now expected to commence production by late 2010/2011. Hence, by 2009 total domestic production is expected to reach more than 120 mmcm/d (43.6 bcm/y) after the new gas field becomes operational.

In September 2007 the government finally came forward with a pricing formula for new private domestic production. The price for the Reliance gas was set at a minimum of USD 4.2 per MBtu – below the maximum price of gas from joint venture western off-shore fields that is over USD 5 per MBtu. The pricing formula for the Reliance supply from the KG basin is widely seen as setting a benchmark for future gas pricing in India.

However, given the longer-term likelihood of higher international gas prices and higher price expectations from Turkmenistan, it is debatable whether the Indian policy makers will be able to continue shielding public sector consumers from the harsh realities of global competition for energy.

Open Questions for Caspian Natural Gas Supply to Europe

This paper examines some of the issues that could affect the development of natural gas supply from the Caspian to European markets. It provides background for considering the following questions:

- Shah Deniz Phase II development in Azerbaijan is the main source of incremental gas in the period to 2015. A number of pipeline projects (Nabucco, the Greece-Italy Interconnector, and the Trans-Adriatic Pipeline) and countries in the region – including Russia – are looking to secure this gas. What is the 'European interest' in this phase of Azerbaijan gas export?
- Turkey will continue to play a critical role in determining the future of the 'southern corridor'. Is there any contradiction between efforts to ensure Turkish security of supply, faced with rising domestic demand for gas, and its role as a transit country for Caspian gas?
- What are the difficulties facing energy infrastructure projects linking the Caspian region to European markets; how have these been affected by events in Georgia?
- What are the longer-term challenges for Europe to develop direct gas relationships with Caspian producers, including those in the East Caspian?

Introduction

The Caspian region is already a source of gas supply to European markets, since 2007 as a function of small but growing volumes from Azerbaijan, but also indirectly through the substantial contribution of East Caspian producers to the Russian gas balance, and 'virtual transit' through Iran whereby small volumes exported from Turkmenistan to Iran free up roughly equivalent volumes of Iranian gas for export to Turkey.

The strategic question is how exports from Azerbaijan will develop, and whether any of this existing gas supply and (more likely) additional supply from the region will reach Europe along the new transportation corridor through the South Caucasus. Operated on a transparent, commercial basis, this gas corridor has the potential to make a significant contribution to Eurasian market diversity and security.

The intention of this paper is to raise some of the issues that are affecting the development of this southern corridor, and to what extent this picture has changed as a result of the Russia-Georgia conflict. It focuses on issues that are within the scope of government action (although this too is a moving target since it is interpreted more broadly the further you go upstream; this is one of the challenges for coordination of a long multi-jurisdiction supply chain).

For gas supply projects, governments need to reduce non-commercial barriers as much as possible so that, when market players are ready, they are not prevented or deterred from acting. This is particularly true for long and complex supply routes across multiple national borders such as the route for Caspian gas to Europe.

The paper is divided in two parts between short-term issues to 2015, primarily to do with opening up the corridor for export from Azerbaijan, and some longer-term issues that relate primarily to the relationship with potential suppliers in the East Caspian.

Developing the Europe-Caspian gas trade (to 2015):

➢ ***Competition for Shah Deniz Phase II***

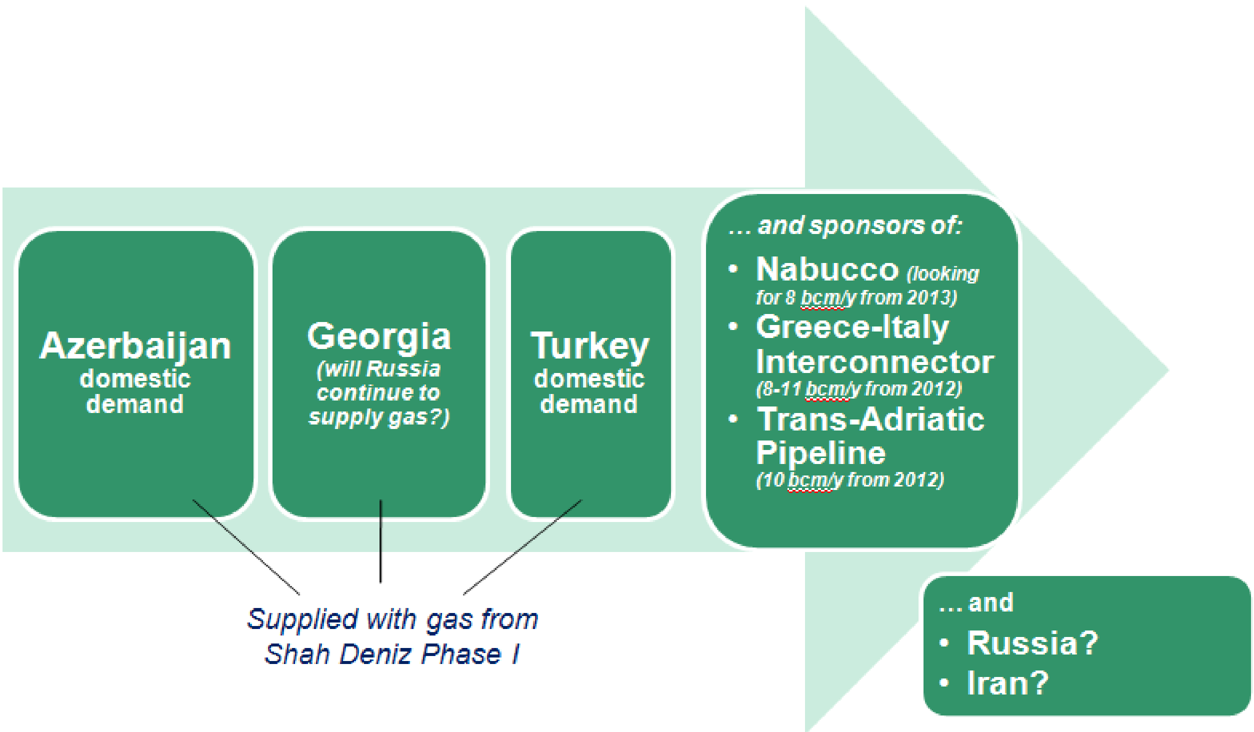
Most of Azerbaijan's exports originate from the offshore Caspian Shah Deniz field. Phase I gas from this field, which is expected to reach its plateau of 8.6 bcm/y in 2009, is fully contracted to Georgia and Turkey, with small volumes re-exported from Turkey to Greece.

In the period to 2015, the main incremental supply that will become available for the Europe-Caspian gas trade is Shah Deniz Phase II. Assumptions about expected volumes vary, but this could eventually amount to an additional 12-15 bcm/y, starting from 2013, of which 9-12 bcm/y could be available for export. Competition for this resource is coming from three pipeline projects, as well as from Turkey and potentially also from Georgia. The pipeline projects are: (see annex for more details):

- Nabucco (25-31 bcm/y from 2017-18, but initial volumes of 8 bcm/y from 2013)
- Greece-Italy Interconnector (plans to export 8-11 bcm/y from 2012)
- Trans-Adriatic Pipeline (10 bcm/y capacity, 5.5 bcm/y contracted from Iran, subject to the availability of Iranian gas for export and upon securing the necessary gas transportation rights through Turkey)

Even before considering demand from the Turkish market, an additional 9-12 bcm/y from Azerbaijan would not appear sufficient to support the development of both the Greece-Italy Interconnector and the Nabucco project according to their announced schedules.

Figure 5: Interest in gas supply from Shah Deniz Phase II



In June 2008 Russia offered to buy Shah Deniz Phase II gas at 'European-level' prices, and Iran has also expressed an interest. Russia was a supplier of gas to Azerbaijan until 2007, and the Soviet-era pipeline along the Caspian coast between Russia and Azerbaijan has a design capacity of 13 bcm/y (although real operating capacity is most likely considerably lower and the pipeline would need technical work if flows were to be reversed). From a Russian perspective, getting Azerbaijan to supply the northern Caucasus areas of Russia makes strategic sense; it would supplement the Russian gas balance for the South Stream project, and soak up available Azerbaijan gas that might otherwise support alternative routes through Turkey further into Europe.

For Azerbaijan too, there is a certain logic in *considering* the Russian and Iranian proposals and keeping them on the table, since they provide Azerbaijan with additional leverage in its negotiations with European transit countries and purchasers. There may be fewer good reasons for Azerbaijan to accept, since this would be at odds with the westward-looking strategic direction of Azerbaijan's foreign policy and the vision of Azerbaijan as a major autonomous supplier to international markets.

This level of interest in Shah Deniz gas is advantageous for Azerbaijan as the resource-owner and for the members of the Shah Deniz consortium. There is a strong argument to say that normal commercial competition should decide which of these proposals prevails. On the other hand, this situation creates some disadvantages for a common European approach to Azerbaijan, faced now with competition from Russia and Iran. Different European countries favour different pipeline projects that meet their national energy interests, and make clear these preferences to the Azerbaijan authorities – often with reference to various signs of European endorsement for their projects. This resulting picture is somewhat confused, leading to the understandable question from the Azerbaijan side: 'What does Europe really want?'

A large volume pipeline such as the Nabucco project tends to generate and stimulate investment upstream, and – once built – can 'suck' additional gas towards its target markets. This would meet an important strategic interest of the EU and could also provide sufficient volumes and liquidity to underpin genuine market-based gas trading in Turkey. However, Nabucco has no gas supplier on board for the moment and no guarantees that initial volumes will be available. In a commercially driven environment where available gas is relatively scarce, the initial volumes for a project like Nabucco can be pulled towards smaller capacity projects that are better attuned to short-term market conditions – but which may, on the other hand, limit the volumes of gas attracted to Turkey and other European markets in the medium-term.

- ***How much gas will get beyond Turkey?***

Turkey will continue to play a critical role in determining the future of the 'southern corridor' as a function of its demand for gas, its diplomatic weight in the region, and its role – yet to be fully defined – as the gatekeeper for export to other European markets.

