The dynamics of natural gas supply coordination in a New World
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Chapter 6
The ‘inner’ gas market integrators

6.1 Introduction
As has been indicated previously, the interregional gas market is predisposed to an oligopolistic market structure simply due to the distribution of gas reserves. The developments described in the previous chapter as far as gas market structure, trade and pricing are concerned, are likely to be dominated in the long run by a limited number of countries. A large portion of these gas reserves, some 75 percent, lies in countries where the state decides on the timing and conditions under which these volumes are exploited and sold. It is important to grasp the nature of the National Energy Firms (NEFs) in these countries and their strategies in order to appreciate how these actors may behave in the long run development of interregional gas market. These countries delegate the management of their gas resources to their NEFs which, for the purpose of this study, fall into two camps: the so-called ‘inner’ and the ‘outer’ gas market integrators (which are covered in Chapter 7). The inner integrators include Russia, Azerbaijan, Turkmenistan, Kazakhstan, Uzbekistan and Iran. Russia has aimed to extend its ties with Iran and already plays an important role with regard to the former Soviet countries.

These countries are grouped together as ‘inner’ integrators in this chapter because of the following reasons:
1) They are ‘inner’ gas market suppliers or potential suppliers because gas flows from these countries emanate from within the Eurasian continent;
2) they currently supply or could potentially supply gas mostly by pipeline (but in the medium- to long-term aim to develop LNG exports or have already done so to a limited extent);
3) as a result, despite accounting for some 45.2 percent of known conventional gas resources [IEA 2008d; BP 2009], these countries play a limited role in interregional gas trade (though this may change in the future);
4) in one manner or another, they are involved in the web of complexities of the landlocked Caspian Sea region (where Russia and Iran have a special relationship), either as landlocked states themselves or as important stakeholders in the region’s development;
5) The categorisation of this group of countries in this manner encompasses both Russia and Iran, which have a number of common interests on the Eurasian continent, differing fundamentally in that respect from other gas-exporting countries outside this group.
All the country reviews in this chapter are organised in a similar fashion: they respectively cover gas reserves and balance, gas sector developments, gas export ambitions and sales strategy as well as ties to Russia and Gazprom, where applicable. Section 6.2 covers Russia, where oil and gas reserves have been covered in Chapter 3 (in an effort to build the case for an integrated Russian gas strategy). Section 6.3 summarily covers the former Soviet republics: Azerbaijan, Turkmenistan, Kazakhstan and Uzbekistan. Section 6.4 deals with Iran, also one of the inner integrators, with which Russia has a geopolitical relationship rather than merely geo-economic one. For this reason, Section 6.4 includes a small section on the geopolitical dimension of the Russia-Iran relationship.

6.2 The Russian Federation

Having concluded in Chapter 3 that Russia wants to build on its natural resources to achieve a relative advantage, this chapter is essentially a follow up of this line of argumentation at a company level, with a focus on Russia’s gas sector. Both Russia, as a principal, and Gazprom, as an agent, operate in a space with geo-economic opportunities and constraints. Russia as a state can influence the boundary solutions for Gazprom, both in terms of domestic and foreign policies. This may help secure, for example, gas flows on the Eurasian continent, which was once part of the Soviet system of production and distribution. Understanding Russia’s priorities and goals as well as its export strategy with respect to current and new potential markets will enable one to understand how it should carefully balance internal versus external focal points.

Internally, Russia has to ensure a stable and reliable revenue stream from its natural resources, partly in order to plan and guarantee investments in other sectors with the aim of modernising and diversifying the Russian economy. The Russian government has to provide incentives so as to allocate gas production areas to both Gazprom and other Russian gas firms (i.e., independent gas producers\(^{158}\)). In addition, Gazprom must live up to its public service obligation to supply Russian citizens with relative low-priced gas (although this is planned to change).

Externally, Gazprom aims to maximise its revenues, which takes into account both access to markets (possibly via vertical integration), as well as possible moves to do the same by rivals. The growing import-dependence of the European market(s) presents Russia with an opportunity to maintain or expand market share even as it seeks to export to large and diverse gas markets, such as China and the US. Russia is shifting from a regional, captive supplier to a more global one, both by pipeline as well as LNG.

\(^{158}\) The term ‘independent’ has become increasingly unsuitable since Gazprom formed strategic relationship with and has taken (minority) equity stakes in these companies [Stern 2009b].
Section 6.2.1 is an overview of Russia’s gas reserves and current gas balance. Section 6.2.2 provides an impression of Russia’s gas sector in terms of revenues, institutionalisation, decision-making, and foreign participation. In Section 6.2.3, attention is paid to Russia’s domestic gas needs and strategy. Section 6.2.4 addresses Russia’s gas export ambitions by pipeline and LNG flows to the CIS, European, Asian, and the US markets. Section 6.2.5 provides the main uncertainties related to Russia’s merit order.

### 6.2.1 Current Russian gas balance

Russia’s gas reserves and how they compare to oil reserves was covered in Chapter 4. It produced 657 bcm in 2008, which is more than 20 percent of the world’s total [IEA 2009a]. Domestic Russian gas consumption amounted in 2008 to 462 bcm, which makes Russia a significant gas consumer, the second largest after the US [IEA 2009a]. According to Gazprom’s data, Russia exported 170 bcm and 83 bcm in 2008 to Europe and the CIS countries, respectively, through Russia’s export infrastructure, linking it first with CIS and then with European. These volumes were accompanied in 2008 by 59 bcm worth of imported Central Asian volumes by Russia and then either consumed domestically or re-exported [Nemtsov and Milov 2008; Gazprom 2009a]. In 2008, Gazprom accounted for 75 percent of total Russia’s production, see Figure 6.1.

**Figure 6.1 Russia’s gas balance in 2008**

| Source: own analysis, IEA [2009] for domestic consumption and production; Gazprom [2009] for exports, imports and Gazprom’s production. | Imports: Turkmenistan (38.1 bcm); Uzbekistan (12.8 bcm); Kazakhstan (8.6 bcm). | Note: Totals may not add up due to rounding. Gazprom’s data calculated in European bcm’s. Production from independents is assumed at: domestic production minus Gazprom’s production. |

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* Imports: Turkmenistan (38.1 bcm); Uzbekistan (12.8 bcm); Kazakhstan (8.6 bcm).

Note: Totals may not add up due to rounding. Gazprom’s data calculated in European bcm’s. Production from independents is assumed at: domestic production minus Gazprom’s production.

As far as the domestic reserve distribution and production within Russia are concerned, Gazprom controls roughly 56 percent (28.9 tcm), implying that it controls 13 percent of the world’s gas reserves. The so-called ‘independent’ gas producers control the remaining share of Russia’s reserves, 44 percent (18.9 tcm). The most important production areas in the Russian gas industry are those which have been producing for decades, located in Western Siberia, south of the Yamal area in the Nadym-Pur-Taz (NPT) area, good for some 80 percent of Russia’s gas production. The Russian gas industry is at a cross-roads as it must shift production from these mostly mature production sites to the potential producing areas in parts of Eastern Siberia, the Far East and in the region north of the Arctic Circle as well as other parts of the Yamal peninsula [IEA 2008c]. There are three categories of major gas fields located in various provinces: (1) major gas fields which are in decline; (2) those which have reached a plateau production profile; and (3) the ‘new’ gas fields, often in new gas provinces at a considerable distance from Russia’s current infrastructure. See Map 6.1 for a geographical overview of the most important gas fields in (and outside) Russia.

**Mature fields and production areas**
The mature fields include the super giant gas fields south of the Yamal peninsula, which have provided the bulk of Russia’s gas production during the days of the Soviet Union, i.e., Medvezhe (2.69 tcm), Urengoy (2.5 tcm), Yamburg (2.6 tcm). These fields are also known as the ‘big three’, and are in a significant decline at a rate of some 20 billion cubic meters per year (bcm/y), - ‘very mature’ in geological terms [Stern 2005].

**Fields with a flat production profile and brownfields**
Most of the relative ‘smaller’ fields have entered in a flat production profile. Some of these fields, mostly located in Western Siberia, offer possibilities of brownfield investments to increase production in order to hold up the decline in the big three fields (sometimes mentioned as the Russia’s small field policy). Zapolyarnoye is the most significant, it has peaked as recently as 2005 at 100 bcm/y and is currently also entering its decline [Stern 2009b]. Brownfield investments in the NPT area are another option in the shorter-term to accommodate falling production rates. Of additional importance are the resources at the Obskaya- en Tazovskaya bays, south of the Yamal peninsula, also in western Siberia near the ‘supergiant’ Yamburg field, which may add their weight of 2 tcm worth of reserves to supplementing production from the Yamal area [Gazprom 2006].

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59 Roughly 75 Percent of Russia’s gas fields are concentrated in 20 (ultra) gigantic deposits (more than 1 tcm), mostly controlled by Gazprom. In addition, there are dozens of the ‘large-scale’ fields (0.3-1 tcm) and more than 600 medium and small fields (about 10 bcm) (Zhiznin 2007).

60 These fields are all close to the existing infrastructure, and as was mentioned also, they are therefore relative more “economically practicable to develop” [Gazprom 2006, p. 35]; [Gazprom 2008b, p. 40].

61 These fields are estimated to have a production potential of up to 82 bcm/y [Stern 2009b].
The new gas provinces:

The main ‘new’ gas provinces are parts of Western Siberia, Yamal, East Siberia, Sakhalin and the Barents Sea, which includes the next generation of very large gas fields [Stern 2009]. The Bovanenskovkoye (3.2 tcm) and Kovykta (1.9 tcm) gas fields, amongst a number of other, smaller gas fields and constellations of gas fields, are those currently earmarked for either domestic consumption or exports. The Shtokman gas field (3.6 tcm), the equivalent of Norway’s entire proven resource base, is located in the Barents Sea. According to the latest plans, gas from Shtokman is expected to come on stream in the late 2010s, in 2016 with pipeline and in 2017 with LNG volumes to Europe and the US [Platts LNG Daily 2010].

Given their size, the reserves at Yamal (e.g., Bovanenkovskoye and Kharasavei) could form the bulk of Gazprom’s production well into the next decades. The collective output from Yamal at Gazprom’s accounts is estimated at 135-175 bcm/y by 2020, and 310-360 bcm/y by 2030. The Yuzhno Russkoye oil and gas deposit (1 tcm) is due to produce 25 bcm by 2009 at design capacity and is tied to the Nord Stream project (see also Case 3 in Chapter 10) [Gazprom 2009a]. Gas from the Kovykta field and other fields in Eastern Siberia and Far East (such as Chayandinskoye) may be put into production for the development of Russia’s domestic market. This is likely to be done in combination with exports by pipeline to Asian countries, such as China, South Korea and Japan (see Section 6.2.4).

For a more detailed account of possible Russian gas production (including old, plateau and new fields) by region to 2030, see Figure 6.2 below. In addition, production from independents is estimated to become substantial in Russia’s supply portfolio: from 17 percent in 2008 to almost 25 percent in 2030. Imports from Central Asia, mainly from Turkmenistan and Kazakhstan, are also estimated to grow due to newly-signed contracts (70-100 bcm/y by 2010; see Section 6.3) [Stern 2009b]. By 2008, these imports had become relatively more ‘expensive’

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62 The location of the gas fields in remote areas far from the main UGTS areas are known for their harsh climatic conditions involving permafrost and, worse yet, thawing permafrost [Stern 2009b].
63 Previous plans for Shtokman called for gas production to start in 2013 and LNG production in 2014. The first phase was expected to reach total production of 23.7 bcm [Platts LNG Daily 2010]. The first phase of the field will be developed by the Shtokman Development Company, where Gazprom is the main shareholder (51 percent) and Total (25 percent) and StatoilHydro (24 percent) have minority stakes.
64 By 2011, production from Yamal’s Bovanenkovo field is expected to reach 8 bcm/y (which will increase to 140 bcm/y in the long-term, according to Gazprom) [IEA 2009b].
65 The frontrunners amongst the independents in 2007 were Novatek (28.5 bcm), Rosneft (16.2 bcm), Lukoil (14.3 bcm), Surgutneftegaz (14.1 bcm), and TNK-BP (10.1 bcm) [Stern 2009b]. A somewhat artificial division can be made between the independent gas companies as follows: companies whose main business is oil but have significant interests in (non)associated gas, which includes Lukoil, Rosneft, Surgutneftegaz and TNK/BP. Then there are companies whose main hydrocarbon reserves and business are gas-related, these included mainly Itera and Novatek, but including all the companies that comprise the Union of Independent Gas Producers (Soyurgaz). Another category includes companies in which Gazprom has a substantial shareholding, such as Sibur and Purgaz.
66 However, the amount is uncertain due to lower Turkmen exports to Russia following an explosion in the CAC pipeline. It might be possible that Russia will import a substantial amount of gas from the gas field Shah Deniz II in Azerbaijan (also see Section 6.3). This is not included in Figure 6.2.

113
due to gradual price increases to match European levels in 2009. This means that gas from Central Asian can only be sold at a substantial loss within Russia [Stern 2009b]. It should be noted that Figure 6.2 is but one possible projection. There are a multitude of scenarios imaginable, which may shape Russia’s supply portfolio differently, and these are subject to a number of uncertainties which are discussed in Smeenk [2010].

Figure 6.2 Russia’s supply portfolio: A possible projection

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For instance, CERA estimates that gas production will be lower after 2014, compared to UBS’s [2008] projection, largely as a result of lower production from the Yamal fields. Gazprom sets out targets of 610 bcm-615 bcm/y by 2015 and 650-670 bcm/y in 2020. By 2020, according to Gazprom, new fields will account for around 50 percent of Gazprom’s gas production. This would mean an increase in its production of 300 bcm/y during 2008-20 [Stern 2009b]. Stern [2009] projects a production level of 480-580 bcm/y for Gazprom and 150-200 bcm/y for non-Gazprom producers (gas supply from the UGTS only). Lukoil envisages to produce 40 to 50 bcm/y from its gas fields in Russia by 2015, the bulk coming from the Bolshekhetskaya depression group of fields in Western Siberia. Rosneft should bring its giant Kharampur field onstream after 2012, yielding 27 bcm/y by 2015 [AGC 2008a].
The development costs for all these new fields are tremendous, costing in the tens of billions of dollars over a period of at least twenty years [Gazprom 2009a]. Thus massive greenfield investments are required, which include not just production costs but also infrastructural costs for link-ups with the United Gas Transmission System (UGTS) as well as processing facilities.  

6.2.2 Institutionalisation of the Russian gas sector

In order to try to balance earnings from the oil and gas sectors and the differences between CIS and European gas market, the Russian leadership under Putin intends to employ an integrated long-run energy strategy. Upon observation, one can discern that Russia has come to see gas as a spearhead for its long-run economic development. The lack of control exercised during the politico-economic crisis of the 1990s led Putin to restore some measure of order through state-centred reforms, returning Russian society to a state of relative stability (also see Chapters 3).

The reorganisation of the gas industry during the 1990s and Putin’s restructuring included a shift from the planned production system of Gosplan to a more market-based, profit-maximising system, embodied by Gazprom [Stern 2005]. In order to ensure a stable and reliable revenue stream from its natural resources, the Russian government has since 2004 increased state control over and ownership in its energy sector around national champions.

The higher oil prices (due to stricter OPEC production policies towards the end of the 1990s) ensured the inflow of greater export revenues, which led to a partial implementation of policies [Åslund 2007].

It is in this light that the creation of national champions was an effort, in the first instance to halt further asset stripping and embezzlement, and in the second place to reverse the overall trend of decentralisation which had set in under Yeltsin (see also Chapter 3).

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6.6 Due to neglected maintenance and refurbishments (especially during the 1990s as a result of shortage of funds and the economic chaos), large parts of the UGTS in Russia (and other CIS countries) are in a deplorable state and need to be refurbished. For example, by 2001 the capacity of pipelines exporting gas from NPT had fallen from the design capacity of 577.8 bcm/y to 518 bcm/y [Mitrova et al. 2009; Stern 2009b]. Concerning a new project, for example, in 2008 the total development costs (production and pipeline and LNG transportation capacity) for Shostokman alone are estimated to exceed $40 billion [Stern 2009b].

6.7 For a historical overview of the institutionalisation of the Russia’s gas sector, see Part II in Smee nk [2010]. In Putin’s study (‘Strategic Planning of Replacement of Regional Mineral Reserves in Conditions of Forming Market Relations’), Putin argued already that the transfer of control of Russian strategic sectors, such as oil and gas, to private owners was a costly mistake. This experience from the nineties should be reversed – not necessarily by re-nationalisation. For Russia, from Putin’s point of view, the mixture of state-private ownership has to be the best solution for strategic companies, so that the state can regulate these sectors. According to his study, Russia should welcome foreign investors for their knowledge and financial resources [RussEnergy 2005].

6.8 One of the most prominent cases was the arrest and conviction of Yukos’ chief executive Michael Chodorkovski. This led to the dismantling of the Yukos’ Empire. Moreover, Russia had limited the access to its resource for IEFs [Fredholm 2005].

6.9 However, Gazprom continues to spend its money in a questionable fashion by taking stakes in non-core businesses and selling some entities below market value [Hartley and Medlock III 2008; Nemtsov and Milov 2008]. Additionally, Putin
are Gazprom in the gas sector and Rosneft and Lukoil in the oil sector. The Kremlin has also tried to assert greater control over the oil industry via Gazprom, and thus forming Gazprom into a NEFs [Victor 2008]. These state-controlled companies can be used by the state as an instrument of internal and external policies [Russian Ministry of Industry and Energy 2003]. Decentralisation during the 1990s was felt especially in the oil sector, while the gas sector remained centralised with a large minority Russian government stake, changing little between 1993 and 2004. Putin had set out to strengthen the government’s control over Gazprom in an apparent conviction that privatisation and free market capitalism in key Russian sectors was not in Russia’s national interest. In addition, Gazprom argued that any degree of vertical separation would erode its economies of scale and the functioning of the entire production, transport and distribution system [Mitrova 2009]. With the new stake of 50.002 percent in the vertical-integrated company as of late 2005, the Russian Federation now had direct control of its operations and its management (see also Figure 6.3). The vision emerging in 2004 was that Gazprom should become a multinational oil and gas company, representing interests of the government both domestically and internationally [Stern 2005]. Becoming a multi-market player is thus one of Gazprom’s purposes, and indeed, that of the Russian government [Fredholm 2005; Gazprom 2009a; 2009b]. Ultimately, merging Gazprom and Rosneft into one single very large NEF would have been the first step in giving this NEF a position in the international oil market as well as the interregional gas market. Yet, this step has not been taken. 

established another way to ensure substantial incomes for members of government (and top managers in Gazprom) via secondary positions, besides their main (governmental) position [Business week 2009].

The ownership of the company changed remarkably little during this period, while Russian legal entities owned a further 35 to 40 percent, Russian individuals, including employees owning 15 to 20 percent and foreigners between 10 and 12 percent [Goldman 2008]. Former Gazprom’s CEO, Vyakhirev, however, was not in full control of the company and significant asset stripping weakened the company as Gazprom executives established their own little empires at the expense of the company (see Part II in Smeenk [2010]).

The strategic goal of OAO Gazprom is: ‘becoming a leader among global energy companies by conquering new markets, diversifying business activities and pursuing supply security’ [Gazprom 2009a]. At the same time ‘The main aim of the Russian Energy strategy is strengthening of competitive positions of the Russian energy industry in the world market” [Russian Ministry of Industry and Energy 2003; Zhiznin 2007].

In 2005, the Gazprom-Rosneft merger was abandoned due to the complexities in the financial architecture of the transaction and resistance from Rosneft management and their sponsors within the government [Stern 2005].
As a firm, Gazprom must take into account Russian government priorities as well as make decisions in the interest of its business continuity. From a government perspective, Gazprom can be an engine for maximising social wealth by utilising gas revenues for fuelling domestic economic growth and diversity, padding the government budget and the stabilisation fund. Developing a gas-based industry (in order to diversify its economy) may also shape Russia’s domestic gas strategy and policy. Maintaining relatively low regulated gas prices in Russia will likely play a role. From a corporate perspective, Gazprom’s role consists of maximising (windfall) profits from domestic, CIS, and other export markets. Since 2006, Gazprom officially attained an export monopoly over the gas flows from Russia to its foreign markets. Russia’s challenge in devising a gas strategy as is to balance and control a set of interlocked agents of which Gazprom is but one of several agents. Without the independent gas producers and the Central Asian producers (Turkmenistan, Kazakhstan and Uzbekistan) and in the future possibly Azerbaijan, Gazprom may probably not fulfill its export obligations to Europe.

**Decision-making process within the gas sector**

Increasingly, since Putin came into power, Gazprom’s strategy became an important priority of Russia’s government: “Gazprom became the first business structure in which Putin by deliberate plan seized the commanding height” [Nemtsov and Milov 2008, p. 4]. On a strategic
level within the Russia’s gas industry, decision-making is very centralised, and largely influenced by the government [Mitrova 2009]. As mentioned by Mitrova [2009], Gazprom operates in many ways as a ‘quasi-ministry’, like it was during the Soviet times.

**Figure 6.4** A schematic schedule of the decision-making process in the Russian gas industry

In principal, the administration of the Russian Federation (including the Kremlin) is responsible for strategic decision-making. The administration is led by the president (currently Dimitri Medvedev), which in turn is advised by the Presidential Secretariat. The Prime Minister’s Cabinet and relevant ministries, Duma and the Senate, influence this process, as well as members of Gazprom’s management board.\(^{176}\) Gazprom is largely responsible for the implementation of Russia’s gas strategy. Informal links between the different governmental and corporate bodies, such as between the president and the Prime Minister (Medvedev and Putin respectively), make the process of decision-making comparatively opaque. Figure 6.4 gives an approximated overview of Russia’s decision-making in the gas industry.\(^{177}\)

\(^{176}\) A large number of people working at Gazprom are part of Putin’s network. The chairman of Gazprom’s board of directors, Viktor Alexeevich Zubkov, for example, is also the first Deputy Prime Minister of Russia. The role of Sechin (Deputy Prime Minister and chairman of Rosneft’s board of directors) is relatively more important for decision-making within the oil sector.

\(^{177}\) This overview is designed to provide a simplified, perhaps even oversimplified impression of decision-making in the Russian gas sector. Informal and formal forces may also be at play to such an extent that it is beyond the scope of consideration for this study.
Foreign participation in Russia’s gas sector

After the dissolution of the Soviet Union and the first years of transition until mid-1990, the Russian energy sector became relatively open for foreign investors, especially the oil sector.176 The gas sector remains largely centralised. However, some gas fields were developed by foreign companies, such as Royal Dutch Shell, Mitsui and Mitsubishi in Sakhalin II (founded in 1994) and BP via TNK-BP (founded in 2003) in the Kovykta field. A number of foreign companies met difficulties and had to reduce (e.g., Royal Dutch Shell in Sakhalin II) or even cease their activities in Russia. The traditional form of foreign participation in development gas fields was subject to conditions specified in production sharing agreements (PSAs). Under Putin, the priority has been given to other contractual forms, particularly to public-private partnership (PPP), which is a means of better organising the development of resources under conditions determined by the state [Van der Linde et al. 2007].178 In most of the large fields, Gazprom has a majority stake for strategic reasons [Mitrova 2009; Zhiznin 2007]. These foreign participations are often part of a broader cooperation through vertical asset swaps (see below). Cooperation with major foreign corporations is desirable in terms of their large financial and technological potential and corporate experience [Zhiznin 2007; Stern 2005]. The most important foreign partners, in addition to the above-mentioned companies, with stakes in the Russian gas sector are Badische Anilin- und Soda-Fabrik (BASF)/Wintershall, ENI, E.ON Ruhrgas, Total, ExxonMobil, Sakhalin Oil and Gas Development Co (SODECO), Indian Oil and Gas Corporation (INGC) and StatoilHydro [Mitrova et al. 2009; Zhiznin 2007].

6.2.3 Domestic gas needs and strategy

Russia’s primary energy mix in 2008 (684.6 Mtoe) was composed as follows: 55 percent of gas, 19 percent of oil, 15 percent of coal, 5 percent of nuclear and 6 percent of hydropower [BP 2009].179 Russia is thus a major gas consumer, where domestic demand in Russia takes up almost three quarters of Russian production, see Figure 6.1. Russian per capita consumption of gas is similar to that in Canada, but consumption per US dollar of GDP is roughly five times higher than IEA countries [IEA 2007], hinting at vastly less efficient consumption in Russia. Due to Third-Party Access (TPA) and sales restrictions, oil companies have to flare significant volumes (estimates are around 15-50 bcm/y or even more) [Stern 2005]. Russia’s economic

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176 For an extensive overview of foreign participation in Russia, see for example Zhiznin [2007], Stern [2005; 2009] and Part II in Smeenk [2010].
177 In addition, many of these PSAs were implemented solely by foreign partners [Mitrova 2009]. See also Van der Linde et al. [2007] for an overview of PPPs in Russia.
178 Another way to attract foreign investments is the (international) capital market through initial public offering (IPOs). Gazprom’s removal of limiting foreign shareholders in 2006 has resulted in a tenfold rise in market value (to more than $250 billion) [Mitrova et al. 2009].
179 For an extensive analysis on the Russian gas strategy within Russia and CIS, see for example Pirani et al. [2009], Stern [2005], IEA [2008].
growth (when measured by GDP from 1999 until the economic crisis in 2008: 5-8 percent per annum), combined with relatively low, subsidised domestic prices resulted in a high gas demand [Stern 2009b]. Gas prices are subsidised in order to provide Russian industrial and residential consumers with some leeway. In addition, low gas prices have forced other fuels out of the power generation and industrial sectors, the share of gas in Russia’s grew from 43 percent in 1990 to 55 percent in 2008 [BP 2009].

The Russian gas market itself is in transition. During the 1990s, in the aftermath of the collapse of the Soviet Union and the economic chaos that ensued, demand for gas in Russia fell substantially. With the Russian financial crises in 1993 and 1998, demand fell even further and the Russian domestic gas market was plagued with a default of payments by customers, both in the residential and industrial sector [Stern 2005]. After 1998, when the Russian economy picked up again owing in part to a devalued Russian rouble, gas demand began to rise to pre-1991 levels (from 418.2 bcm in 1991, to 352.8 bcm in 1999 and 420.2 bcm in 2008) [BP 2009]. With the onset of the 2008-2009 financial and economic crisis, Russian domestic demand significantly dampened [WGI 2009i]. Stern [2009] projects a domestic demand of 385-440 bcm in 2015.