Increasing demand for gas in Turkey could limit in practice the amount of Caspian gas available for export to the rest of Europe. For several years Turkey has experienced a supply overhang but gas demand is set to rise quickly, driven by gasification and economic growth. Turkey consumed 16 bcm of natural gas in 2001, but more than 19 bcm already in the first six months of 2008. According to BOTAS, demand could reach 56 bcm/y by 2015 and 76 bcm/y by 2030. Unless new contracts are signed, Turkey's contractual surplus is set to become a deficit in the period after 2012.[43] Moreover, without new investment in the pipeline network, rising domestic demand would also reduce the amount of spare capacity within the Turkish transmission system.

[43] Under the 2001 Turkish Natural Gas Market Law, BOTAS is required to reduce its share of imports to 20% of national by 2009 through contract releases; it is prohibited from renewing expired contracts or entering

Concerns about security of gas supply and the future of the domestic liberalisation agenda have coincided with discussions about the gas transit regime across Turkey. Upstream partners of Turkey as well as the EU and BOTAS' partners in the Nabucco consortium are looking for assurances of non-discriminatory access to the Turkish pipeline network and cost-based tariffs for transit. Alongside the principle of cost-based transportation tariffs, reports suggest that the Turkish preference is for BOTAS to have an entitlement to a percentage of transit gas, purchased at a netback price from the intended destination market. While this appears to have been accepted in principle by some downstream partners, it presents difficulties to suppliers wishing to market gas directly to consumers beyond Turkey, and for the development of the Nabucco project. The challenge remains to address Turkish concerns about gas supply without creating obstacles to transit that could impede the development of the gas corridor.

- ***New conditions for infrastructure development***

Getting the conditions right for construction of long-distance cross-border pipelines is a new challenge for Europe. In the past, suppliers tended to take care of pipeline construction to Europe markets, and – in the case of Soviet gas deliveries – political control over the route meant that transit was not an obstacle to the development of new routes. Within Europe, large national or regional incumbents developed the gas business and pipeline infrastructure as a monopoly within a defined area.

The situation for construction of new pipelines – particularly for pipelines carrying Caspian gas to European markets – is quite different. In this case, suppliers are not taking the lead in developing new infrastructure and the task is left to European companies to coordinate and build new infrastructure that can meet future European demand and ensure security of supply. This has to be done in a new competitive regulatory environment.

The task of putting together a long cross-border pipeline within Europe is complicated by the fact that Transmission System Operators (TSOs) generally have responsibility for networks in a defined sub-region or country, rather than optimising pipeline networks on a larger regional or Europe-wide basis. Where new pipelines extend beyond the EU and the reach of its internal market rules, there is the additional challenge to ensure that compatible rules for gas transmission / transit are in place along the entire pipeline route.

Incumbents with strong positions in large European markets have better capacity to raise capital for infrastructure developments, based on a stronger credit rating. This makes them attractive partners for new infrastructure projects (as witnessed by Gazprom's choice of project partner for its own pipeline projects). For pipelines linking Europe to markets in the Caspian, this is creating the somewhat paradoxical situation that pro-competitive pipelines need to look for traditional European market players as partners in order to improve their credit profile.

Increased perceptions of (geo-) political risk in the South Caucasus following the conflict in Georgia only increase the difficulty and cost of infrastructure projects in this region. In order to get projects off the ground and mobilise equity investment and commercial financing, investors may look for greater support from multilateral funding agencies and export credit agencies, as well as stronger backing from governments.

into new ones until its share of imports reaches this figure. BOTAS is arguing for amendments to the 2001 law.

Longer-term challenges

European demand for natural gas is set to grow over the coming decades, driven to a large degree by an expansion of gas-fired electricity generation. Demand for imported gas will increase more quickly than overall demand, because indigenous European production has reached a plateau. Projections of gas demand and supply are subject to a high degree of uncertainty, chiefly concerning the level of economic growth, improvements in energy efficiency, relative fuel prices, and EU policy on climate change and renewables.

The competitive position of gas from the Caspian and the Middle East will be affected by the energy policy and commercial gas export strategy pursued by Russia. The Gazprom / ENI South Stream project would connect Russia's Black Sea coast with Bulgaria, and then split into two pipelines supplying south and central Europe. This project has the potential to supply markets targeted by the Nabucco, Trans-Adriatic and Greece-Italy interconnector projects, but there are still questions about upstream investment in Russia and gas availability for South Stream, as well as the whether the estimated EUR 10-12 billion investment cost for this project makes this an optimal way to bring Russian gas to market.

The main challenge for Caspian gas trade with Europe is the availability of gas[44]. Azerbaijan has considerable upside potential for gas production and export beyond Shah Deniz Phase II, with the consortium developing this field announcing in 2007 the discovery of a deep reservoir beneath the currently producing structure. Alongside Shah Deniz, there is the possibility of additional production from SOCAR fields as well as other deep offshore fields such as the Absheron field. However, the offers from Russia and Iran in 2008 to buy Azerbaijan gas were a reminder that an assumption of European access to gas in the western Caspian cannot be taken for granted.

The larger reserves and production potential is on the eastern side of the Caspian, and in Turkmenistan in particular. Turkmenistan has ambitious plans to expand production and export but has an established export channel to Russia, a 1997 pipeline to Iran, and a new large-volume link between Turkmenistan and China, running through Uzbekistan and Kazakhstan, which is scheduled for first operation in 2009 / 2010. Transparency on reserves and increased upstream investment will determine the extent to which Turkmenistan can support multiple export routes.

In the past, the comparative advantage of the southern corridor for East Caspian producers has been based mainly on price. Russian control over the only large-volume export route meant that it could keep export prices below market levels and capture a share of resource rent from Turkmenistan and other East Caspian exporters. Under these circumstances, the possibility of reliable access to a deep, reliable and high-value European market provided a significant incentive for East Caspian interest in a southern corridor. This was the background to the first attempt at large-volume trans-Caspian gas trade in the late 1990s; among the reasons that this foundered was a difficulty to align political and commercial relationships across the Caspian.

Since 2007, there has been a marked improvement in the key political relationship for trans-Caspian gas, between Turkmenistan and Azerbaijan. At the same time, however, the prices offered by Russia for East Caspian gas export have risen sharply. In March 2008, Gazprom and the heads of the national oil and gas companies from Turkmenistan, Kazakhstan and Uzbekistan announced that trade in Central Asian gas would, from 2009, take place at 'European-level prices'; this would imply a parity with the price paid on the European market for Russian natural gas, minus the costs of transportation and storage - and a Gazprom margin.

[44] According to the Nabucco Pipeline Company, the potential supply sources for the pipeline are "Azerbaijan, Egypt, Russia, Iran and even from Iraq at a later point in time. Furthermore it remains to be seen if also gas from Turkmenistan and Kazakhstan will be linked with the Nabucco pipeline system."

Russia’s readiness to transmit higher international prices to Caspian producers underlines Russia’s need for Central Asian gas to make up its own gas balance. It also reflects Moscow’s determination to maintain its strong relationships with gas producers in the region in the face of increased competition from China / Europe and signs that Turkmenistan might be ready to engage in a more predictable way with the wider world. The Russian offer of ‘European-level netbacks’ for Caspian gas export might not be sustained if the option of a southern corridor starts to fade, but for the moment it has eroded one of the route’s major attractions for Caspian gas producers.

Turkmenistan has not ruled out the idea of trans-Caspian gas trade, and – despite uncertainty over gas availability and transportation routes – the European Commission announced following talks in Ashgabat in April 2008 that Turkmenistan was ready to commit 10 bcm/y to trade with Europe. Turkmenistan has also invited international companies to invest in offshore exploration on Turkmenistan’s Caspian shelf. The presence of an international investor with gas or associated gas in the Turkmen mid-Caspian would provide a plausible medium-term opportunity to supplement volumes available for the southern corridor. There are thousands of kilometres of pipeline already along the Caspian seabed, and it would be a relatively simple technical proposition to connect the offshore facilities of Azerbaijan and Turkmenistan.

Any decision by Turkmenistan to sanction a Caspian interconnector would be the subject of careful political calculation. The existing international agreements on the Caspian neither permit, nor prohibit, trans-Caspian pipelines, but Russia (and Iran) has argued that trans-Caspian undersea pipelines require the consent of all Caspian littoral states. Post-Georgia, the perceived costs of disagreement with Russia have become higher, and, from the perspective of an East Caspian gas producer, it would require a compelling commercial and political case to make the risk worthwhile.

At present, the ‘Baku initiative’ provides the framework for energy cooperation between the EU and the Caspian producers, supplemented by bilateral memoranda of understanding with Azerbaijan, Kazakhstan and Turkmenistan. The underlying idea is that common energy interests can be advanced through a gradual process of regulatory approximation towards European norms. In practice, this has not captured the imagination of Caspian producers, who feel that the strategic and commercial value of the gas trade – rather than the details of the Gas Directive – should be the basis of their energy relationship with the EU.

In developing a long-term basis for gas cooperation that could encourage the dedication of Caspian resources to the southern corridor, the EU and Turkey could consider mechanisms to provide for a long-term political and commercial commitment to large volume gas purchases, possibly in the form of aggregated demand from different market players along the chain, supported by an overall off-take guarantee, alongside a clear definition of principles regarding pricing, transit arrangements and infrastructure development.

- The export corridor from Azerbaijan through Georgia has become a major route for Caspian oil to international markets and, since 2007 also for Azerbaijan gas export to Turkey.
- The main disruption to supply along this corridor occurred before the outbreak of hostilities between Russia and Georgia. An explosion and fire on the Turkish section of the Baku-Tbilisi-Ceyhan (BTC) oil pipeline on 5 August meant that deliveries through the BTC were interrupted until 26 August.
- The Georgia-Russia conflict itself, which began on the night of 7/8 August, had only a minor short-term impact on energy flows through the South Caucasus. The main effect was to limit the options for re-directing BTC oil along other routes.
- Nevertheless, by increasing perceptions of risk in the South Caucasus and the perceived cost of disagreement with Russia, the conflict could affect the direction of future Caspian oil and gas exports, which could in turn have an impact upon market diversity and security.
- Much will depend on developments in Georgia. Russia has the means, if it chooses to do so, to exert pressure on Georgian politics through its strong influence over the Georgian gas and electricity sector.
- Companies have invested heavily in oil transportation infrastructure and terminals in the South Caucasus and there is no sign of any short-term shift in oil export strategy in the region. While the conflict increases the possibility that greater volumes of Kazakhstan oil production will be exported to Russia, China and Iran, commercial advantages and the benefits of export diversification mean that routes through Baku and the South Caucasus are likely to remain attractive for Kazakhstan.
- By contrast, the development of the gas corridor through the South Caucasus is at a relatively early stage. While the conflict has underlined the potential strategic value of a southern gas corridor to European security of supply, it has also accentuated some of the difficulties facing this route, particularly in terms of securing gas from the East Caspian.
- Increased political risk makes it more difficult and expensive to finance new infrastructure projects in the region.