Gazprom supplied Russia’s domestic market with 260 bcm. Further downstream, Gazprom holds ‘blocking-stakes’ in more than 70 percent of gas-distribution plants [Mitrova 2009]. The IGP’s fulfill other domestic demand, although Gazprom is increasingly trying to control the Russian gas sector [Hartley and Medlock 2008]. Deliveries from the IGP’s are almost entirely concentrated in the power and industrial sector and are not delivered to residential customers or even distribution companies [Stern 2005]. Of Gazprom’s sales in 2008, the largest shares went to non-household sectors: 32.5 percent went to power generation, 16.8 percent to the utility sector and much of the remainder to the industry sectors. Russian household consumers were responsible for 16.8 percent of the total Gazprom’s sales in Russia [Gazprom 2009a]. In the face of high domestic demand until recently, the difficulty for Gazprom has been to develop the required infrastructure to accommodate flows from the independent gas producers without running the risk of seeing empty pipelines long before they have been amortised [UBS Investment Research 2008]. Nevertheless, the independent gas producers provide Gazprom with the opportunity to share the investment burden. A growing share of gas investments in Russia is expected to come from the independent gas producers, contingent upon them gaining access to Gazprom’s transmission system [IEA 2008c].

For example, in 2006, Gazprom purchased a 20 percent stake in Novatek and had established ‘strategic partnerships’ with Lukoil and Rosneft [Hartley and Medlock III 2008].
In 2006 the Russian gas exchange (Mezhregiongaz) was launched with the aim of liberalising the Russian gas market and introducing market principles in the traditionally state centred Russian energy supply system. The volumes traded thus far are only at experimental levels not exceeding 10 bcm in 2007 (less than 2 percent of gas sold in Russia) and constitutes thus only a small step towards liberalisation [Stern 2009b]. The liberalisation allow Gazprom and the independent gas producers to sell on spot terms when prices are well above those set for the domestic market and securing the IGPs’ access to the pipeline network.

In addition, with the proper legislation and tax structures in place, it is possible to provide an incentive to the IGPs to develop non-strategic fields, channelling the volumes to foreign markets through Gazprom. Gazprom in turn could then be in charge of maximising the value of these volumes and distributing the resulting added value to the independent gas producers as a means of sharing the risks and benefits. The proposal for this mechanism has been put forward to the Russian Duma [CIEP 2008]. There currently still are bottlenecks when it comes to channeling non-Gazprom gas to Gazprom’s pipeline network: the IGPs are force to flare some 40 bcm worth of gas production because Gazprom does not yet offer favorable access to its pipeline network [Financial Times 2009f]. With gas oversupply in Gazprom’s export market(s) in 2009, Gazprom is in a difficult position, as export monopolist to accept these volumes.

The relatively low current domestic gas prices contribute to the overall importance of energy for the Russian economy, manifested in the national accounts, distorting efficiency incentives and discouraging investment in Russia’s gas sector [Åslund 2007; Gazprom 2009a]. Long demanded by the IMF, WTO and EU, in November 2006, the Russian government took the decision to gradually increase regulated gas prices (with a difference between the industrial and household prices), so that by 2011 they will reach export parity with Europe, excluding trans-

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93 A gas exchange (or hub) will allow gas prices to float as they do on European hubs, properly reflecting demand and supply conditions. The amounts of gas exchanged should reach 15 bcm by the end of 2008 [PIGR 2007].

94 Initial 2006 deals indicated an average price of $60/mcm, or $1.70/Mbtu, compared with the average domestic price of $1.25/mbtu, reflecting the willingness of some industrial consumers to pay more for volumes than state-regulated prices for volumes beyond those provided by Gazprom on a long-term basis [WGI 2008d]. Besides the introduction of spot sales, long-term contracts for industrial customers were introduced. Gazprom insists that the general scheme on the country’s gas sector development until 2030 should be adopted before the implementation of regulations on non-discriminatory, third-party access for independent gas producers to the pipeline system [WGI 2009i].

95 Indeed, Russia’s Federal Antimonopoly Service (FAS) has been instructed by the cabinet to amend the Gas Export Act in order to enable Gazprom to share export profits with the independent gas producers [Kommersant 2008b].

96 Gazprom has invested heavily over the last few years to expand the Urengoy transportation system to enable the independent gas producers to boost output from the region’s fields [UBS Investment Research 2008].

97 Rosneft has even begun a court case against Gazprom in order to compel the company to allow access to its pipeline network.

98 During the 1990s the gas sector moved away from a principle of ‘cost-plus’ pricing to de facto ‘price-cap’ regulation [Mitrova 2009].
mission costs and customs duties [Stern 2009b; Gazprom 2008a]. According to Stern [2009], this policy will have some important consequences:

- sales of gas from the relatively more expensive new fields (such as Yamal) could be profitable on the domestic market;
- there will increasingly be an incentive for (particularly independent) producers to maximise its production and sales for the domestic market;
- investments in efficiency and energy saving will be more profitable;
- In the longer-term, a netback parity with West European prices would make the domestic Russian market more attractive than exports (due to additional transport costs). Russia’s export potential is thus directly linked to domestic developments not only in terms of domestic Russian prices but also Russia’s primary energy mix. The most important domestic concern of the Russian government is ensuring that domestic demand in Russia is met first, and Gazprom as an agent of the state, is tasked with a PSO in this respect. This is a political as well as an economic priority for the Russian government [Gazprom 2008b]. Relatively high gas prices, e.g., by mid-2008, but also the current economic downturn could delay the current scheme of gradual gas price increases [Stern 2009b].

6.2.4 Gas export ambitions and strategy

During the late Soviet times, Russia was dependent on Europe as a hard currency-earning market, while providing its CMEA and Soviet allies with cheap, subsidised energy. Gazprom’s current exports should be seen as split into European and CIS exports. Within Europe, one can distinguish former CMEA countries and West European countries and Turkey. Russia benefits not only from its location and the size of its resource base, but also from its status as the key incumbent in Europe, where it can affect the supply-demand balance such that it can have knock-on effects in the Atlantic LNG basket [Barnes et al. 2006; IEA 2007a]. As mentioned above, Russia has, at the political level as well as in the commercial sense, more global ambitions. Specifically for its export markets, Gazprom aims to [Zhiznin 2007]:

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189 See Table 2.9, p. 74, in Stern [2009] for the estimated average Russian gas prices from 2007 to 2011. The approach of relatively gradual and controlled increases aims to support the government’s general anti-inflationary policy, including tight monetary supply [Mitrova 2009].

190 Mitrova [2009] suggests a rule of thumb for the power sector that gas-saving measures will become economically justified when prices are above $100/mcm.

191 From Russia’s governmental point of view, exports to the foreign markets, however, are still more attractive to Russia (as a government), due to export duty revenues (30 percent on exported gas), except for the member of the Customs Union (Russia, Belarus and Kazakhstan) [Mitrova 2009]. Nevertheless, in the short- and mid-term, import prices of Central Asian gas are expected to be higher than Russia’s domestic prices [Stern 2009b].

192 For a historical overview of Russia’s export strategy, see Part II in [Smeenk 2010], Stern [2005; 1999].
1) secure its present market position in price and volume terms;
2) enter new regional markets, such as Asia-Pacific and the US market by pipeline and LNG exports;
3) evolve new business models of sales, such as self-contracting and integrate vertically by controlling storage and downstream activities closer to the market;
4) explore short-term contracts and spot trade in Europe;
5) minimise its reliance on troublesome transit countries such as the Ukraine and Belarus, collect debt from and increase the profitability in its CIS export markets;
6) ensure that it remains the only economically viable transit route to Europe for Caspian gas; and
7) developing upstream exploration and production opportunities in other countries.

The diversification of Gazprom’s export activities is schematically portrayed in Figure 6.5.

**Figure 6.5 Diversification of Gazprom’s export activities**

<table>
<thead>
<tr>
<th>Gazprom’s gas sources</th>
<th>(New) pipeline facilities</th>
<th>Export markets</th>
<th>Level of market penetration</th>
<th>Types of contracts</th>
</tr>
</thead>
<tbody>
<tr>
<td>* Own produced gas</td>
<td>* Ukraine transit</td>
<td>* CIS countries</td>
<td>* Wholesale gas sales</td>
<td>* Long-term contracts</td>
</tr>
<tr>
<td>* Gas produced by JVs with Gazprom (in and outside Russia)</td>
<td>* Direct connections to CIS/Baltic/Finnland</td>
<td>* Europe</td>
<td>* Midstream activity</td>
<td>* Short-term contracts</td>
</tr>
<tr>
<td>* Gas from IGPs</td>
<td>* Yamal-Europe</td>
<td>* Asia-Pacific</td>
<td>* Gas sales to end users (i.e. Gazprom M&amp;T)</td>
<td>* Spot sales</td>
</tr>
<tr>
<td>* Gas from the Caspian region</td>
<td>* Blue Stream</td>
<td>* North America*</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Nord Stream*</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* South Stream*</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Altai pipeline*</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Sakhalin</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Shtokman*</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* (Yamal)*</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Sakhalin-Khabarovsk-Vladivostok-pipeline*</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Far East pipelines*</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Under construction/committed or planned/proposed.
Source: own analysis, based on RPI [2005].

**Near abroad: export to CIS markets**
Gazprom’s gas sales in the CIS were 83 bcm in 2008 [Gazprom 2009a]. Most of the CIS sales is concentrated in Russia’s transit countries: Ukraine (61 percent) and Belarus (23 percent).

---

193 Some 80 percent of Russia’s gas exports to Europe now travel through the Ukrainian network.
194 Additional aims of Gazprom, although less related to its export strategy, are (1) lower dependence on import equipment and services, and (2) attracting foreign investments [Zhiznin 2007].
cent). Other less important export markets are Kazakhstan (10 percent), Moldova (2 percent), Armenia (2 percent) and Georgia (1 percent) [Gazprom 2009a]. Although the energy mix differs by CIS country, gas is an important contributor to their energy needs. The share of gas in the Ukraine’s energy mix is more than 40 percent, whereas in the case of Belarus this is almost 70 percent [BP 2009]. These CIS countries are heavily dependent on Russia’s (and other CIS’s) imports [Pirani 2009].

Gazprom’s strategic challenge in the CIS is about how to govern the increasingly complex interdependent relationships with three groups of countries in an effective way:

1) Central Asian countries and Azerbaijan, on which Gazprom’s dependence for key gas supplies could rise, as well as countries which one in some cases necessary for transit purposes (see below); 196

2) Caucasus countries where it had to compete with gas flows from Azerbaijan and Iran [Tokmazishvili 2009; IEA 2008c];

3) Ukraine, Belarus and Moldova where Gazprom will be selling gas as well as needing territory to ship gas to Europe (from Central Asia as well as Russia). Gazprom has a problematic transit relation with a number of CIS countries, which has led to various disputes (such as in 2006 and 2009) [Mitrova et al. 2009; Stern 2005]. 197

As the 2000s unfolded, several important developments in addition to a change in management saw Gazprom take CIS gas trade back under its control. This includes moving away from barter and trading intermediaries (which sold gas from Central Asia and Russia) [Pirani 2009]:

- a change in Gazprom’s supply position led to a corresponding rise in the strategic value of Central Asian gas in its future supply portfolio, although it becomes more expensive; and
- the economic recovery of CIS economies, combined with Gazprom’s new geo-economic framework (see Section 6.2), raising Russian prices and higher import prices from Central Asia, leading to a new commercial framework: more profitability and increasing export prices to the principal of European netback pricing [Yafimava 2009; Stern 2005; Mitrova et al. 2009]. 198

196 Russia’s strategy towards the Caspian region changed during the period after the collapse of the Soviet Union (see also Part II). During the 1990s, Gazprom replaced gas (barter) trade between Turkmenistan and other CIS countries (mainly Ukraine) by intermediates, like Itera. These middlemen companies captured most of Central Asian resource rents. As a result of increasing competition, combined with the strategic importance of Caspian production for Gazprom’s gas supply portfolio, Gazprom changed its strategy to a more commercial relation [Stern 2005; Victor and Victor 2006].

197 Also see Part II and Chapter 10 in Smeenk [2010].

198 In addition, the Russia-Ukraine gas disputes (in 2006, 2008, and 2009) have accelerated European netback price implementation for Ukraine [Mitrova et al. 2009]. However, avoiding vulnerability to disruptions of Gazprom’s supplies to Europe in transit through the western CIS and geopolitical considerations may delay the implementation of its netback policy in the western CIS [Pirani 2009].
Due to the maturity of CIS markets, the desire to reduce its dependency on Russian gas and its increasing convergence to European gas price, in terms of volumes, there are relatively small market opportunities in CIS markets from Russia’s perspective. On the one hand, Gazprom is attempting to secure and maintain market share by buying equity in large gas consuming components of the value chain, such as transport, power and industrial enterprises. On the other hand, it may want to keep its current contractual flexibility (e.g., Gazprom’s current volume contract with Ukraine need to be signed every year) as a tool of managing Gazprom’s supply portfolio [Pirani 2009].