Background

Over the last ten years the corridor from Azerbaijan through Georgia has become a major artery for oil transportation to international markets and, more recently, for gas export as well. Georgia hosts pipelines capable of carrying some 1.15 mb/d of crude and up to 8 bcm/y of gas; an additional 200 kb/d can be moved through the Georgian rail network. In each case, there are proposals to expand capacity, in the case of oil pipelines up to around 2 mb/d and for gas to 16-20 bcm/y.

The main pipelines running through the South Caucasus are shown in Table 8. The pipeline from Baku to Novorossiysk does not involve transit through Georgia, since it crosses directly from Azerbaijan into Russia.

Table 8: Main oil and gas export pipelines in the South Caucasus

Route	***Start of Operation***	***Oil / Gas***	***Capacity***	***Notes / Expansion plans***
Baku-Tbilisi-Ceyhan	2006	Oil	1 mb/d	*Expansion to 1.2 mb/d by end 2008, possible up to 1.8 mb/d*
Baku-Supsa *Western Route Export Pipeline*	1999	Oil	100 kb/d	*Re-opened summer 2008 following 18 months repair*
Baku-Novorossiysk *Northern Route Export Pipeline*	1983	Oil	100 kb/d	*Originally north-south line, since 1997 sporadic use south-north*
Baku-Tbilisi-Erzurum *South Caucasus Pipeline*	2007	Gas	8 bcm/y	*Expansion to 16-20 bcm/y in line with increased Azeri gas output*

The short-term impact of the conflict

The main interruption to energy flows pre-dated the Russia-Georgia conflict and was caused by an explosion and fire on 5 August at a block valve on the Turkish section of the Baku-Tbilisi-Ceyhan (BTC) pipeline. Media have reported that the PKK claimed responsibility for the explosion, although sabotage has not been confirmed. This disrupted oil shipments that had been running through pipeline at rate of around 870 kb/d. Following repairs, loading began again at Ceyhan on 26 August.

The main short-term effect of the conflict was to limit the options for re-directing BTC oil along other routes. Under normal circumstances, the main alternative routes would have been the Baku-Supsa pipeline (or Western Route Export Pipeline) to the Supsa terminal on the Black Sea and rail shipments across Georgia to Batumi and the newly-opened terminal at Kulevi.

The Baku-Supsa pipeline had been closed since January 2007 for repairs, but was available for use again from summer 2008. Between 45-90 kb/d had been transported to Supsa in early August, but the pipeline was closed on 12 August as a precautionary measure because of the conflict.

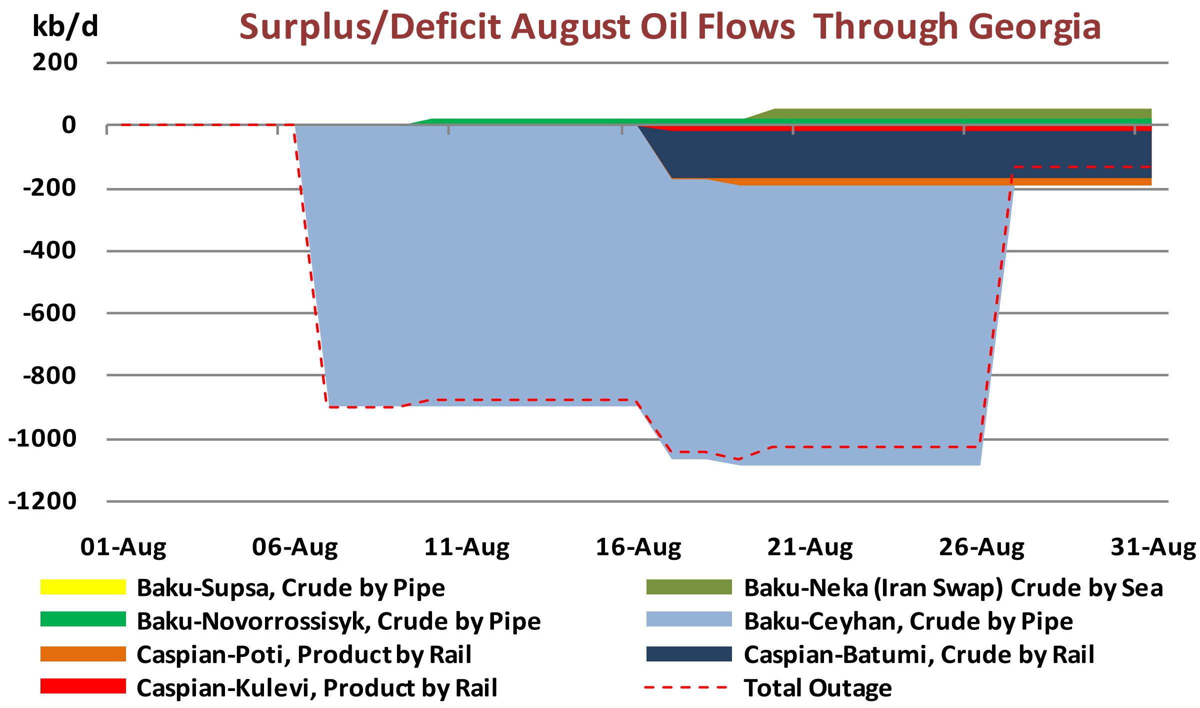
Rail lines across Georgia were damaged by the conflict, notably following the destruction of a key rail bridge on 16 August and a fire caused by a fuel train reportedly hitting a mine on 24 August. This disrupted deliveries to Batumi and Kulevi since the possibilities to re-route rail traffic were limited. According to Georgian railways, reconstruction of the rail bridge was completed on 11 September, and should allow rail shipments to reach pre-conflict levels.

The net effect of the BTC explosion and the Russia-Georgia conflict was that, for a period from mid to late August, the only operational route across the South Caucasus was the Baku-Novorossiysk pipeline (or Northern Route Export Pipeline), which does not cross through Georgia but goes directly from Azerbaijan through the Russian North Caucasus to the Black Sea port of Novorossiysk. During this period the State Oil Company of Azerbaijan Republic (SOCAR) put in place a short-term swap arrangement with Iran for up to three hundred thousand tons of crude delivered to the Iranian Caspian port of Neka.

Gas transit across Azerbaijan was largely unaffected by the conflict, with a precautionary stop to gas inputs to the South Caucasus Pipeline lasting only two days, from 12-14 August.

The Russia-Georgia conflict barely caused a ripple in the markets and the capacity to absorb a supply interruption was indicative of a change in market sentiment from earlier in 2008. Nonetheless, it was important that the impact of the BTC explosion had been digested before the conflict began, otherwise the reaction could have been sharper.

Figure 6: Disruption to oil supply through the South Caucasus, August 2008



Source: IEA

Energy security implications

The conflict in Georgia was not fought over energy and did not result in any lasting disruption to energy transit flows. Although there were reports of Russian bombs landing close to pipeline routes, there are few indications that energy infrastructure was systematically targeted. The short-term energy impact was mostly due to the coincidence of the conflict with the earlier shutdown of the BTC.

Nonetheless, by increasing perceptions of risk in the South Caucasus and the perceived cost of disagreement with Russia, the conflict could influence the strategic calculations of Caspian resource-owners and the development of export routes for Caspian oil and gas. This effect would be amplified in case of lasting instability in Georgia or if another frozen conflict in the region, between Azerbaijan and Armenia over Nagorno-Karabakh, were to be rekindled.

Caspian oil and gas producers, in particular Kazakhstan for oil, and Turkmenistan for gas, are set to increase output over the next 10-15 years. In a tight global market with concerns over levels of investment, any new resources brought to any market are welcome from an energy security perspective. However, particularly for Caspian producers – and particularly for natural gas – the choice of route to market still matters. Insofar as the Georgia conflict deters investment and export through the South Caucasus, this could have a wider impact on energy market diversity and reliability of supply.

The European Council, at its 1 September meeting, noted the link between the conflict and energy security issues, concluding that “recent events illustrate the need for Europe to intensify its efforts with regard to the security of energy supplies”. The rest of this paper considers the possible implications of the conflict for Georgia’s status as a transit country, and for oil and gas transportation routes through the region.

Implications for Georgia

Any impact of the conflict on Georgia's ability to provide secure transit will be watched carefully over the coming months by countries and companies along the Caspian energy supply chain. All of the oil and gas transit infrastructure and oil terminals are within territory controlled by the Georgian government[45], and there is no reason to doubt Georgian political commitment to provide reliable oil and gas transportation[46]. At the same time, the fall-out from the conflict will undoubtedly test Georgia's institutions. Moreover, Russia does have the means, if it chooses, to exert pressure on Georgian politics. A potential channel for this pressure is Russian influence over the Georgian gas and electricity sector.

Electricity generation in Georgia is dominated by hydropower, with three gas-fired power plants and imports meeting peak demand. The key generation asset is the Enguri HPP, which provided an average of 31% of all electricity consumed in Georgia from 2000-2006. This plant straddles the border with Abkhazia and has been operated jointly in order to meet electricity demand on both sides. Georgian officials have said that the plant continues to operate normally and that, for technical reasons, it is difficult to restrict supply to the rest of Georgia without cutting off supply to Abkhazia as well. Nonetheless, the fact that the plant is only partially under Georgian control creates a potential risk to the reliability of electricity supply.

The Russian company RAO UES is a major player in the Georgian energy market. Its main assets are the electricity distribution company in Tbilisi, the most important gas-fired power plant (Mtkvari) and 50% of the 500 kV transmission line which transports electricity from the generation centres in the northwest Georgia (notably Enguri HPP) to the main demand centres in the centre and west of the country.

Russia also supplies natural gas to Georgia, with deliveries of 1.2 bcm in 2007, around 75% of total Georgian gas consumption. This is contracted to private customers such as the Kazakh company KazTransGaz (part of KazMunaiGaz) which took over gas supply to Tbilisi in May 2006. It is not clear whether, and under what conditions, gas will be supplied in 2008-2009. Georgia also provides transit for Russian gas supplied to Armenia (1.9 bcm in 2007).

Implications for oil transportation

Companies have invested heavily in oil transportation routes and terminals in the South Caucasus and there is no sign of any short-term shift in oil export strategy. The state-owned energy companies in Azerbaijan and Kazakhstan are among the biggest foreign investors in Georgia: SOCAR brought the Kulevi oil terminal on the Black Sea coast into operation in May 2008; KazMunaiGaz is the owner of the Batumi oil terminal.

The re-direction of a portion of SOCAR oil export to the Iranian port of Neka during August and September 2008 suggested that Iran could gain at the expense of routes through the South Caucasus. Neka already handles a portion of exports from Kazakhstan and Turkmenistan in swap

[45] The Kulevi terminal is north of the Black Sea port of Poti and around 15km from the border with Abkhazia; Batumi is to the south of Poti towards the border with Turkey. The Baku-Supsa pipeline and main rail lines pass via Gori and around 10-15km from South Ossetia; the BTC and SCP pipelines are within 25km of South Ossetia.

[46] Georgia, along with all the countries along the gas supply chain from the Caspian to Europe, is a party to the Energy Charter Treaty, which obliges participating countries to take the necessary measures to facilitate transit of energy, consistent with the principle of freedom of transit, and to secure established energy flows.

arrangements (around 112 kb/d in 2007). SOCAR has stated that the temporary use of Neka was a purely pragmatic move to cope with disruption in Georgia.

The main question is whether the conflict will affect the direction of future Caspian oil exports. Decisions need to be made in the next two to three years about expanding export capacity to accommodate rising oil production in Kazakhstan. One of the main options for bringing this output to market is to increase trans-Caspian oil shipments, notably via the Kazakhstan Caspian Transportation System, which was envisaged to bring an additional 500 kb/d – and eventually up to 1 mb/d – across the Caspian by barge to Baku in the period after 2011. This would require expansion of capacity in the BTC pipeline and possibly the development of other transportation routes across the South Caucasus.

The Georgia conflict has made the implementation and financing of this transportation system even more complex and, especially in case of any lasting instability in Georgia, has increased the chances that oil will be exported from Kazakhstan to Russia, China and Iran. Nonetheless, the route to Baku remains a viable medium-term outlet for Kazakhstan oil. Astana has repeatedly expressed its interest in diversification of oil export routes and the alternatives all have drawbacks of their own. More than 60% of Kazakhstan oil export already goes through Russia. Although expanding the capacity of the Caspian Pipeline Consortium (CPC) pipeline through Russia to Novorossiysk has been a favoured option, it has not been possible to agree CPC expansion despite more than five years of discussion. Aside from the CPC option, operators in Kazakhstan will be wary of increased dependence on the Russian transportation network, especially if there continues to be no oil quality bank for the Transneft system. The pipeline east to China provides welcome diversity but netbacks from sales to China are less commercially attractive than sales in the Mediterranean. Although Iran's relative position was improved by the Georgia conflict, the geographical advantage that it offers is still tempered by political disadvantage.

As production increases, Caspian oil producers will be looking for a balance between commercial considerations and risk, and to avoid wherever possible being locked into a single direction for export. While watchful of developments in Georgia, this should continue to underpin Kazakhstan interest in trans-Caspian oil shipments and an expansion of the South Caucasus oil corridor.

Implications for gas transportation

The Russia-Georgia crisis barely affected the operation of the existing natural gas export pipeline from Azerbaijan to Turkey, the Baku-Tbilisi-Erzurum or South Caucasus pipeline. However, the conflict came at a relatively early stage in regional gas pipeline development and export, and before some of the key links in a 'southern corridor' for gas supply had been put in place. The main effect of the crisis was therefore to accentuate some of the existing dilemmas facing the development of this corridor.

Chief among these are questions about available gas supply and about the transit and marketing arrangements for the corridor. Azerbaijan became a net exporter in 2007 and is set to increase gas production substantially in the coming years, principally as a result of Phase II development of the Shah Deniz field. With the expansion of the South Caucasus Pipeline, commercial logic suggests that this gas should be pulled westwards through Georgia to Turkey and beyond. However, the Georgia crisis has added to uncertainty over the timing and markets for Azerbaijan gas, with the conditions for bringing the gas to European buyers still not clear – and a Russian offer to buy Azeri gas at 'European' prices also on the table.

Azerbaijan in any event could cover only a part of demand for 'southern corridor' gas, given rising gas use in Turkey and the demands of three planned European pipeline projects: the 30 bcm/y

Nabucco project (even if only for initial volumes); the 8-11 bcm/y Greece-Italy Interconnector and the 10 bcm/y Trans-Adriatic pipeline.

A potentially larger prize is on the eastern side of the Caspian, where Turkmenistan has ambitious plans to expand gas production and export. The likelihood of a new export route to China after 2009 – and the possibility of trade with Europe – has strengthened the East Caspian countries' negotiating hand with Russia, their main customer, and enabled them to improve the price which they obtain for their product, which was previously well below the netback to European markets. The Russian offer of 'European-level netbacks' for Caspian gas export might not be sustained if the option of a southern corridor becomes less credible, but for the moment it has eroded a key comparative advantage of the trans-Caspian route for Caspian gas producers. With China set to provide a degree of market diversification, and with uncertainty over Turkmenistan's reserves and production potential and long-term high-volume supply commitments in place to Russia and to China (after 2009), there already were doubts before the Georgia conflict about the incentives for Turkmenistan to support an additional export route across the Caspian.

Turkmenistan has not ruled out the idea of trans-Caspian gas trade and has also invited international companies to invest in offshore exploration on Turkmenistan's Caspian shelf. However, a decision by Turkmenistan to sanction a Caspian interconnector would be the subject of careful political calculation. The existing international agreements on the Caspian neither permit, nor prohibit, trans-Caspian pipelines, but Russia has argued that trans-Caspian undersea pipelines require the consent of all Caspian littoral states. Post-Georgia, the perceived risk of disagreement with Russia has become higher, and, from the perspective of an East Caspian gas producer, it would require a compelling commercial and political case to make the risk worthwhile. Downstream governments that stand to benefit from market diversity need to examine what they are prepared to offer to make this case, including possibilities to mitigate and/or underwrite the investment, transit and supply risks along the southern corridor.

Annex: Caspian Oil and Gas Transportation Projects

Oil Transportation

The main export options that could accommodate increased oil export from Kazakhstan are described in the following pages. Since some of these projects would increase volumes arriving at Black Sea ports, the main Bosporus by-pass options are included as well. The cumulative capacity of all the proposed pipelines is greater than the likely increase in Caspian oil output. Given that many of the proposed projects are competing for the same sources of oil, it is clear that not all projects currently under discussion will go ahead. The main pipelines (but not all of the Bosporus bypass options) are also shown on the accompanying map (Figure 7).

Pipelines through Russia:

- Caspian Pipeline Consortium (CPC) Pipeline

To China:

- Kazakhstan-China Oil Pipeline

Trans-Caspian

- Kazakhstan Caspian Transportation System (KCTS)

South Caucasus

- BTC expansion

Other Bosporus bypass options

- Bourgas-Alexandroupolis Pipeline
- Trans-Anatolian Pipeline (Samsun-Ceyhan)
- Pan-European Oil Pipeline (PEOP)
- AMBO Pipeline (Bulgaria-FYR Macedonia-Albania)
- Odessa-Brody(-Plock) Pipeline

Expansion of the Caspian Pipeline Consortium (CPC) Pipeline	
Route:	Kazakhstan (Tengiz) – Russia (Novorossiysk)
Distance:	1 510 km
Capacity:	from current 650 kb/d (32.5 mt/y) to 1.34 mb/d (67 mt/y)
Estimated Cost:	USD 2.5 billion
Earliest Completion Date:	uncertain

The Caspian Pipeline Consortium (CPC) started operation of the pipeline from the Tengiz oilfield in western Kazakhstan to Russia's Black Sea port of Novorossiysk in October 2001, opening up the first direct oil export route to world markets for Kazakh oil. At the time, capacity on the pipeline was 565 kb/d (28 mt/y), but throughput quickly reached this limit. Since 2002, the consortium members have been looking to expand capacity, a debate that has continued without resolution. The expansion proposal would take design peak capacity to 1.34 mb/d (67 mt/y). In the absence of consent to formal expansion, the CPC has nonetheless managed to push pipeline capacity up to around 650 kb/d through the use of drag agents.

In the long debate on CPC expansion, Russia has argued for higher transit tariffs, a restructuring of the consortium's debt, and pushed for Kazakhstan to commit to the Bourgas-Alexandroupolis pipeline from Bulgaria to Greece as the route for Kazakh oil exports out of the Black Sea. Although other CPC shareholders have consented to higher transit tariffs and debt restructuring, a decision on expansion has remained out of reach.

The latest agreement was announced in May 2008 following a meeting between the then Russian Minister of Industry and Energy, Viktor Khristenko, and his Kazakh counterpart, Sauat Mynbayev, which resulted in the signature of a Memorandum of Agreement. This Memorandum has yet to lead to a breakthrough. Reaching a consensus on CPC expansion is one way for Russia to affect the momentum gathering behind alternative routes to market, such as the Kazakhstan Caspian Transportation System that would bring north Caspian oil to Azerbaijan.