Figure 6.6 Gas prices for Gazprom’s gas in different markets: 2003-2008

As far as Gazprom’s export markets are concerned, prices differ immensely by market, see Figure 6.6). As mentioned above, prices in Russia itself are regulated, and amounted to $67/thousand cubic meters ($67/mcm) in 2008. CIS and Baltic prices were $149/mcm on average, while European prices stood at $313/mcm [Gazprom 2009a]. Much of these price differences are attributable to the path-dependency aspects of a transition from Soviet-era gas

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Note: Average exchange rate RUR/US$ in 2007: 25.6; and in 2008: 24.8.
Source: Gazprom’s databook 2007; Gazprom [2009].

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Although it is difficult to predict, Stern [2009] estimates similar volumes (75-85 bcm in 2015), excluding Azerbaijan and Kazakhstan, to those of the mid 2000s.

For example, it has taken equity stakes in Armenian, Kazakh, Moldovan and Belarusian transportation assets [Mitrova et al. 2009].

Gazprom’s contract with Belarus will end in 2012 [Yafimava 2009]. The ‘commercialisation’ of Russia’s trading relation with western CIS countries could, however, entail long-term contracts [Pirani 2009].
pricing and subsidies to the current, more market oriented setting (see Part II, Smeenk [2010]).

Far abroad: export to European markets
Gazprom’s supply to Europe has increased by around 73 percent between 1990 and 2008. The sales to Western Europe (including Turkey) have more than doubled, with a relatively sharp climb since 2002 (almost 5 percent per year growth). This is not the case for Central and Eastern Europe, where Gazprom’s gas sales increased by only 1 percent between 1990 and 2008. The total sales of Gazprom in Europe were 170 bcm in 2008. In Western Europe, Germany (34 bcm), Turkey (21 bcm), Italy (20 bcm), the UK (19 bcm), France (10 bcm) were the largest European markets for Gazprom. In Central and Eastern Europe, Hungary (8 bcm), Czech republic (7 bcm), Poland (7 bcm) and Slovakia (6 bcm) are also significant markets for Gazprom. Figure 6.7 shows the development of Gazprom’s gas sales in Europe from 1990 to 2008, whereas Figure 6.8 gives an overview of Gazprom’s sales and markets share per country.

**Figure 6.7 Export volume of Gazprom to Europe: 1990-2008**

From a Russian point of view, the European gas market as a whole can be fallen into four different categories, or sub-regions: South and Southeastern Europe (SSEE), Northwestern Europe (NWE), North and Northeastern Europe (NNEE) and other Central and Eastern
European (CEE) countries. Each of these different sub-regions exhibits different gas use intensity, depends to differing degrees on Russian gas and each region has its own infrastructural level of development. As a result, Russian gas plays a disproportionally large role in terms of share and end-usage in a number of countries. Some of these countries may try to curb their dependency, which implies a decrease or limit of Russian gas imports. Figure 6.8 includes Gazprom’s market share in total gas consumption and in power generation. The absolute values of Gazprom’s market shares are greater in countries of Western Europe than in Central and Eastern Europe. In Germany and Italy, for example, Russian gas enjoys a larger market share but on average, in terms of power generation, the share is actually quite small (expect from Turkey). Both countries’ gas markets may be heavily reliant on Russian gas, but in power generation terms it is less significant. In Central and Eastern Europe the absolute volumes of Russian gas are smaller, but Russian gas has a much greater market shares in terms of total gas consumption and power generation.

Figure 6.8 Gazprom’s sales and market share in European countries in 2008

Gazprom’s sales and market share in West Europe**
In bcm in 2008

<table>
<thead>
<tr>
<th>Country</th>
<th>Sales (bcm)</th>
<th>Market Share in Total Gas Consumption</th>
<th>Market Share in Power Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>34.2</td>
<td>40%</td>
<td>5%</td>
</tr>
<tr>
<td>Turkey</td>
<td>21.4</td>
<td>35%</td>
<td>19%</td>
</tr>
<tr>
<td>Italy</td>
<td>20.2</td>
<td>24%</td>
<td>10%</td>
</tr>
<tr>
<td>UK</td>
<td>18.8</td>
<td>17%</td>
<td>9%</td>
</tr>
<tr>
<td>France</td>
<td>9.5</td>
<td>11%</td>
<td>5%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>5.0</td>
<td>8%</td>
<td>3%</td>
</tr>
<tr>
<td>Austria</td>
<td>5.2</td>
<td>6%</td>
<td>3%</td>
</tr>
<tr>
<td>Belgium</td>
<td>4.4</td>
<td>5%</td>
<td>1%</td>
</tr>
<tr>
<td>Finland</td>
<td>4.8</td>
<td>6%</td>
<td>3%</td>
</tr>
<tr>
<td>Greece</td>
<td>3.3</td>
<td>6%</td>
<td>3%</td>
</tr>
<tr>
<td>Switzerland</td>
<td>0.3</td>
<td>6%</td>
<td>3%</td>
</tr>
</tbody>
</table>

Gazprom’s sales and market share in Central and Eastern Europe
In bcm in 2008

<table>
<thead>
<tr>
<th>Country</th>
<th>Sales (bcm)</th>
<th>Market Share in Total Gas Consumption</th>
<th>Market Share in Power Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hungary</td>
<td>8.0</td>
<td>16%</td>
<td>9%</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>7.2</td>
<td>19%</td>
<td>9%</td>
</tr>
<tr>
<td>Poland</td>
<td>7.1</td>
<td>15%</td>
<td>9%</td>
</tr>
<tr>
<td>Slovakia</td>
<td>5.6</td>
<td>11%</td>
<td>6%</td>
</tr>
<tr>
<td>Romania</td>
<td>3.3</td>
<td>7%</td>
<td>3%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>2.7</td>
<td>5%</td>
<td>2%</td>
</tr>
<tr>
<td>Lithuania</td>
<td>2.5</td>
<td>10%</td>
<td>4%</td>
</tr>
<tr>
<td>Serbia</td>
<td>2.0</td>
<td>6%</td>
<td>3%</td>
</tr>
<tr>
<td>Croatia</td>
<td>1.4</td>
<td>8%</td>
<td>3%</td>
</tr>
<tr>
<td>Latvia</td>
<td>0.6</td>
<td>4%</td>
<td>2%</td>
</tr>
<tr>
<td>Slovenia</td>
<td>0.5</td>
<td>3%</td>
<td>2%</td>
</tr>
<tr>
<td>Estonia</td>
<td>0.5</td>
<td>3%</td>
<td>2%</td>
</tr>
<tr>
<td>Bosnia and Herz.</td>
<td>0.3</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Macedonia</td>
<td>0.1</td>
<td>1%</td>
<td>1%</td>
</tr>
</tbody>
</table>

* Power generation includes electricity and heat sold (data for 2007).
** Including Turkey.

Note: Total Gazprom’s sales in Europe account 169.7 bcm in 2008. Other sales, not mentioned above, are 0.5 bcm. Sales in Ukraine in 2008 are 50.4 bcm; in Belarus: 19.0 bcm; Kazakhstan: 8.7 bcm; Moldova: 2.4 bcm; Armenia: 1.9 bcm; and in Georgia 0.6 bcm.

Source: own analysis, based on Gazprom annual report [2009] (converted to European bcm’s); total gas consumption and gas consumption for power generation are based on IEA [2009].

Southwest European countries (including Spain and Portugal) could not be reach economically by pipeline with Russian gas. In the future, Russian LNG might be shipped to this region. For instance, in October 2009, Gazprom and Spanish oil and gas company Repsol have signed a MoU on cooperation in oil and gas projects.
Gazprom’s strategy is likely to hinge on the potential for growth in maximising the space for acceptable import-dependency in each sub-region, mainly in major countries in NWE and SSEE, such as Germany, Italy, UK, France, the so-called ‘Big Four’. In addition to market opportunities, Turkey has a special role, because geographically it lies in a strategic area between Europe and the Middle East as well as the Caspian region. Suffice it to say for now that Turkey is a major potential transit hub for a variety of gas flows by pipeline, primarily from the Middle East (Iraq), Caspian region and of course Russia. The NWE region offers hub trading opportunities and some storage, as does CE, while simultaneously the other regions are smaller in terms of volumes (e.g., NNEE) or depend more on LNG. In its gas strategy, Russia is reaching out to those countries with the strongest economic and commercial interests in Russia (e.g., Germany, Italy and France), while limiting to the greatest extent possible any intrusion on the part of the new EU member states [Trenin 2007]. Besides the framework of the EU-Russia Energy dialogue, as a political basis for long-term energy cooperation, Russia has established bilateral energy dialogues on governmental level with, for example, the Big Four [Zhiznin 2007]. Through these partnerships Gazprom aims to secure downstream positions through joint ventures and asset swaps (see below).

Midstream: Cooperation in storage and export route diversification pipelines

Gazprom’s Yamal-Europe, Blue Stream, Nord Stream pipelines are all ostensibly part of a strategy aimed at ensuring Gazprom’s market position in price and volume terms, as well as reducing reliance on Ukrainian transit. Notwithstanding some of the risks, miscalculations and costs, gas supplies through the Yamal-Europe pipeline have broken up Ruhrgas’ monopoly in the German market, while the Blue Stream pipeline helped establish a strong position in Turkey. The Nord and South Stream is aimed to ensure its market position at the NWE and, respectively, SSE sub-regions. In addition, by having a combination of different export routes to the European market, Russia can, in theory (and as Norway already does with its various pipelines), shift its volumes intra-regionally as

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For a further account of gas transit see Chapter 10 in Smeenk 2010 and for an overview of the strategic-economic role of pipelines from a Russian perspective, refer Chapter 11.

The offshore pipeline Nord Stream (2 times 27.5 bcm/y), connecting Russia directly to Germany via the Baltic Sea, will be linked to the UGTS in Russia, with the reserve base being the Yuzhno Russkoye field and Shstokman. See Case study 3 in Chapter 9 for an extensive overview and analysis on this investment.

South Stream, with a planned capacity of 63 bcm/y up from the initially planned capacity of 31 bcm, is a planned and proposed pipeline running from Russia over the Black Sea to Bulgaria. Two possible routes are under review for South Stream’s onshore section from Bulgaria – one, north-westwards and the other, south-westwards. The resource base for the South Stream pipeline is likely to be the Urengoy field in West Siberia or Caspian reserves [WGI 2009a; Gazprom 2008a]. Also refer to Case study 2 in Chapter 9 for an extensive overview and analysis on this investment.
and when spot and short-term prices shift, mitigate transit risks, and/or increase its bargaining position towards western CIS countries.\(^{206}\)

Additionally, the transit risks in western CIS countries could also be solved by taking majority ownership stakes and/or by Russian ratification of the Energy Charter Treaty and its Transit Protocol. However, currently Ukraine refuses to allow Russia to have a controlling stake. Meanwhile, Russia refuses to ratify the ECT treaty due to (1) the current political climate between Russia and EU; and (2) it is seen in Moscow as a threat to Gazprom’s commercial interest [Pirani 2009]. Therefore, this governance system to mobilise investment is reviewed in Russia (in addition by other stakeholders too), by treating foreign investments in its energy sector at its own sovereign discretion. As a result, in April 2009 Russia launched a new conceptual approach to a legal framework for energy cooperation. In July 2009, it subsequently decided to withdraw from the ECT with the aim of developing and proposing its own legal framework [Van Agt 2009].

Another focal point for securing capacities in pipeline and storage is to create flexibility and arbitrage opportunities. Gazprom owns pipeline capacity in Germany via Wingas, in the Interconnector (10 percent) between Belgium and the UK and has an option on 9 percent in the Balgzand Bacton Line (BBL) pipeline (from the Netherlands to the UK).\(^{207}\) Various countries in Europe have storage capacities, with Austria and Hungary being important focal points in Central Europe and Germany and Benelux being focal points in NWE. Gazprom has commercial interests in both storage markets, mostly via Wingas. It is expected that Gazprom will develop more storage capacity in Europe.\(^{208}\)

**Sales strategy in Europe**

Having dealt with the volumes, more attention can be paid here to the actual Russian sales strategy in Europe in terms of long- versus short-term sales and vertical integration (i.e., business models). Gazprom’s export subsidiary ‘Gazprom Export’ is responsible for Gazprom’s exports. Based on Gazprom’s current long-term contractual agreements to Europe the export

\(^{206}\) Also see Chapter 10 in Smeenk [2010]. After the completion of the Nord and South Stream, if Gazprom were to decide to use Ukrainian transit route as a last resort, transit through Ukraine could fall to 0-16 bcm/y. However, storage in Ukraine is expected to remain important for Russia [Mitrova et al. 2009; own estimates].

\(^{207}\) In exchange for a 9 percent stake of Dutch Gasunie in the Nord Stream pipeline.

\(^{208}\) Storage is an essential tool in the gas value chain for handling (seasonal) variations in consumption. Demand is particularly high during the winters, while storage can be used during summers to pick up the stock in demand. Storage can come in the form of LNG storage tanks, ‘linepacking’ (storage in the pipeline itself), in underground caverns and in depleted gas fields or aquifers. In late 2008, Gazprom signed an MoU with Taqa to “pursue a partnership to jointly develop the Bergermeer gas storage facility” in the Netherlands. In addition, it will provide cushion gas to the Bergermeer gas storage project in the Netherlands (cushion gas refers to the gas injected into the underground storage facility to bring it up to operating pressure). This is an interesting development since this would constitute an important storage joint venture with another NEF in Northwestern Europe [Platts LNG Daily 2008].
volumes are about 180-200 bcm/y in 2015 (minimum and maximum deliveries respectively), an increase of 10-20 bcm/y from 2008. Most of these current, additional contracts are related to the construction of the Nord Stream pipeline [Stern 2009b], also refer to Case study 3 in Chapter 9. In Europe, Gazprom is currently renegotiating supply contracts (e.g., the long-term contract with E.ON Ruhrgas) such that minimum off-take obligations were lowered.

1) **Traditional long-term take-or-pay contracts:** Gazprom has historically sold gas to European consumers at their respective borders using netback pricing (linked to oil prices) in long-term take-or-pay gas contracts (with a duration of 20-30 years) with European mid-streamers (see also Part II in Smeenk [2010]) [Stern 2009b]. Many of Gazprom’s contractual commitments have been signed in the 1980s and 1990s, some of which will continue well into the 2010s. Gazprom signed new long-term agreements with a number of countries in 2005-2007.\(^2\)

2) **Direct sales: Cooperation and (vertical) asset swap:** As a result of liberalisation in Europe, an effort can be seen on Gazprom’s part of to sell its gas further downstream.\(^2\) As was mentioned above, Gazprom’s downstream activities in Europe started through the creation of a joint venture with BASF/Wintershall (Wingas). The amount of gas sales of Wingas has increased significantly: from 3.4 bcm in 1995 to 27.4 bcm in 2008 (an average annual growth of more than 17 percent) [Wingas 2006; Wingas 2008]. Other joint ventures have been formed, for example, with Italian (ENI) and French (Gaz de France) companies, in order to sell gas directly in these markets [Zhiznin 2007]. In most of the cases, joint operation in gas storages and transport routes to and within Europe (see above) and vertical asset-swaps are part of this business model when it comes to cooperation with mid-streamers. Through vertical swaps, Gazprom has gained direct access to European markets by cooperating with European mid-streamers. Two cases stand out here: Gazprom’s swaps with partners in Germany centred on the Nord Stream pipeline and Gazprom’s cooperation with *Ente Nazionale Idrocarburi* (ENI) from Italy centred on the Blue and South Stream pipeline. In both cases, Russian gas ends up on the German and Italian markets, ownership stakes are exchanged across the chain (also in Russia’s upstream sector) and the parties involved share the profits.\(^2\) In addition to this model of cooperation, other busi-
ness models of selling gas directly to European customers are: (1) wholly-owned greenfield operations or (2) M&As.

3) Direct sales: Greenfields: In one of the first steps of taking a foreign position outside Russia, Gazprom set up the wholly-owned Gazprom Marketing and Trading (GMT)\(^\text{212}\) in 1999. The focus of GMT is to optimise the usage of its capacities on the Interconnector pipeline as well as on leasing and natural gas trade, involving spot–based sales and non-Russian gas. It is designed to focus on its own trading activities in NWE on the NBP, Zeerugge, TTF, and PEG hubs. GMT sells gas to end consumers through subsidiary (retail) companies in the UK and France [Gazprom 2008b]. According to GMT [2009], GMT’s gas sales increased from 1.2 bcm in 2003, to 4.1 bcm in 2005 and 25.1 bcm in 2008.

4) Direct sales: Acquisitions: Gazprom is attempting to secure and maintain market share by buying equity in power and industrial enterprises, which are large gas users. This M&A strategy is mostly occurring in mature markets, while greenfields are likely to be explored in growth markets [De Jong 1989]. Due to Gazprom’s high market capitalisation a merger with a European mid- and downstream player seems not applicable (if desirable, only with IEFs, such as BP or Royal Dutch Shell). Most of the past and current acquisitions are occurring in Russia and in Central and Eastern Europe, also in order to control its transit pipeline network. Gazprom is increasingly bidding for (retail) assets in Western Europe as well, for example in the UK [AGC 2007a]. In these markets, Gazprom is exploring both a strategy of horizontal and diagonal (e.g., the power and/or the oil sectors) integration.

From the schedule mentioned above, one can discern that Gazprom combines a long-term sales strategy with a short-term, optimisation-based one [CIEP 2008]. A possible gap may provide room for volumes through the renewal of potential long-term contracts and any volumes traded above that level can be traded on a short-term basis, either in the form of shorter-term contracts or on spot markets at hubs such as NBP, TTF and/or Baumgarten.\(^\text{214}\) In a seller’s market, as and when Gazprom increases its share on European hubs, Gazprom could push

\(\text{oil interest in Libya. The two partners will also take up a 50-50 percent share in Wingas Europe, a venture designed to market Russian gas in Europe at large, outside Germany.}\)

\(^{212}\) Gazprom M&T Ltd is a 100 percent subsidiary of ZMB GmbH, which is a 100 percent subsidiary of Gazprom Germany GmbH. Gazprom Germany is 100 percent owned by OOO Gazprom export, which is a 100 percent subsidiary of OAO Gazprom. The headquarters of Gazprom M&T is based in London. Other 100 percent subsidiaries of Gazprom M&T are Gazprom M&T France SAS in Paris and Gazprom M&T USA, Inc in Houston [Gazprom Marketing and Trading 2009].

\(^{213}\) Görg argues that acquisitions are more likely to take place in Cournot-type markets, except for situations involving relatively high adaptation costs. Under such conditions, a greenfield strategy seems more desirable [Müller 2001].

\(^{214}\) Gazprom has acquired a 50 percent stake of the Baumgarten hub in mid 2007. It co-owns the hub with the Austrian gas company [AGC 2007b]. The hub is the end point of Gazprom’s planned and proposed South Stream pipeline and is located near some of Austria’s main distribution pipelines. It also possesses storage facilities with a combined capacity of 2.1 bcm.
these prices upwards as it increasingly becomes a marginal supplier in shorter-term European markets [Komduur 2007].

**Far abroad: export to the Far East markets**

Russia aims to develop, export and integrate its eastern gas resources with those in western Siberia by means of extensive greenfield investments, which is part of its role as an 'inner integrator'. The Far East also encompasses northeastern China (Manchuria) and Japan as well as the Koreas. According to Stern and Bradshaw [2008], the gas market in East Siberia and the Far East is expected to grow to 27 bcm in 2020 and 32 bcm in 2030, which could rise to 41 and 46 bcm, respectively (when account is taken of the rising demand of gas-processing industries). In the mean time, pipeline gas exports to China and Korea could reach 25-50 bcm by 2020, and LNG exports to the Asia-Pacific region could reach 21 bcm by 2020 and 28 bcm by 2030, which would imply a doubling of Sakhalin 2’s 12.8 bcm/y LNG export capacity. The vast majority for Russian domestic consumption and exports is expected to be produced at Yakutia and Sakhalin, while Irkutsk and Krasnoyarsk will themselves play a marginal role [Stern and Bradshaw 2008]. From a Russia’s point of view, pipeline exports to the Far East are part of the regional Russian gasification strategy. Gazprom’s drive to integrate reserves is expected to be a major policy priority for the period 2010-2020 in a massive greenfield-based drive to optimise Russia’s hitherto untouched eastern resources from Western Siberia (Yamal and Shtokman), to Siberia (with Kovylkta as the centrepiece) and the Far East (where Sakhalin forms the main reserve base).

Indeed, Gazprom’s internationalisation is based on three rationales: (1) attempting to vertically integrate into Europe’s downstream gas market; (2) globalisation of its gas exports to markets other than Europe; while (3) diversifying its reserve base [Locatelli 2008]. Gazprom has at its disposal several options for diversification: ‘going east’ as far as a regional initiative is concerned within Russia itself (gasification) and the accompanying export development to China, in order to add a third export market to Gazprom’s portfolio. However, it is LNG that potentially offers Gazprom the means of becoming a more (flexible) global player. The 2003 ‘Russian Energy Strategy’ placed significant emphasis on the development of Far Eastern gas resources, with the possibility of expanding production up to 106 bcm/y by 2020. During the same year, it is stated that the region will become accountable for 15 percent of total Russian gas exports [Stern and Bradshaw 2008].

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[215] For a detailed overview of developments and plans concerning Russia’s Eastern Siberian and Far Eastern resources, refer to [Stern and Bradshaw 2008].
Russian volumes to China

On the pipeline side, China has pursued a gas import and pipeline construction deal with Turkmenistan as well as Kazakhstan and this has a major impact on potential volumes from and deals with Russia, which would have to compete with Central Asian volumes. Indeed, with a Chinese choice for Central Asian gas instead of Russian gas through the Altai pipeline (for China’s West-East pipeline) from Western Siberia seems to have improved China’s bargaining position vis-à-vis Russia and have diminished the prospects for the Russian Altai pipeline (30 bcm/y when completed) [Stern and Bradshaw 2008]. If Russia’s Far East projects will be realised, the Kovylkta field is the most obvious choice for forming the basis for Russia’s far eastern export route [Stern and Bradshaw 2008]. In addition to the Altai pipeline from Eastern Siberia to China’s Xinjiang province, plans have been drawn up for two pipelines to enter China’s Manchuria province from Russia’s Far East, fed by Sakhalin I and surrounding resources.

A memorandum of understanding was signed between Gazprom and China National Petroleum Corporation (CNPC) at the meeting of the Chinese and Russian presidents in Beijing, in March 2006, regarding two gas pipeline projects: one from Western Siberia and the other from gas fields further east with a projected 68 bcm/y worth of Russian gas to be exported to China in 2020 [WGI 2006b]. A renewed understanding was reached in October 2009 on the supply of 70 bcm, starting in 2014-15, with pricing issues yet to be resolved [WGI 2009h] (although China accepted market prices on gas from Australia). Gazprom is already planning to start with construction of the Yakutia-Khabarovsk-Vladivostok, in operation by 2012 at the earliest [WGI 2008a].

One of these pipelines is in fact the Yakutia-Khabarovsk-Vladivostok pipeline, linking Sakhalin to Russia’s Far East, planned to form the backbone of Russia’s far eastern gas supply network in the region (for exports to China and South Korea). The other pipeline branches off from the Chayandinskoye-Khabarovsk pipeline (from eastern Siberia to the Far East) and is to enter China near the Russian town of Blagoveshchensk. Ultimately, this entire network is planned to be connected to existing infrastructure in eastern Siberia as well as planned infrastructure in that region. Finally, this will be interconnected with the network in West Siberia (and Urengoy) from which the Altai pipeline is to branch off. It is questionable however if, from a commercial logic, it is necessary to build all these interconnections within Russia.

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China has completed the Turkmenistan-China pipeline stretching from eastern Turkmenistan to Xinjiang Province, with a capacity of some 30 bcm/y.
South Korea

Russia agreed on a supply contract with South Korea at a government level in September/October of 2008, with the formal signing of the agreement is planned in 2010. South Korea would be supplied through the pipeline from Yakutsk and Sakhalin from 2015 onwards with 10 bcm/y. This represents the equivalent of 30 percent of South Korea’s annual LNG consumption. South Korea is the biggest LNG importer after Japan and gas is good for 13 percent of its primary energy mix. Russian pipeline supplies appear to be in favour with the South Korean government, these volumes seen as a reliable complementary source of gas with respect to a LNG market.

Far abroad: export to different regional markets by LNG

The LNG trade is, in the coming decade and beyond, likely to reposition Gazprom from being a regional player (in either Europe and/or Asia), to a more global one. Only Sakhalin II now provides Gazprom with the opportunity to sell LNG to the Pacific Basin, which is seen by Gazprom as part of a global strategy [Stern and Bradshaw 2008]. As far as proper Russian LNG is concerned, there are three main areas of attention: Sakhalin II for the short-term and Sakhalin III and IV, Shtokman and Yamal for the longer-term. The exchange of technology between Gazprom and LNG-oriented players (such as Royal Dutch Shell) takes place in the Sakhalin II project, and it could be intensified along the value chain on the whole of Sakhalin island. This may involve further integration, for example also, with the Sakhalin I project, led by ExxonMobil.

With the apparent onset of climate change and, specifically, global warming, in the long-term, Murmansk and Yamal LNG may increasingly have a global reach with the melting of the ice in the Arctic Ocean giving way to shorter and thus less costly routes to both East and West. Then, both locations will be within an economically acceptable distance of both the Atlantic and Pacific basins. The distance between Russia’s north Siberian liquefaction areas and US and Asian markets will be almost equal and will give Gazprom thus favourable arbitrage possibilities (as Qatar already does today).

6.2.5 Uncertainties related to Russia’s merit order

There are many uncertainties with respect to the development of a new merit order for Russia (and Gazprom). First, there are uncertainties concerning the level of domestic demand in Russia. The availability of gas from existing sources of production may increase due to the rise in domestic gas price levels, energy conservation and reducing dependency on gas fired power

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217 Gazprom’s export chief, Alexander Medvedev, has said that “joining the Sakhalin II project provides a powerful impetus for accomplishing a large-scale project in the energy supply sector to Asia Pacific countries and North America. It will stimulate implementing a stage-by-stage entering strategy on the world LNG market” [Financial Times 2007].