The CPC pipeline is the only export pipeline on Russian territory with partial private ownership. Private companies own 50% of the consortium, with the other 50% belonging to states (Russia 24%, Kazakhstan 19%, Oman 7% - there have been reports that Oman is considering selling its share, both Russia and Kazakhstan have expressed interest in buying it). CPC partners have commissioned an updated feasibility study on expansion that is due to be completed in mid-2009.

An expanded CPC could deliver an incremental 750 kb/d (37.5 mt/y) of oil into the Black Sea; aside from Bourgas-Alexandroupolis, there are various other Bosporus bypass projects that could relieve pressure on the Straits (see below: Trans-Anatolian Pipeline, PEOP, AMBO, and Odessa-Brody).

Kazakhstan – China Oil Pipeline	
Route:	Kazakhstan (Atyrau) – China (Alashankou), in three stages
Distance:	2 163 km (total length of new pipeline, of which 1 411 already built)
Capacity:	current 200 kb/d (10 mt/y), eventual up to 400 kb/d (20 mt/y)
Estimated Cost:	for 962 km Atasu-Alashankou (stage 2) USD 800 million
Earliest Completion Date:	2009, but likely to be synchronised with Kashagan production

The idea for a Kazakhstan-China pipeline to serve China's growing energy needs dates back to a 1997 agreement between CNPC and the Ministry of Energy and Natural Resources of Kazakhstan. This agreement defined the overall framework for the project and the route, from the oil hub Atyrau on the north Caspian shore to Alashankou in China's north-western Xinjiang region.

A 1999 inter-governmental agreement between China and Kazakhstan on cooperation in the oil and gas sector specified that CNPC would be responsible for pipeline construction and financing, while Kazakhstan would allocate land for pipeline construction, and provide guarantees both in terms of pipeline safety and security and also regarding the regulatory regime for oil export and equipment import.

Construction of the first westernmost stage of the project was completed in 2004, and since then has been bringing oil from the Aktobe region *west* to Atyrau. This section of the pipeline (449 km, capacity up to 240kb/d [12 mt/y]) will be reversed when all stages are complete.

The second stage was a 962 km pipeline from Atasu in north-eastern Kazakhstan to Alashankou in China. This was commissioned in 2006, and brings oil east to China from CNPC's Aktobe field and from CNPC and KazMunaiGaz's Kumkol fields. PetroChina's ChinaOil is the exclusive buyer of the crude oil on the Chinese side and the commercial operator of the pipeline is a joint venture of CNPC and Kaztransoil. In addition to around 85 kb/d (4.5 mt/y) of Kazakh crude that flowed through the pipeline during 2007, Gazpromneft and TNK-BP are also shipping volumes along this route from Western Siberian fields via the Omsk-Pavlodar pipeline.

The final and 'middle' stage of the project will connect Kenkiyak and Kumkol at a cost of around USD 1 billion. It will provide a link between the first two sections, and will theoretically double the pipeline capacity to 400 kb/d (20 mt/y). Construction has started, and completion of this final leg will in part be dependent on the availability of Kashagan crude oil. The quantity of crude oil supplied to China through this route will still represent only a small percentage (i.e. less than 5%) of China's expected oil demand by the time the project is fully operational.

Kazakhstan Caspian Transportation System (KCTS)

Route:	Kazakhstan-Azerbaijan
Distance:	750 km pipeline + trans-Caspian transport
Capacity:	500 kb/d (25 mt/y), potentially up to 1 mb/d (50 mt/y)
Estimated Cost:	USD 3 billion
Earliest Completion Date:	2012

Around 15% if Kazakhstan oil exports are already shipped across the Caspian Sea from the Kazakhstan port of Aktau to Russia, Iran and Azerbaijan. In 2007, these trans-Caspian oil shipments averaged around 184 kb/d (9.2 mt/y), with around 84 kb/d going to the Russian Caspian port of Makhachkala, 68 kb/d to Neka (Iran) and 32 kb/d to Baku. Plans to develop the Aktau port foresee the expansion of oil handling capacity to 400 kb/d (20 mt/y).

In addition, KazMunaiGaz and the international oil companies involved in both the Tengiz and Kashagan fields are developing a new transportation system for Kazakhstan crude oil known as the Kazakhstan Caspian Transportation System (KCTS). The KCTS includes a proposed pipeline from Eskene (near Atyrau) on the northern Caspian coast to a new 760 kb/d (38 mt/y) port facility of Kuryk (south of Aktau), a dedicated fleet of large tankers to cross the Caspian Sea, an oil unloading terminal near Baku, and an interconnection with the (expanded) BTC pipeline and possibly with other transportation systems.

In June 2006, Kazakhstan and Azerbaijan signed an Intergovernmental Agreement to facilitate and support the transportation of oil across the Caspian and across Azerbaijan. A memorandum of understanding on the principles of cooperation to set up the KCTS was signed between KazMunaiGaz and the companies involved in the Tengiz and Kashagan projects in January 2007.

A difficulty in developing the KCTS has been to align the interests of all the different parties involved, given that it involves not only the governments of Kazakhstan and Azerbaijan, but also the other shareholders in Tengiz and Kashagan (and in practice also the BTC). This has meant lengthy discussions over tariffs and capacity rights that have delayed implementation.

Increasing volumes of barge traffic across the Caspian mean increased risk of accident and environmental damage, and so should be accompanied by implementation of safety and environmental standards, as included in the relevant international conventions of the International Maritime Organisation.

Expansion of the Baku-Tbilisi-Ceyhan Pipeline	
Route:	Azerbaijan-Georgia-Turkey
Distance:	1 768 km, operational since 2006
Capacity:	current 1 mb/d (50 mt/y), expansion to 1.2 mb/d (60 mt/y) and potentially to 1.8 mb/d (90 mt/y)
Estimated Cost:	n/a
Earliest Completion Date:	initial expansion 2008

Work on an initial expansion of BTC capacity to 1.2 mb/d (60 mt/y) through the use of drag agents began earlier in 2008, and was expected to be completed by the end of 2008 in order to accommodate additional exports from Azerbaijan (from ACG and liquids from Shah Deniz). A much larger project could see further expansion up to 1.6 mb/d (80 mt/y) or even 1.8 mb/d (90 mt/y); this is linked to the possibility of large-scale shipments of Kazakhstan crude to Baku after 2012, mainly via the Kazakhstan Caspian Transportation System.

Bourgas-Alexandroupolis Pipeline	
Route:	Bulgaria (Bourgas) – Greece (Alexandroupolis)
Distance:	279 km
Capacity:	initial 300 kb/d (15 mt/y), potentially up to 1 mb/d (50 mt/y)
Estimated Cost:	EUR 1 billion
Earliest Completion Date:	2010

The idea of an oil pipeline from the Bulgarian Black Sea port of Bourgas to Alexandroupolis in Greece dates back to 1994, when inter-governmental discussions began between Bulgaria, Greece and Russia. The pipeline would run entirely within the European Union. Initially, it would transport 300 kb/d (15 mt/y), gradually increasing to full design capacity of 700 kb/d (35 mt/y) and potentially up to 1 mb/d (50 mt/y). The estimated total cost has increased from EUR 550 million to EUR 1 billion. The project is expected to be funded by a mix of equity and commercial loans.

Since 2006, primarily because of strong Russian support, the B-A pipeline has moved ahead more quickly than other potential Bosporus bypass pipelines. In September 2006, Bulgarian, Greek and Russian heads of state announced they had overcome a deadlock on control of the project's ownership. In March 2007, the countries signed a tri-party intergovernmental agreement (IGA), which was subsequently ratified by their respective parliaments.

The IGA foresees the establishment of an international project company (IPC) that will own the pipeline; this was created in January 2008. A Russian enterprise Bourgas-Alexandroupolis Pipeline Consortium (BAPC), which includes Transneft, Rosneft and GazpromNeft, will have a 51% share in the project company. Bulgarian and Greek entities will each hold 24.5%.

Article 5 of the IGA gives Russia's Transneft sole responsibility for key operational functions and decisions such as contracting, lifting programmes, scheduling, dispatch, and nominations. Together with Russia's 51% stake in the IPC, this implies that operational issues will be firmly under Russian control. Construction of the project could begin in June 2009, and last for around one year.

Trans-Anatolian Pipeline (TAP or Samsun - Ceyhan)	
Route:	Turkey (north-south)
Distance:	555 km
Capacity:	1.5 mb/d (75 mt/y), initial 1 mb/d (50 mt/y)
Estimated Cost:	EUR 2 billion
Earliest Completion Date:	2011

Turkey's Çalik Enerji has been the commercial driving force behind the idea for a Bosporus bypass pipeline to Ceyhan, supported by the Turkish government that has long been interested in Turkish options to relieve pressure on the Straits. Studies on the project began in 2003, and Çalik Enerji submitted an application for a licence to build and operate the line in 2004. In October 2005 the first international company joined the project when Italy's Eni signed a memorandum of understanding on the development and implementation of the pipeline.

The proposed pipeline would run from Samsun on the Turkish Black Sea coast to the Meditteranean port of Ceyhan, already a major export terminal for Caspian and Iraqi oil. An advantage of the route is that it runs entirely within Turkey, thereby avoiding the need for any inter-governmental agreements.

The pipeline construction would be undertaken by TAPCO, a company jointly owned by Eni and Çalik Enerji. Indian Oil announced in December 2006 that it would take a 12.5% stake in the project, and other IOCs (Shell, Total) have also reportedly conducted negotiations, but thus far no new partners have formally joined the consortium. The project feasibility study was completed in March 2006 and a groundbreaking ceremony for the project took place in April 2007; full construction of the line itself has yet to start, primarily because of uncertainty over the sources and timing of supply.

As with other Bosporus bypass options (PEOP, AMBO, Odessa-Brody), the Trans-Anatolian pipeline is jostling for position to becoming the *second* most favoured new exit route from the Black Sea – after the Bourgas-Alexandroupolis pipeline backed by Russia. Its prospects are closely linked to the expansion of Kazakhstan output associated with the Kashagan field, now scheduled to start production in 2013, and the export routes chosen for evacuation of this oil. Insofar as Kazakhstan oil reaches Baku through the Kazakhstan Caspian Transportation System, the preferred route for Baku-Ceyhan transportation is more likely to be the BTC rather than via Black Sea ports to Samsun (assuming that BTC capacity can be expanded).