218 Royal Dutch Shell was invited in mid-2009 to help develop Sakhalin III and IV.
generation. The growing Russian economy may on balance require more gas for its domestic market, although this has become more uncertain due to the economic instability since the autumn of 2008. From a government perspective, supply to this market will be given priority over exports. Second, the levels of gas imports from Central Asia to Russia and gas production of independent gas companies are uncertain. There is increasing competition from Asia and Europe for Central Asian gas, which makes it not self-evident that the gas flows will go to Russia. Uncertain government policy towards independent and foreign gas producers within Russia makes the production from these producers also more volatile. Third, the present uncertainty about future gas demand in Europe and Asia, stimulated also by the recent economic instability, may delay new commitments on contractual agreements and therefore new investments. There are also price uncertainties, especially in China, which negatively influence Gazprom’s investment programmes. Government policy measures and regulatory affairs (in Europe) will also increase uncertainty with respect of new investments for Gazprom [CIEP 2008].

All these uncertainties, combined with the current economic crisis which has a large impact on Gazprom (as a result of exposure to short-term liabilities), will influence new investments along the Russian gas value chain as far as investment decisions currently on the table are concerned. In the upstream for example the pace of additional gas production from new gas fields (mainly Zapolyarnoye, Yuzhno-Russkoye, Shtokman and Yamal Peninsula) in order to replace declining production from the four giant gas fields (Medvezhye, Yamburg, Urengoy, and Orenburg) and increase production for the export market. In the midstream, green- and brownfield projects in order to allocate new supplies to growth markets, such as the South Stream, could be suspended. Also new Russian LNG projects could be delayed due to the above-mentioned uncertainties. In the downstream, new greenfield investments for direct sales (in corporation with foreign companies) may be deferred [CIEP 2008].

6.3 Gas strategies of former Soviet republics in the Caspian region
As was explained in Chapter 3, the break-up of the Soviet Union in the early 1990s has changed the institutional make-up of economic and political relations between the former Soviet-states. Russia realised over the course of the 2000s that the region would play an important geo-economic role in its gas balance. Given the geographical circumstances and Russia’s natural monopsony through the lack of alternative export infrastructures from the region, the three Central Asian gas exporters have had, up to recently, little choice but to sell their gas

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219 The position vis-à-vis foreign participation in Russia’s upstream gas sector could positively be changed as a result of the economic crisis of 2008-2009.

220 The physical inter-linkage between Russia’s current UGTS and the Central Asian states dates back to the days of the Soviet Union.
to Russia. Now that Turkmenistan’s export route to China has been opened, this situation has changed significantly for all three of these countries.

During the 1990s, the Caspian Sea countries formulated their own strategies, which were not necessarily in line with Russian interests, pursuing alternative export routes for gas to Asia and Europe to lessen their dependence on Russia. Upon the collapse of the Soviet Union, and through the 1990s, the US and other Western energy firms became enticed by the region’s energy potential, forging ahead with exploration contracts in Azerbaijan and set to play a new part in negotiations in the region, in Kazakhstan as well [CIEP 2004]. The US and Western governments in general have supported IEF access to Caspian Sea gas reserves during the ‘new great game’ and do so today as well, primarily in Kazakhstan, Azerbaijan and Turkmenistan.

However, the success of a so-called multi-vector approach, in which these countries attempted to diversify their ties extensively beyond the region, was ultimately rather limited. Internal, structural socio-economic problems, such as an ill-functioning legal system, led to investment delays. In the construction of alternative export pipeline projects, the Caspian Sea countries experienced strategic competition between governments and NEFs and IEFs. Combined with low oil and gas prices, intense competition for new possible off-take areas, issues of the legal status of the Caspian Sea[222] and transit risks, which placed pressure on profitability, only a limited number of projects was realised. During the 1990s, the Caspian Sea region became dependent to a large extent on the transport of their exports through Russia. During the second half of the 1990s, with the rise of Russia’s domestic gas demand (see Part II in Smeenk [2010]), Russia began to show more interest for Central Asian gas as volumes from the region correspondingly gained in (geo-)strategic significance, as discussed in Chapter 3.

Collectively as a region, Central Asia and Azerbaijan hold almost 7 percent of total world’s gas reserves (12.54 tcm) [BP 2009]. The combined flows from the three Central Asian producers feed into the Russian UGTS and are re-exported mostly to CIS markets such as the Ukraine, totalling 77 bcm in 2007 [IEA 2008b]. The ‘natural’ monopsony hereby afforded to Russia

[221] For an overview of the problematic development of a new legal status of the Caspian Sea, see for example [Zhiznin 2007].
[222] Confirmation of recent onshore gas finds in Turkmenistan (e.g., the Yolotan gas field) is likely to intensify competition for exploration and development rights in Turkmenistan and a succession of governmental delegations have received varying degrees of encouragement on the Turkmen side [IEA 2009b].
[223] Gazprom itself underscores this aspect explicitly: “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 Seas. All these areas have exceptionally challenging climactic 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” [Gazprom 2008a, p. 61].
[224] In addition, an international legal framework for energy cooperation between Russia and Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan is being developed, in which the Eurasian Gas Alliance could be an important platform for the gas sector (besides Russia’s bilateral agreements with these countries) [Zhiznin 2007].
is a major advantage today for Moscow in its dealings with the sovereign Central Asian suppliers, providing it with some bargaining power over them. Conversely, they persistently seek alternative export options. This game involves Russia, China as well as a number of other regional and extra-regional players (Iran, Afghanistan, Pakistan and India) and external powers, such as Europe and the US [Amineh 2003]. As a result of the 2008-2009 economic crisis and the Russian-Ukrainian gas conflict(s), the position of and competition for new gas exports from the Caspian region may change.

Currently, Turkmenistan is the biggest reserve holder, producer and exporter of gas in the Caspian region. Other countries produce a relatively small amount of gas (Azerbaijan and Kazakhstan) or consume their gas largely domestically (Uzbekistan). The bulk of Caspian exports goes to Russia. Turkmenistan is exporting some of its gas to Iran, whereas Azerbaijan is supplying gas directly to the Turkish market (combined with minor exports to Iran and Georgia), see also Figure 6.9 [IEA 2008b].

**Figure 6.9** Natural gas balances of Caspian countries in 2007

*Figures of Kazakhstan are estimates and are from KazMuniaGaz. Other sources (Gazprom and Kazakhstan Statistical Agency) estimate higher volumes. Totals may not add up due to rounding.

Source: IEA [2008b]; IEA [2008].
6.3.1 Azerbaijan

Azerbaijan has one of the longest traditions as a gas and oil producer [Bowden 2009]. In a relatively short amount of time, after the 1999 discovery of the offshore Shah Deniz gas field (450 bcm) in the Azeri shelf of the Caspian Sea, Azerbaijan changed its position from a net-importer to a net-exporter in 2007 [CIEP 2008]. During the 1990s, the Bakhar gas fields were responsible for 40 percent of the Azeri total production. Other vital fields are Nikhichevan, Gunashli, Iman and Asheron. Most of these fields, except for Shah Deniz and the Azeri-Chirag-Gunashli (ACG) associated gas fields, are operated by the State Oil Company of Azerbaijan Republic (SOCAR), which has close ties with the Azeri government [Bowden 2009; Amineh 2003]. In 2008, Total signed an memorandum of understanding with Azerbaijan, which covers the offshore Apsheron block [Bowden 2009].

In 2008, Azerbaijan produced a total of 16.3 bcm (10.8 bcm in 2007), including associated gas production from the Azeri-Chirag-Guneshli oil field (2.4 bcm in 2007) and Shah Deniz (3.1 bcm in 2007) [Bowden 2009; IEA 2008d], while it consumes 11 bcm [IEA 2009a]. In 2008, Azerbaijan had an energy mix of which 68 percent was satisfied by gas, 27 percent by oil and 4 percent by hydro-electricity [BP 2009]. Some of the gas production from phase I of the Shah Deniz field (8.6 bcm/y) is sold within Azerbaijan (1.5 bcm/y), the remainder is already fully contracted to Georgia (0.8 bcm/y) and Turkey (up to a maximum of 6.3 bcm/y), with small volumes re-exported from Turkey to Greece (up to a maximum of 0.75 bcm/y). Azerbaijan exports its gas through the South Caucasus Pipeline (SCP), which could eventually be extended to 20 bcm/y [Bowden 2009; IEA 2008d]. Gas is sold on a joint basis via a gas aggregator (the Azerbaijan Gas Supply Company) [Bowden 2009].

Azerbaijan has the potential to expand its gas production via the development of Shah Deniz Phase II and additional production from SOCAR’s fields. From 2012 onwards, phase II could bring around or above 12-15 bcm/y of additional gas to the market, of which 9-12 bcm/y could be available for export [IEA 2008c]. Europe (including Turkey), Iran, Russia and potentially Georgia have to compete with one another and the domestic market for these supplies (expected to increase to 13-15 bcm in 2015) [Bowden 2009]. Iran may possibly increase its Azeri imports substantially to 12 bcm in 2012, whereas Russia offered to buy Shah Deniz

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25 For a recent in-depth analysis on Azeri (future) gas sector, see for example Bowden [2009].
26 StatoilHydro (25.5 percent), SOCAR (10 percent), Total S.A. (10 percent), LukAgip, a joint company of ENI and LUKoil (10 percent), Oil Industries Engineering & Construction (10 percent), and Turkish Petroleum Overseas Company Limited (9 percent) are shareholders in the Shah Deniz consortium. Currently, BP is the operator.
27 The Azerbaijan International Operating Company (AIOC), an international consortium, operates these fields through a 30-year PSA signed in 1994 [Bowden 2009].
phase II gas at ‘European-level’ prices. The Azeri gas to Russia could be shipped via a Soviet-era pipeline (design capacity is 13 bcm/y, although real operating capacity is plausible lower), which had to be reversed [IEA 2008d]. The Russian desire for Azeri gas makes sense from a strategic perspective, because it could moderate Azeri competition towards Turkey and other SSEE markets. In addition, Gazprom could use Azeri gas on a commercial basis for relaying it to the Blue or South Stream pipelines (Case study 2 in Chapter 9). Although Azerbaijan had a westward looking policy and there are Western companies involved in Azeri upstream developments, Russian and Iranian proposals provide additional leverage with regard to European transit and off-take countries and companies.

6.3.2 Turkmenistan

Until late 2006, the ‘neo-Stalinist’, flamboyant dictator Saparmurat Niyazov practically decided on all matters political and economic in Turkmenistan. Since his death in 2006, Berdymukhamedov has replaced him as the country’s leader and officially controls the process of decision-making over the gas and oil sector [Zhukov 2009a]. Turkmenistan is still seen by Russia as part of its exclusive sphere of influence [Olcott 2006]. Speculations on the part of some observers that the country’s reserve base may be larger than officially held (one which has lingered ever since the fall of the Soviet Union) appeared vindicated with the recent discovery of new gas fields. Official sources in Turkmenistan put the country’s reserve base at 22.4 tcm [Zhukov 2009a], far more than the recently updated 7.94 tcm reported in BP [2009], up from 2.43 tcm in 2007. The most sizeable and truly large deposit discovered in 2008 includes the South-Yolotan-Osman gas field, estimated to contain between 4 tcm and 14 tcm.

Turkmenistan is the region’s largest gas producer, producing 70.8 bcm in 2008, 2.2 percent of the world’s total, and thus also the most important Central Asian gas supplier to prospective importing countries [IEA 2009a]. The Dauletbad and the Yashlar fields are Turkmenistan’s major gas-producing areas, with the former forming the backbone of Turkmenistan’s gas production. Alongside the above-ground risks affecting gas production in Turkmenistan, there are likely to be significant challenges with the next generation of gas production from these new

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228 In June 2009, Gazprom already signed an agreement with SOCAR for the annual purchase of 500 mcm from SOCAR’s own gas fields [Eurasia Insight 2009b]. In September 2009, Azerbaijan agreed to export gas to Iran 5 bcm/y. The gas is destined for consumption in Northern Iran.

229 For a recent in-depth analysis on Turkmen (future) gas sector, see for example Zhukov [2009].

230 The South Yolotan and Osman fields were discovered in 2006 and early 2007, respectively, and are located close to the Yashlar field, estimated to hold 0.7 tcm. The best estimate for the South-Yolotan-Osman field is 6 tcm, which is now considered to be a single structure, which would make it one of the biggest fields in the world, the fifth or fourth largest (c.f., North Field and South Pars) [PIGR 2009b]. Other discoveries include for example a large gas condensate field at the South Gutlyyak field [PIGR 2008b]. Another recent find includes a field near Gurrukobil-Garabil, near the Dauletbad field [IEA 2009b]. Its oil reserves (0.6 billion bbls) and production (205,000 barrels per day) are rather small when one compares it with Kazakhstan, the leading oil producer of the region [BP 2009].
Two 100 percent government-owned companies, Turkmenneft and Turkmengaz, are responsible for the Turkmen oil and gas sector. The Turkmen gas sector is partly closed to foreign investors. In principal, onshore projects are exclusively allocated to the state companies. Two small projects are subjected to foreign partners from the US, Turkey and the UK, some of the partners operate through service contracts [Zhukov 2009a]. An exception was made for Chinese CNPC, which has obtained drilling exploration wells at the South-Yolotan field since 2007 and already has a PSA in the Amu Darya basin [PIGR 2008g]. Turkmenistan is also looking for possibilities in terms of exports and swaps with Iran. Other foreign interests in onshore development are limited to service contracts, although offshore fields are currently more open for foreign investors (e.g., Petronas, Dragon Oil, Wintershall, Maersk Oil and ONGS Mittal Energy. Some other projects are under negotiation).