Pan-European Oil Pipeline (PEOP)	
Route:	Romania (Constanta) – Serbia – Croatia – Slovenia – Italy (Trieste)
Distance:	1 300 km (total, some use of existing lines)
Capacity:	800 kb/d (40 mt/y) up to possible 1.8 mb/d (90 mt/y)
Estimated Cost:	EUR 1.8-2.6 billion
Earliest Completion Date:	2013

The Pan-European Oil Pipeline (PEOP) plans to take oil from the Romanian coast of the Black Sea to refineries in Serbia and Croatia, and on to Trieste (Italy) via connections with the existing Trans-Alpine pipeline (TAL) and the Italian pipeline network. The pipeline is slated to connect two Romanian facilities, starting at Constanta and follow the existing corridor to Pitesti. The route would continue via a new corridor through Serbia (Pancevo) and Croatia (Sisak), then on to Italy (Trieste) via Slovenia or the Istria peninsula.

An IFC-funded feasibility study, conducted in 2005, estimated that a 40-inch pipeline along this route could be operational in 2011 at a cost of EUR 1.8 to 2.6 billion. It would eventually be able to transport from 800 kb/d (40 mt/y) to 1.8 mb/d (90 mt/y) of oil, depending on the chosen configuration; the likely throughput would be in the order of 1.2 mb/d (60 mt/y). The study indicated that financing would be 70% debt by export credit agencies and the EBRD. The remaining 30% would come from private commercial banks. The study found that the project was feasible if supported by preferential tax rates.

Romania has done its share of work to complete financial and marketing studies for this line. However, other countries have not yet defined in detail the pipeline route. For example, no final decision has been made on the possible reverse use of the JANAF pipeline, which currently carries oil eastwards from Croatia to Serbia. The governments of the participating countries (Romania, Serbia, Croatia, Slovenia and Italy) generally support the project, albeit with some reservations. They stepped up their efforts by signing a ministerial declaration together with the European Commission (April 2007 in Zagreb, Croatia). Following the Zagreb meeting, the participating countries established an intergovernmental working group with the objective of developing the framework understandings (i.e. intergovernmental and host government agreements).

A project development company was established in April 2008 by JANAF (Croatia), CONPET and OIL TERMINAL (Romania) and TRANSNAFTA (Serbia) – not joined as yet by parties from Slovenia and Italy. The company has the task to bring additional shareholders on board, and to raise interest from investors and potential suppliers.'

Uncertainty over the sources of oil for the pipeline remains, although there have been signs of interest from Kazakhstan. In August 2007, KazMunaiGaz (KMG) agreed to purchase, from Rompetrol Holding SA, a 75% stake in the Rompetrol Group NV (TRG). The purchase includes two refineries in Romania and 630 gas stations in seven countries. KMG is also the owner of the Batumi oil terminal on the Georgian Black Sea coast. Using PEOP for crude oil shipments to the Romanian refineries (and other destinations) could enhance KMG's regional position. However, Kazakhstan has been under pressure from Russia to direct the bulk of its Caspian exports through the Bourgas-Alexandroupolis pipeline (see above). The envisaged purchase of a majority stake by Gazpromneft in Serbia's NIS could also have an impact on the Serbian position regarding PEOP.

AMBO Pipeline

Route:	Bulgaria – FYR Macedonia – Albania
Distance:	912 km
Capacity:	750 kb/d (37.5 mt/y)
Estimated Cost:	EUR 0.95 billion
Earliest Completion Date:	2012

First proposed in 1994, the Trans-Balkan oil pipeline was to run between the port of Bourgas (Bulgaria) on the Black Sea and the port of Vlore (Albania) on the Adriatic Sea, travelling through Skopje (FYR Macedonia). The project's current promoter, the Albanian-Bulgarian-Macedonian Oil Co. (AMBO), received a grant in 1999 from the US Trade and Development Agency to expand the feasibility study. The second study estimated the 912-km pipeline would have a capacity of 750 kb/d (37 mt/y) and would cost about EUR 950 million. The study indicated that construction could begin in 2005 and the pipeline could be completed by 2008. However, no investment decision has yet been taken and the AMBO project has yet to resolve the question of sources of oil supply and to secure industry backing.

In an attempt to raise institutional support for the project, the governments of Albania, Bulgaria and FYR Macedonia signed in 2004 a political declaration and a memorandum of understanding with AMBO's president. On 31 January 2007, the same governments signed a tri-party intergovernmental agreement, which was to be followed by an environmental impact assessment. The earliest possible commissioning date for the pipeline has shifted to 2012.

Odessa – Brody (Plock) Pipeline	
Route:	Ukraine – (Poland)
Distance:	existing 674 km, extension to Plock an additional 500 km
Capacity:	300 kb/d (15 mt/y)
Estimated Cost:	EUR 500 million (existing pipeline)

The Pivdenny terminal in Odessa and a 674 km pipeline from Odessa to Brody in western Ukraine (connecting to the Druzhba export system) was completed by Ukraine in 2001 with the strategic aim of transporting Caspian oil to refineries in Germany and the Czech and Slovak Republics. However, the pipeline was not able to secure commitments from Caspian shippers; after much political and commercial manoeuvring, the Ukrainian government decided in 2004 to accept a proposal from TNK-BP to use the last section of the pipeline in a reverse direction, i.e. to deliver Russian crude southwards. In this way, a project initially viewed as a means of relieving congestion in the Bosporus ended up increasing the volumes seeking transit through the Straits.

There have been periodic attempts since 2004 to re-visit the original vision for Odessa-Brody, including through an extension of the pipeline to the Polish refinery in Plock (the European Commission financed a feasibility study of this extension). The Plock refinery is currently supplied via the Druzhba pipeline from Russia and has production capacity of around 13.8 mt/y, which amounts to around 275 kb/d. Despite declarations of interest and support, also from Azerbaijan, these plans have yet to come to fruition.

Figure 7: Main oil transportation routes in the Caspian and South Caucasus

Figure 8: Main natural gas transportation routes in the Caspian and South Caucasus

Natural Gas Transportation

There are numerous proposals on the table either to strengthen and expand the existing pipeline network (in the case of the Russian system, and also the South Caucasus Pipeline), or to build new pipelines that can accommodate an anticipated increase in Caspian natural gas production and export. The cumulative capacity of all the proposed pipelines is greater than the likely increase in Caspian gas output. Given that many of the proposed projects are competing for the same sources of gas, it is clear that not all projects currently under discussion will go ahead. The pipelines or pipeline expansion projects listed below are described in more detail in the following pages, along with an overview of legal issues related to the Caspian Sea. The main pipeline proposals, plus Gazprom's South Stream project, are also shown on the accompanying map (Figure 8).

Pipelines to Russia:

- Upgrading of the Central Asia-Centre Pipeline
- Caspian Coastal Pipeline

To China:

- Turkmenistan-Uzbekistan-Kazakhstan-China Pipeline

To Pakistan / India

- TAPI (Turkmenistan-Afghanistan-Pakistan-India) Pipeline

'Southern Corridor' Pipelines

- Trans-Caspian options
- Expansion of the South Caucasus Pipeline
- White Stream
- Nabucco
- Greece-Italy Interconnector
- Trans-Adriatic Pipeline

Upgrading of the Central Asia-Centre pipeline system

Route:	Turkmenistan / Uzbekistan – Kazakhstan – Russia
Capacity:	from current 45-55 bcm/y capacity to 90 bcm/y
Estimated Cost:	n/a

The Central Asia – Centre pipeline system consists of four main export pipelines (SATS-1, 2, 4 and 5), running in parallel to join the Russian pipeline network at Alexandrov Gai. This is the most important artery for export of gas from Central Asia, primarily from eastern Turkmenistan and southern Uzbekistan. The first of the lines, SATS-1, was commissioned in 1967, followed by SATS-2 in 1969, SATS-3 (see below, Caspian Coastal Pipeline) and 4 in 1972, and SATS-5 in 1985. All are in need of investment; poor maintenance means that actual current capacity is estimated at between 45-55 bcm/y.

Because of the condition of the main export route, Uzbekistan re-started export in 2001 along two additional lines leading north through Kazakhstan to Russia (the Bukhara-Ural pipelines); these lines had been built to serve the industrial areas of the southern Urals around Chelyabinsk and Yekaterinburg. There is also one additional Soviet-era line from Kazakhstan to the North Caucasus.

Modernisation and upgrading of the main pipeline system to Alexandrov Gai has been a longstanding priority for Gazprom. In addition to the plans for a Caspian Coastal Pipeline described above, the Russian desire to reinforce this corridor as the main export route for East Caspian gas was reflected in a Declaration on the Development of Gas Transportation Capacity in Central Asia, signed by the Heads of State of Russia, Kazakhstan, Turkmenistan and Uzbekistan in May 2007. This foresees the expansion of capacity along the eastern branches of the pipeline system (i.e. SATS-1, 2, 4 and 5) to 90 bcm/y by 2009-2010. In September 2008, Russia and Uzbekistan announced their intention to construct an additional pipeline through Uzbekistan, running parallel to the existing export lines. It remains to be seen whether the necessary investment will be forthcoming.

Caspian Coastal Pipeline	
Route:	Turkmenistan – Kazakhstan – Russia
Distance:	1 700 km (500 km in Turkmenistan, 1 200 km in Kazakhstan)
Capacity:	20 bcm/y
Estimated Cost:	n/a
Earliest Completion Date:	2010-2011

The Presidents of Russia, Kazakhstan and Turkmenistan signed a widely-reported Declaration on the Construction of the Caspian Coastal Pipeline in May 2007, supplemented in December of the same year by a Trilateral Agreement on Cooperation in the Construction of the Caspian Coastal Pipeline. The aim of the pipeline is to bring gas from western Turkmenistan and from Kazakhstan northwards to join the main Central-Asia-Centre lines in Kazakhstan. At present, gas production in these western areas is associated gas from oil production, and – as oil production and associated gas output grows – an intention of this new pipeline is to ensure that available gas is exported through Russia.