In 2008, Turkmenistan had an energy mix of which 76 percent was satisfied by gas and 24 percent by oil [BP 2009]. Turkmenistan’s total as well as per capita consumption is high, 15 bcm in 2007, because gas is supplied free of charge or largely subsidised. Its current exports are also significant (54.3 bcm in 2007). The Turkmen government had the intention to raise production to 100 bcm in 2010, 160 bcm in 2015, 190 bcm in 2020, and 250 bcm in 2030, and indeed Turkmenistan has much potential [IEA 2008c]. However, the IEA [2008] estimates that Turkmenistan’s production cannot exceed 100 bcm/y in the mid-term. Zhukov [2009] projects a minimum production of 105 bcm in 2015 from the onshore fields and a maximum of 126.9 bcm. The projection of the offshore production on the Caspian shelf could increase from 3.5 bcm in 2008 to 14 bcm in 2015 [Zhukov 2009a]. With an expected growth of domestic consumption from 18 bcm in 2007 to 20-30 bcm/y in the mid-term [IEA 2008c], largely due to the development of gas-based industry in Turkmenistan, a significant amount of gas will remain available for exports.

As a result of the importance of Central Asian gas in Gazprom’s supply balance, Russia secures additional volumes by means of new contractual agreements. Thus, in April 2003, Putin and

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231 These challenges will likely come in the form of greater long-run extraction costs, mostly because of the depth of new reserves, high pressure and high temperature as well as the fact that the gas is mostly sour [IEA 2009b].
232 However, the Turkmen government has announced that it will retain its (quasi-)monopoly over onshore deposits [Zhukov 2009b].
233 Potentially, Gazprom, Turkmengaz and NIOC may find an arrangement in which Gazprom supplies northern Iran with small gas volumes from Turkmenistan under a swap agreement [WGI 2009i].
234 See also Table 9.6 in Zhukov [2009, p. 283] for an overview of the involvement of foreign companies in the Turkmen gas and oil fields. Currently, RWE is negotiating on development rights for an offshore block and underscores Turkmenistan’s growing and apparent readiness to export gas to Europe. If hydrocarbon reserves are found in the area, RWE might gain a license for production during 25 years [WGI 2009i].
235 The South Yolotan-Osman field alone could begin phased production at 10 bcm and move gradually to 70 bcm [PIGR 2009b].
236 Because of the use of other methodology, Zhukov [2009a] estimates are much lower, namely 14-16.9 bcm in 2015. In order to meet its export commitments, gas production will need to increase to 119-141 bcm by 2015 [Zhukov 2009a].
Niyazov signed a 25-year agreement on the long-term cooperation in the gas industry between Gazprom and Turkmengaz, which was accompanied by a long-term gas supply contract between both parties (70-80 bcm from 2009 onwards until 2028) [WGI 2007b; Gazprom 2008; Zhukov 2009a]. In the face of Turkmen requests for price increases and in an effort to maintain its position in the region, Gazprom gradually increased the price paid for Turkmen gas. From $60/mcm in 2006 (which was still a 50-50 barter/cash deal) [IEA 2008c], the price for Turkmen gas rose from $130/mmc to $150/mmc in 2008 and from $250/mmc to $270/mmc in 2009 [Kommersant 2008a], moving in principle to ‘European’ market-based netback prices [IEA 2009b].

Russia has also offered to aid in improving the Soviet-era infrastructure that carriers Central Asian gas to Russia in a bid to tie in Turkmenistan and facilitate further flows. The system runs from Turkmenistan and Uzbekistan via Kazakhstan to Alexandrov Gai in Russia, to be boosted in capacity to 90 bcm/y by 2009-2010 (current capacity is estimated at 45-55 bcm/y). In order to boost the transport of additional gas production from West Turkmen gas fields (and Kazakh fields) to Russia, the associated countries signed an agreement to revamp a littoral Caspian Sea pipeline from 10 bcm/y to 30 bcm/y by 2012 in mid- and late 2007. In April 2009, Russia decided to stop buying Turkmen gas, following an explosion in the Central Asia Centre pipeline [WGI 2009j]. Russia and Turkmenistan are still renegotiating lower volume and price terms in their contracts. For now, there is no official clarity what progress will be made further in this matter.

From 1997 onwards until 2024, Iran has been importing gas at a minimum of 4 bcm and a maximum of 8 bcm/y via the Korpezhe-Kurt pipeline from Turkmenistan to Iran [Olcott 2006; Zhukov 2009a]. Although historically speaking there have been price disputes between Turkmenistan and Iran, in January 2010 both countries inaugurated a new pipeline that has the potential to double flows to Iran to 20 bcm/y [WGI 2010f]. Exports to China through a new pipeline from gas fields in southeast Turkmenistan are has started in December 2009, which should reach to full load factor (at least 30 bcm/y) by 2012. In China the pipeline will

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237 Gazprom’s earlier agreement with Turkmenistan included prices at the Kazakh border linked to the amount paid by Gazprom’s long-term European customers [WGI 2007b].
238 Gazprom plans to modernise and upgrade its Soviet-era Central Asia-Centre (CAC) pipeline system. The CAC pipeline system consists of four main pipelines (e.g., SATS 1, 2, 4, and 5), and was build in phases during the 1960s, 1970s and 1980s.
239 The objective is to revamp the existing Soviet SATS 3 branch of the CAC, a littoral section known as the “Pricaspiskiye” pipeline, bringing the pipeline’s capacity to 20 bcm/y from 10 bcm/y, by 2012. This pipeline is linked to the CAC pipeline system in Kazakhstan, with volumes supplied consisting of 10 bcm/y from Turkmenistan and Kazakhstan, respectively. In 2008, Gazprom announced that this pipeline could be expanded to 30 bcm/y. Turkmenengaz, Kazmuniagaz and Gazprom will upgrade the pipeline [IEA 2008d]. By mid-2008, Turkmenistan suggested that the line could be expanded even further to 40 bcm/y [WGI 2009i].
240 In August 2008, Turkmenistan agreed with China in principle to increase its sales volume to 40 bcm/y [IEA 2009b].
be connected with the West-East pipeline, which stretches from Xinjiang province. China’s regulatory landscape, combined with increasing domestic production and market uncertainties, may hinder an additional call on import gas [IEA 2008c]. After the fall of the Taliban regime in 2001, the Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline has been brought back under discussion, but its realisation is still very uncertain and is discussed more in a geopolitical rather than a practical framework (the pipeline has a planned capacity of 30 bcm/y) [Zhukov 2009a; IEA 2008c]. Indeed, Chapter 11 deals with the geo-strategic dimension of this pipeline.

In early 2008, the Turkmen president promised to commit 10 bcm/y worth of gas to Europe by 2009, though no commercial arrangements or agreements were made [WGI 2008e]. Moreover, how this gas will be transported to Europe remains uncertain. The TCGP (see Case study 1, Chapter 9) is still merely a speculative project, which is subject to uncertainty over permits in offshore transport through the Caspian Sea and possible political transit risks in Georgia [CIEP 2008; Zhukov 2009a]. Europe and the US are also investigating different measures to import Turkmen gas (see case studies 1 and 2 in Chapter 9). When adding up the volumes from Turkmen export agreements under discussion, the agreed annual volume promised, is boosted to 118 bcm/y in total (excluding the speculative TAPI pipeline and exports to Europe). In the most favourable scenario (which is uncertain), some 10-20 bcm/y could be available by 2015 for additional export commitments and, perhaps, even more export possibilities in the long run.

6.3.3 Kazakhstan

Kazakhstan, like Turkmenistan, is ruled by an ex-Soviet regime headed by Nazerbayev, although the regime is much less totalitarian. The regime was relatively open to foreign investment and international energy firms in its oil and gas sector. However, this has changed in recent years. In 2002, Kazmunaigaz became the Kazakh NEF and in 2004 new legislation was introduced that gave Kazmunaigaz a minimum stake of 50 percent in new PSAs [Yenikeyeff

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241 The pipeline would run from the Dauletbad gas fields in southeast Turkmenistan, either via a southern route through Heart and Kandahar in Afghanistan and Pakistan to India, or via a northern route. However, on this issue, Russia’s Gazprom maintains that the gas being proposed to be transmitted through TAPI pipeline is in fact owned by Gazprom through its agreements with Turkmenistan [Jalalzai 2003].

242 During the 1990s, American and other firms examined options to transit gas from Turkmenistan through Afghanistan to Pakistan and India, and attempts were made at the corporate and policy-making level in the US to win over Taliban-led Afghanistan to conclude a deal in this regard, which ultimately failed. After the September 11, 2001 attacks, a direct US presence in Afghanistan brought the prospect of the trans-Afghanistan pipeline closer to reality.

243 Currently, the EU, through its INOGATE programme, and the US Trade and Development Agency had and is financing (pre-)feasibility studies in exploring (non-)pipeline options via the Caspian Sea [IEA 2008d]. In addition, the EU floated the idea of consolidated a gas purchasing mechanism for gas east from the Caspian Sea (i.e., the Caspian Development Corporation, CDC) [IEA 2009b]. Therefore, in line with the TAPI, the TCGP project is still more discussed in a geopolitical framework [Zhukov 2009a].

244 For a recent in-depth analysis on Kazakh (future) gas sector, see for example Yenikeyeff [2009].
Kazakhstan’s ties with Russia are relatively close, but Kazakhstan is also opting for cooperation with foreign players.245

As far as oil reserves and production are concerned in 2008, Kazakhstan had reserves of 39 billion barrels (bbls) and produced 1.5 million barrels per day (mb/d) which was 1.8 percent of the world’s total. Kazakhstan is therefore clearly an important oil producer and exporter, the largest in the Caspian region. Conversely, the country has 1.82 tcm worth of gas reserves (1 percent of the world’s total) [BP 2009]. Kazakhstan is also a considerable producer: 25.9 bcm in 2008, according to IEA [2009b], although its upstream gas sector is relatively underdeveloped [CIEP 2008]. Most of the gas deposits are located in the west of the country, notably in associated gas fields such as Tengiz246 and Karachaganak.247 Kashagan is another important associated gas field being developed by foreign partners (with the associated gas being under high pressure).248 Other significant fields include, for example, Zhanazhol and Uritau. Much of the gas produced in Kazakhstan is either re-injected for oil lifting or is flared, but some of it is also exported to Russia for further processing. Russia and Kazakhstan established the Kazrosgaz joint venture (50 percent is owned by Gazprom and 50 percent by Kazmunaigas) in 2002.249

In 2008, Kazakhstan had an energy mix (64.7 Mtoe) in which coal enjoyed the largest share at 52 percent, followed by natural gas at 29 percent oil at 17 percent and hydropower at 3 percent [BP 2009]. Coal thus plays an important role in Kazakhstan’s domestic consumption, enabling it to export a large portion of its oil and some natural gas production. In 2007, it exported 5.5 bcm to Russia [IEA 2008c]. Annual gas production in Kazakhstan could increase to 40 bcm by 2015 and 50 bcm by 2030 [IEA 2008c]. Estimates are that the gas volumes for

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245 From 1997, Belgium’s Tractebel was responsible for Kazakh trunk pipelines via Intergaz Central Asia. But in 2000 Kaztransgaz took over the gas infrastructure [Yenikeyeff 2009].
246 Tengiz is developed under a PSA (Tengizchevroil) with Chevron, ExxonMobil, Kazmunaigas and the Russian-owned LukArco [Yenikeyeff 2009].
247 The deposit is being developed by Karachaganak Petroleum (KPO), an international consortium that includes British Gas, Chevron, ENI and Lukol. The Karachaganak field is actually a condensate field located onshore, containing an estimated 1.3 tcm worth of natural gas [US Department of Energy 2008]. In 2007-08, Tengizchevroil and KPO have been responsible for more than 70 percent of gas production in Kazakhstan [Yenikeyeff 2009].
248 The consortium operating the field is the Agip Kazakhstan North Caspian Operating Company (Agip KCO), which includes the following shareholders: Kazmunaigas; ExxonMobil; Royal Dutch Shell; Total; Eni; Conoco; Inpex [Yenikeyeff 2009].
249 This is centred on the giant Orenburg Gas Processing Plant (OGPP) complex in Russia (near the border with Kazakhstan) to market Kazakh gas internationally. In November 2005, Gazprom and Kazmunaigas’ transportation subsidiary, Intergas Central Asia also signed medium-term contracts dealing with the transportation of Russian and Central Asian gas through Kazakh territory from 2006 to 2010 [Gazprom 2006a, p. 61.] Both countries agreed to process 16 bcm/y from Karachaganak (to be processed at the OGPP) in mid-2007, to be used domestically in Kazakhstan and re-exported through Russia [Gazprom 2009b].
250 According to IEA [2008c], in 2007, Kazakhstan imported 3.2 bcm/y and exported 5.5 bcm to Gazprom. The 2007 Gazprom Annual Report mentions that Gazprom imported 8.5 bcm from Kazakhstan and exported 10 bcm to Kazakhstan.
251 The Kazakh government projects and production level of around 80 bcm by 2015 and 114 bcm by 2020 [Yenikeyeff 2009].
commercial use could reach between 30 and 40 bcm by 2020, against rising domestic demand of 18-20 bcm [IEA 2008c]. As a result, 10-22 bcm/y could be available for export by 2020, whereas Yenikeyeff [2009] estimates the availability of export at 19-20 bcm/y by 2015 (in the best case, probably 7-9 bcm/y higher when imports from Uzbekistan remains to be taken into account).