Such a pipeline already exists (the third branch of the Central Asia-Centre pipeline system, SATS-3), with small reported flows of 400 mcm in 2006. The intention is to reconstruct this existing line to bring pipeline capacity of 20 bcm/y, with 10bcm supplied each by Turkmenistan and Kazakhstan. Gazprom announced following a meeting in Ashgabat in July 2008 that the capacity of the Caspian Coastal line could be expanded to 30 bcm/y. The pipeline would be built by Turkmengaz, KazMunaiGaz and Gazprom.

Turkmenistan-Uzbekistan-Kazakhstan-China Pipeline	
Route:	Turkmenistan – Uzbekistan – Kazakhstan – China
Distance:	2 000 km to China border
Capacity:	30 bcm/y (possible expansion up to 40bcm/y)
Estimated Cost:	EUR 14 billion
Earliest Completion Date:	2009

Plans to build an eastern export route for Turkmenistan gas advanced rapidly in 2007-2008 following signature of a General Agreement on Gas Cooperation between China and Turkmenistan in April 2006. The foundations for this export route are a PSA for the China National Petroleum Corporation (CNPC) to develop reserves in eastern Turkmenistan, and a 30-year gas sale and purchase agreement for up to 30 bcm/y signed in July 2007 (the CNPC PSA is scheduled to cover around 13 bcm/y of the gas foreseen for export, the rest would have to be provided by Turkmengaz from other production sites). During President Berdymukhammedov's visit to China in

August 2008, he proposed to Chinese President Hu Jintao that peak export volumes from Turkmenistan would reach 40 bcm/y.

A ground-breaking ceremony for the relatively short section of the pipeline (188 km) within Turkmenistan took place in August 2007, and a contract for construction was awarded to the Russian company Stroitransgaz. China signed an agreement in April 2007 with Uzbekistan on pipeline construction, and work was reported to have begun on the 530km line through southern Uzbekistan in June 2008. The main route also crosses southern Kazakhstan (around 1 300 km), and a groundbreaking ceremony took place in July 2008 for this section.

Kazakhstan has a longstanding wish to link its gas-producing areas in the northwest of the country to the main consumption areas in the south, primarily in order to reduce dependence on imports from Uzbekistan. This link would open up the possibility for Kazakhstan to feed gas into the China pipeline.

Within China, the pipeline would connect to the second west-east pipeline, running from northwestern Xinjiang province to Guangzhou. This pipeline also has a planned capacity of 30 bcm/y. Deliveries along the Turkmenistan-China pipeline are officially scheduled to begin already in the last quarter of 2009, with supplies gradually increasing towards full design capacity.

Turkmenistan-Afghanistan-Pakistan-India Pipeline (TAPI)

Route:	Turkmenistan-Afghanistan-Pakistan-India
Distance:	1 680 km
Capacity:	30 bcm/y
Estimated Cost:	EUR 7.6 billion
Earliest Completion Date:	uncertain

The idea of a southern export route for Turkmenistan gas regained momentum again following the overthrow of the Taliban regime in Afghanistan in 2001. The current energy cooperation between Turkmenistan, Afghanistan and Pakistan began in May 2002 with the creation of a Steering Committee for the pipeline, made up of the three energy ministers. The Asian Development Bank (ADB) has acted as a development partner for the project, providing technical and financial assistance.

A technical and economic feasibility study, funded by ADB and completed in 2003, found that the pipeline would be advantageous compared to LNG imports and could be supported by demand from Pakistan alone. Afghanistan would benefit from transit fees, but could also use the pipeline to promote gasification and as an export route for any domestic natural gas production. The study estimated the cost of the pipeline at USD 3.3 billion, but this estimate was raised in 2008 to USD 7.6 billion. ADB also completed a study of gas storage options in Pakistan, which could serve as a means of meeting local demand peaks and of countering transit risks and possible supply disruptions.

After participating as an observer in the discussions, India was formally admitted as a participant in the gas pipeline project at a Steering Committee meeting in April 2008 in Islamabad, and the four countries became parties to a framework agreement on project implementation. A few days later, President Berdymukhammedov’s visit to Kabul, the first by a Turkmen President, was a signal of Turkmenistan’s interest in the project.

The pipeline would run from the Dauletabad gas fields in southeast Turkmenistan and two routes are being considered; a southerly option would go through Herat and Kandahar in Afghanistan, and then across Pakistan to the Indian border town of Fazilka; a more northerly route, being examined at Indian request, would go via Mazar-e-Sharif, Kabul and Peshawar to Lahore and the Indian city of Bikaner. First deliveries are provisionally scheduled for 2015, which would require pipeline construction to begin in around 2010.

Progress with the pipeline is contingent on four major issues; (i) confirmation of additional resource availability in Turkmenistan; (ii) improvements in the security situation in Afghanistan and the consolidation of a level of mutual trust between India and Pakistan; (iii) interest from international oil and gas companies to take a lead role in the pipeline consortium, and (iv) agreement on pricing.

Trans-Caspian options	
Route:	Turkmenistan / Kazakhstan – Azerbaijan

Proposals for trans-Caspian gas trade date back to the mid -1990s. In May 1999, Turkey and Turkmenistan signed a 30-year agreement for deliveries of 30 bcm/y to Turkey, and later the same year an intergovernmental declaration was signed by Azerbaijan, Georgia, Turkey and Turkmenistan supporting a trans-Caspian pipeline that would run through the South Caucasus. The international consortium backing the project consisted of Shell and pipeline development company PSG. However, the project ran into difficulties over payment and price issues and over the allocation of pipeline capacity to Azerbaijan after the Shah Deniz gas field discovery in 1999. Unsettled legal issues related to the Caspian Sea (see below for more information) also provided a basis for Russian and Iranian opposition to the project.

Attention to trans-Caspian and mid-Caspian options intensified again from 2006 in parallel with concern about Europe's energy security and the need for diversity of gas supply, following the Russia-Ukraine gas dispute. The new administration of President Berdymukhammedov in Turkmenistan showed interest in trans-Caspian gas export as part of the strategic goal to develop multiple export routes. Azerbaijan and Turkey have also expressed support. Thus far the renewed examination of trans-Caspian options remains at the stage of feasibility studies, supported by both the EU and the US.

The European Union, through its INOGATE programme, financed a pre-feasibility study of gas transportation routes from Central Asia to European markets; results were presented in November 2007. The study focused on non-pipeline options for trans-Caspian energy transportation, and concluded that a transit corridor for East Caspian gas would be financially viable. CNG (compressed natural gas) was identified as the preferred non-pipeline option for trans-Caspian gas trade. CNG trade would require a compressor station at the loading port, specialised CNG shuttle carriers, and a decompression station at the receiving port (although if similar pressure is available, gas can be discharged directly into the gas transmission network).

A second option would be to land associated gas from offshore Turkmenistan oil production in Azerbaijan. This would involve a relatively short mid-Caspian interconnection to offshore installations in the Azerbaijan sector. A third option would be a fully-fledged trans-Caspian pipeline to Azerbaijan. This could start from Turkmenistan or from Kazakhstan (either direct or via Turkmenistan); the easiest route across the Caspian from a technical / geological perspective is from Turkmenistan). The US Trade and Development Agency is financing a feasibility study for SOCAR on trans-Caspian oil and gas routes; work on the study began in April 2008.

Expansion of the South Caucasus Pipeline	
Route:	Azerbaijan - Georgia - Turkey
Distance:	692 km (to Georgia-Turkey border)
Capacity:	current 7.8 bcm/y, expansion up to 16-20 bcm/y
Earliest Completion Date:	2012

The South Caucasus Pipeline (or Baku-Tbilisi-Erzurum Pipeline) brings gas from the Shah Deniz offshore gas field in the Azerbaijan Caspian Sea to Turkey. The pipeline runs parallel to the Baku-Tbilisi-Ceyhan pipeline oil through Azerbaijan and Georgia. Deliveries of gas began in December 2006, and current pipeline capacity has been designed to accommodate the first phase of Shah Deniz development (up to 8.6 bcm/y production from 2009, of which 6.6 bcm/y for delivery to Turkey).

A decision on expansion of the South Caucasus Pipeline could be taken by the end of 2008 that would increase capacity to 16-20 bcm/y by 2012. This would be linked to second phase development of Shah Deniz. The South Caucasus Pipeline is the main conduit for Caspian gas for delivery to Georgia and Turkey, and through Turkey to markets in Southeast Europe.

White Stream	
Route:	Georgia - Ukraine - Romania (also option for direct Georgia - Romania)
Distance:	1 355 km (1 235 km if direct)
Capacity:	8 bcm initial (stage 1), up to 32 bcm/y
Estimated Cost:	EUR 3.8 billion (stage 1)
Earliest Completion Date:	uncertain

The White Stream project is an initiative to bring Caspian gas across the Black Sea from Georgia to Romania (either directly, or via Ukraine through Crimea). The project, which was formerly known as the Georgia-Ukraine-European Union (GUEU) pipeline, would by-pass both Russia and Turkey. It foresees an initial capacity of 8 bcm per year rising to 32 bcm. It has generated some interest and political support, notably from Ukraine, but lacks clarity on the sources of natural gas and commercial sponsors. More than other projects in the region, the viability of the White Stream project was called into question by the Russia-Georgia conflict.

Caspian Sea Legal Issues

Unresolved questions about the legal status of the Caspian Sea have affected the development of regional energy trade and investment for two main reasons:

- Existing treaties – of which the main one is the 1940 Treaty of Commerce and Navigation between the USSR and Iran – do not clarify rights related to the energy sector, e.g. for oil and gas exploration, and do not define seabed boundaries; the validity of the 1940 Treaty was in any event challenged after 1991 by Azerbaijan, Kazakhstan and Turkmenistan, and;
- The Caspian Sea does not fit easily into any of the existing categories offered by international law. It is not easily recognisable as a 'sea' subject to the UN Convention on the Law of the Sea (and only Russia of the five littoral states has ratified the Convention); it is not easy to classify as an international lake (and there are varying international practices regarding the delimitation of national sectors in such border lakes); nor can it persuasively be shown under international law that the Caspian Sea should be governed as a condominium, i.e. for common use or equal share among all littoral states.

This legal uncertainty has had implications for the development of offshore oil and gas resources, since it was not evident after 1991 to what extent and in which areas the littoral states could claim sovereignty over sub-soil resources. This led to disputes over exploration in areas claimed by more than one state. The clearest examples are the mid-Caspian Serdar / Kyapaz field between Azerbaijan and Turkmenistan, and fields in the south Caspian between Azerbaijan and Iran (notably Alov / Alborz). Turkmenistan has also claimed that parts of the ACG field being developed by the BP-led Azerbaijan International Oil Company lie in its territorial waters

Given that the Caspian Sea appears to be a specific case, the optimal way to resolve questions about its legal status would have been a comprehensive five-party agreement among the littoral states. Negotiations on such an agreement began in the early 1990s but have yet to produce an agreement. The parties did though conclude in November 2003 a *Framework Convention for the Protection of the Marine Environment of the Caspian Sea*, which entered into force in 2006.

The chances of a clear five-party agreement have been affected by Iran's contention that Caspian offshore resources should be used in common for joint development (a position initially held also by Russia) or that, if divided, each country should receive an equal share, i.e. 20%, of the Caspian seabed.

Slow progress at multilateral level meant that the focus shifted in the late 1990s to bilateral negotiations. Russia, Azerbaijan and Kazakhstan signed four treaties in 1998-2003 settling delimitation of the seabed and subsoil. Since 2007, the improvement in relations between Turkmenistan and Azerbaijan has led to renewed bilateral discussions on energy cooperation and Caspian border issues. Bilateral agreements in the north Caspian foresee the possibility of joint development of fields that straddle national lines, and this could be an approach that will help to settle delimitation issues with Turkmenistan.

State practice since 1991 has strengthened the right of littoral states to develop oil and gas resources in their national sectors. The same is not yet true of sub-sea pipelines between national sectors. Although the Caspian Sea contains thousands of kilometres of pipeline, none of these connects the respective areas of different coastal states, and all current trans-Caspian energy trade is by tanker. Russia and Iran insist that any 'international' Caspian sub-sea pipelines must have the approval of all littoral states and have also raised concerns on environmental grounds; the opposing view is that there should be no obstacle to connect the pipeline systems of two coastal states that have settled their respective claims to the seabed.

Summary: Legal questions about the status of the Caspian Sea have on occasion been presented as a major obstacle to Caspian energy investment and trade. In practice, legal uncertainty has hindered but has not prevented oil and gas development. An overall legal framework for the Caspian Sea would be useful, but does not appear to be imminent. Bilateral political relationships are likely to be more important in settling outstanding legal questions and determining the direction and nature of future oil and gas flows across the Caspian.

Nabucco	
Route:	Turkey - Bulgaria - Romania - Hungary - Austria
Distance:	3 300 km
Capacity:	initial 8 bcm/y, up to 31 bcm/y
Estimated Cost:	EUR 7.9 billion
Earliest Completion Date:	2013 (for initial capacity)

The Nabucco project represents a new gas pipeline to connect European markets with gas supplies from the Caspian region and Middle East, thereby opening up the fourth supply corridor for natural gas into Europe. The pipeline would also allow the transit countries to benefit from supply diversification, as the majority of them depend on only Russian supplies through one supply route.

The project has been in gestation for over six years. The Nabucco Pipeline Company, established in 2004, has six equal shareholders, the energy companies OMV (Austria), MOL (Hungary), Transgaz (Romania), Bulgargaz (Bulgaria), BOTAS (Turkey), and since February 2008 RWE (Germany). The pipeline has been designed to transport a maximum amount of 31 bcm/y. Following a development phase until the end of 2009, construction is envisaged in two stages from 2010, with the pipeline becoming operational in its first stage from 2013. For the first stage, of 8 to 10 bcm/y, the project developers estimate that sufficient gas is available in the Caspian region.

The second stage, which will take the pipeline to full capacity, is expected to come on stream by 2019. To expand into the second stage, it will be necessary to access new supplies from the wider region, and it is at present not clear which of the various options proposed for the project may materialise as real supply. By pushing the second stage out beyond 2015 the developers assume that some of the current political tensions in the region will have subsided, and access to supplies will become easier as a consequence. It is also assumed that for the second phase, sufficient investment in gas production is done in the region in order to fill the pipeline. According to the Nabucco Pipeline Company, the potential supply sources for the pipeline are "Azerbaijan, Egypt, Russia, Iran and even from Iraq at a later point in time. Furthermore it remains to be seen if also gas from Turkmenistan and Kazakhstan will be linked with the Nabucco pipeline system."

The pipeline length is foreseen to reach approximately 3 300 km, starting at the Georgian/Turkish and/or Iranian/Turkish border, with 2 000 km crossing Turkey, and sections of 390/400/460 km crossing Hungary, Bulgaria and Romania. The pipeline will end with a 46 km connection from Hungary into the Baumgarten gas hub in Austria, whence gas will be entering the European grid to be further transported through Austria to the central and western European markets. In each of the transit countries the pipeline will be owned by a national Nabucco company, working under contract with Nabucco International, the owner of the marketing rights or transportation capacity of the pipeline, and responsible for its commercialisation.

During 2007 and 2008, major milestones have been and are expected to be met by the Nabucco project. At the end of 2007 the owner's engineer was appointed to begin detailed technical planning, and applications for TPA exemption were submitted to the regulators of the five Nabucco countries. An intergovernmental agreement between the five Nabucco countries is under negotiation, with the provisional aim to conclude the negotiation by the end of 2008.

Greece-Italy Interconnector *(second stage of Turkey-Greece-Italy Interconnector)*	
Route:	Greece – Italy
Distance:	600 km onshore, 205 km offshore
Capacity:	total 11 bcm/y, of which 8 bcm/y Greece-Italy
Estimated Cost:	EUR 0.6 billion onshore, EUR 0.3 billion offshore
Earliest Completion Date:	2012

The Turkey-Greece-Italy Interconnector (TGII) natural gas project aims to link Turkey to Greece and then Italy. In 2003, Turkey and Greece signed an IGA for the first stage of the project, followed in 2005 by an agreement between Greece and Italy. A tri-lateral IGA was signed by Turkey, Greece and Italy in July 2007 that defined the overall commercial and legal framework for gas trade and transit for the TGII. Volumes of gas supplied along the TGII are expected to rise to 11 bcm per year in 2012, with 8 bcm supplied to Italy and the remainder to Greece.

The first stage of the pipeline, the Turkey-Greece Interconnector, was commissioned in November 2007 following an official inauguration by the prime ministers of Greece and Turkey. This interconnector is a 36-inch pipeline (296 km, including 211 km in Turkey) that links Turkey (Karacabey) to the Greek grid (Komotini). The initial transportation capacity is 3.5 bcm per year. The project cost about EUR 200 million and was funded by Turkey's BOTAS, DEPA and EU structural funds (29% of total construction costs).

The second stage of the pipeline, the Greece-Italy Interconnector, is a much more ambitious 805 km pipeline to connect Greece (Komotini) and Italy (Otranto). The onshore section within Greek territory is around 600 km in length and is to be constructed by the Greek TSO (DESFA). In addition, there is an offshore section of around 205 km that will cross the Adriatic Sea. Edison, Italy's second-largest power company, and DEPA are 50/50 partners in the offshore section of the TGII, also known as the "Poseidon" pipeline.

The Greece-Italy Interconnector is expected to be operational in 2012. Initial transportation capacity in the offshore Poseidon pipeline is scheduled to be around 8 bcm per year and will be reserved to Edison (80%) and DEPA (20%) for 25 years. With the approval of the European Commission, the Greek and Italian governments (along with the relevant regulatory authorities) agreed to grant the two operators third-party access exemption on the full capacity of the Poseidon pipeline for the same duration. In exchange, 10% of volumes are to be allocated to the emerging Italian trading hub. Additional transportation capacity will be available to third parties through an open season procedure.

Trans-Adriatic Pipeline (TAP)	
Route:	Greece – Albania – Italy
Distance:	385 km onshore, 115 km offshore
Capacity:	10 initial, up to 20 bcm/y
Estimated Cost:	EUR 1.5 billion
Earliest Completion Date:	2012

The Trans Adriatic Pipeline (TAP) is a project being promoted by the Swiss Elektrizitäts-Gesellschaft Laufenburg (EGL) and Norway's StatoilHydro. EGL signed an agreement in February 2008 with StatoilHydro to establish a 50/50 joint venture to develop, build and operate the TAP. A final investment decision is anticipated in the second half of 2009, with the earliest date for completion being 2012. TAP seeks to establish a link between Southeast Europe and south Italy, where EGL operates large natural gas-fired power plants.

The preferred option is to tie-in to the existing Greek national gas transmission system and build a spur line across Albania as a means of accessing future potential natural gas storage facilities in Albania, then crossing the Adriatic Sea at the shortest distance from Albania to Italy. In addition to enhancing diversification of European natural gas supply, the TAP project would provide low transportation fees into the EU gas market and facilitate rapid connections to existing gas networks. The project would support gasification and development of Albania, and potentially - through a separate spur line along the Balkan coast towards Croatia (the Ionian-Adriatic Pipeline) - promote the development of a broader regional gas market in Southeast Europe.

Basic engineering work for the TAP project was completed in 2007. The pipeline's right-of-way and permits are expected to be secured in 2008, with complete detailed engineering and procurement following on.

The project has a number of unresolved questions, the most important being a lack of clarity on the supply side. To date, the only 'firm' commitment is a contract signed in March 2008 between EGL and the National Iranian Gas Export Company to supply up to 5.5 bcm of natural gas through the existing Iran-Turkey link for a 25-year period. Deliveries under this contract depend on the availability of Iranian gas for export and upon securing the necessary gas transportation rights through Turkey. Some other possible natural gas sources (e.g. Russia's Blue Stream) are subject to restrictions on re-export from Turkey; other Caspian sources are uncertain for the time being or may be committed to other projects. That said, StatoilHydro's 25.5% stake in the Azeri Shah Deniz field and its commitment to TAP have improved the project's credentials as an outlet for Caspian supply.