Of these volumes, Yenikeyeff [2009] projects that 15 bcm/y will be sold to Gazprom, which is in line with preliminary agreements. In August 2008, Chinese CNPC and Kazamunigaz agreed to build a gas pipeline (10 bcm/y), which will link to the Turkmen’s one. According to the IEA [2008c], Kazakh gas deliveries to China are expected to be rather small, although an integrated pipeline system could offer swap opportunities [Yenikeyeff 2009]. In the future, a small volume of gas might be transported directly to Europe via the TCGP. However, this is highly uncertain because of competition from potential export routes for gas to Russia and China, as in the Turkmen case.

6.3.4 Uzbekistan

Uzbekistan is also ruled by a former Soviet ruler, Karimov, and is the most reclusive and isolated of the four republics covered here. Uzbekistan has 1.58 tcm of gas reserves (0.9 percent of the world’s total) and is a significant gas producer, producing 67.4 bcm in 2008, (2.1 percent of the world’s total). Its production is consumed largely domestically (53.1 bcm in 2008) [IEA 2009a]. Uzbekistan is producing gas from approximately 50 gas fields, in which seven fields are responsible for more than 95 percent of the total production (which include Shurtan, Zevardy, Dengizkul’-Khauzak, Alan, Kokdumalak, Pamouk and Koultak fields) [Zhukov 2009b; Amineh 2003]. Uzbekistan’s energy mix in 2008 (52.2 Mtoe) relied for 84 percent on gas, 11 percent on oil, 3 percent on coal and 3 percent on hydropower [BP 2009]. Uzbekneftegaz is largely responsible for the country’s gas production (for about 95 percent). Some other foreign companies, such as Russia’s Gazprom and Lukoil and Zeromax joint ventures, operate in upstream (via joint ventures with Uzbekneftegaz). In order to boost its gas production, Uzbekistan has also signed new PSAs, primarily with Russian and Asian companies [Zhukov 2009b; IEA 2009c].

Uzbekistan exported 10.5 bcm to Russia in 2007 and other Central Asian countries (4.2 bcm in 2007)[IEA 2008b]. Uzbekistan is also responsible for part of the Turkmen transit to Russia.

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252 This route will run parallel to the already operational Kazakhstan-China oil pipeline. For an extensive overview of the politico-economic factors involved in China’s oil import diversification strategy, in which Kazakhstan plays a central role [Handke 2006].

253 This could change only if the Chinese project does not succeed and/or the amount of re-injections at Tengiz and Kashagan decrease [Yenikeyeff 2009].

254 For a recent in-depth analysis on Uzbek (future) gas sector, see for example Zhukov [2009b].

According to estimates, this situation will remain for the near future [Zhukov 2009b; CIEP 2008]. In 2002, Gazprom signed import contracts with Uzbekistan [Stern 2005]. Uzbekistan recently offered to sell Gazprom 16 bcm/y in 2009 and possibly double this amount in the future [WGI 2009]. The construction of the Turkmen and Kazakh pipeline to China will open up the possibility to start gas trade with China, although it will be difficult to increase its export level above 15-16 bcm/y by 2010 (and in the best case 20 bcm/y in 2015, probably temporary) as a result of the domestic consumption. A direct link to the European market via the TCGP is purely speculative (also see Chapter 11).

Figure 6.10 Export potential from the Caspian region (base case scenario)

When one combines all the export potential from the Caspian region, Turkmenistan could export a large amount of gas, followed by Azerbaijan as a result of its Shah Deniz field (see also Figure 6.10, which represents but one of many imaginable scenarios). However, Gazprom has already locked in most of the exports, while China and Iran have some import contracts as well. The remaining spare production capacity could be exported to different regions, including Europe and Pakistan and/or India. Currently, Azerbaijan is the only exporter of gas to OECD Europe (including Turkey, Switzerland and Norway), and could increase its exports to Europe.

**Notes**

"The situation will cardinally change only if a large gas deposit is found and rapidly brought on stream – but the probability of such development is low. Export supplies could also be increased at the expense of domestic consumption" [Zhukov 2009b, pp. 389 - 390].
The current economic crisis, combined with the Russian-Ukrainian gas disputes in 2005-06 and 2008-09, could have an impact on the interests to Caspian gas of the different stakeholders and therefore on the outlook for Caspian gas production and exports. From Russia’s perspective there are roughly two scenarios:

1) First, as a result of the declining economic activity and gas demand within Russia and other CIS (principally, Ukraine), the pressure on Russia’s supply portfolio, and therefore Caspian imports fell in the short run and this will remain for the medium term. The reduction of the call on Caspian imports might be encouraged by ongoing greenfield investments in Shтокman and possibly Yamal.

2) In a scenario involving the delay of new Russian (e.g., as a result of a lack in financial feasibility) combined with newly committed supplies (take-or-pay) to Europe, the importance of Caspian gas in Russia’s gas balance will persist. As a consequence of potentially declining economic activity in China, gas for power generation could be affected negatively, which may have an impact on additional gas import requirements from the Caspian region as well.

From a European view, the Russian-Ukrainian gas disputes accelerated the perceived need for greater imports from the Caspian Sea region in order to diversify away from Russia and Ukraine (in terms of both the origin of supplies and routes). However, current dampening European gas demand and imports may postpone the commitment of new gas supplies from outside Europe.

Regardless of external factors such as oil prices and macro-economic conditions, the Caspian Sea countries (especially Turkmenistan and Kazakhstan) are likely to continue playing Russia, China and Europe off against one another. For now, on-the-ground export route diversification is limited. Yet from in late 2009, Turkmenistan (as well as Kazakhstan and Uzbekistan) is no longer as reliant on export routes to Russia. As a result of Turkmenistan’s (as well as Kazakhstan’s and Uzbekistan’s) successful development of an alternative gas export route to China, the balance of bargaining power in the region will certainly change. In a similar manner, Azerbaijan may continue to play off Russia, Iran and European buyers as and when more of its gas becomes available.

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257 The gas demand within Russia could be not as much affected as a consequence of reducing government’s drive to increase regulated prices, rising prices could stimulate inflation, which may have a negative impact on the economic development.

258 This is the result mainly of the scheduled opening of a large-volume export route to China, in addition to existing smaller capacity link to Iran [IEA 2009b].
6.4 Iran

Section 6.4.1 is an overview of Iran’s gas reserves and current gas balance. Section 6.4.2 provides an impression of Iran’s gas sector in terms of revenues, institutionalisation, decision-making, and foreign participation. In Section 7.4.3, attention is paid to Iran’s domestic gas needs and strategy. Section 6.4.4 addresses Iran’s gas export ambitions by pipeline and LNG. Section 6.4.5 is an overview of Iran’s cooperation with other gas exporting countries. Iran’s gas relationship with Russia is covered in an additional section, Section 6.4.6, which is not included in other country overviews.

6.4.1 Gas reserves and current gas balance

Iran’s gas reserves clock in at 29.61 tcm, some 15.6 percent of the world’s total [BP 2009], with a reserves-to-production ration (R/P ratio) of well over 50 years. Iran produced 121 bcm in 2008, 3.8 percent of the world’s total [IEA 2008b]. As for oil reserves and production, Iran has 137.6 billion bbls worth of oil reserves (10.9 percent of the world’s total), produced 4.3 mb/d in 2008, with an R/P ratio 86.9 years and is a key member of OPEC. Iran’s natural gas reserves accounts for just over 50 percent of its fossil fuel reserves [Flower 2008b]. The largest concentration of reserves for Iran is located in its giant South Pars field. Geologically, the field is an extension of Qatar’s 25.5 tcm North Field. South Pars was first identified in 1988, and originally appraised at 3.62 tcm in the early 1990s.

Current estimates are that South Pars contains between 8 tcm and 14 tcm (some estimates go as high as 40 tcm) of natural gas, of which a large fraction will be recoverable [Flower 2008b]. Other important fields include North Pars (2.27 tcm), Kangan-Nar in the Persian Gulf Basin and Khangiran in the North-East basin. Iran’s gas reserves are based mainly on independent gas fields, gas caps and associated gas, produced together with oil [Ghorban 2006]. Thus a most favourable feature of Iran’s gas deposits is that around 62 percent are located in non-associated gas fields and have not been developed [US Department of Energy 2009b], meaning that Iran has vast potential for future gas development. The IEA estimates Iran could reach gas production of 139 bcm and 313 bcm by 2015 and 2030, respectively, a yearly rise of some 4.7 percent per annum [IEA 2008c]. Since 2000, the incremental production capacity at South Pars has been larger than that of the North Field in Qatar, with output

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260 As Ghorban notes: "Iran is producing around 8 percent of their combined gas production and could produce five times the current level, on a par with the US and Russia for over 40 years" [Ghorban 2006].

261 According to Flower, the North Field/South Pars gas reservoir could hold as much as a stunning amount of 40 tcm, close to 55 percent of total regional Persian Gulf supplies.

262 As is the case elsewhere, data on oil and gas reserves in Iran have to be taken with caution. For example, all gas fields, associated and un-associated, are put into one basket while their life expectancy is often ill-defined due to bad exploration methods: "Regarding the South Pars field, its best part is done," says Paul Graf, oil engineer and consultant. In his view, the remaining exploration might be of far inferior quality. Such uncertainties and the difficulties with the investment scheme and the available engineering in Iran confront investors with various problems [Kneisl 2006].
from phases 6 through 10 to reach 45 bcm. Production in Iran in general rose by 9 percent per year between 2000 and 2007. For a graphical overview of Iran’s gas balance, refer to Figure 6.11 below.

Figure 6.11 Iran’s gas balance in 2008

6.4.2 The Iranian gas sector

1) Background to institutionalisation and strategy

For Iran, oil and gas revenues accounted for roughly 80 percent of export earnings and of government revenues in 2008 [EIU 2009b; CIA 2009]. Just as many Middle Eastern countries, Iran has emerged from an era during which especially the British and, later on, the US maintained extensive influence in Iran’s energy sector. The Anglo-Iranian Oil Company (later to become BP) held most of Iran’s concessions and operated the oil fields, and the Shah wanted more control over the oil industry [Yergin 1991]. After the 1979 revolution, the new Ministry of Oil cancelled all existing contracts and took control of oil and gas operations through the its own state-owned companies [Marcel 2005]. Since the 1979 Islamic revolution, Iran is re-

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* Iran imported 5.8 bcm from Turkmenistan.
Note: Totals may not add up due to rounding.
Source: own analysis, IEA [2009a].

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a The field’s first five phases totals 45 bcm/y, compared with Qatar’s 28 bcm/y output from its North Field. An additional 9 bcm of incremental production from the existing phases is to come online in 2009 [IEA 2009b].

a In 1920, for example, the British government pushed Iranian officials to accept an ‘interpretive agreement’ which restricted the Iranian government’s entitlement to profits arising in Iran and effectively excluded sales of Iranian oil abroad [Philip 1994].
garded by the US as a major threat to regional energy security, while irony has it that the Shah of Iran was a US ally. US policy has since consisted of imposing economic sanctions on Iran, thus greatly discouraging investment in its energy sector. Iran has never had the opportunity to attract foreign investment to as great an extent as some other major Gulf oil and gas producers and exporters have. In terms of path dependency, therefore, this predicament still influences Iran’s ability to become a gas exporter today.

2) Decision-making

The main actors in the Iranian energy sector are the Iranian parliament, the Majles, (and its Energy Committee), the National Iranian Oil Company (NIOC) and the Iranian Ministry of Oil. Iran’s multi-level, multi-polar political system allows indirect recourse to the wider public will, but maintains decision-making power in a fairly small circle dominated by clerical authorities, at the centre of which is the Supreme Leader’s office. NIOC is practically part of the Ministry of Oil: The Minister of Energy is at the same time chairman of NIOC whilst deputies serve as executives in NIOC subsidiaries [IEA 2008d]. The company is clearly under direct control of the executive government, with other institutions, such as parliament and the Guardian Council acting as centrifugal forces outside it [Marcel 2005]. NIOC has its own host of subsidiaries, which deal with specific geographic regions and fields as well operational tasks such as exploration and production. See Figure 6.12 below for a schematic overview of these relationships.

Handling gas, petrochemicals and refining is done by three sister organisations which formally fall under the Ministry of Oil, while in practice they function as subsidiaries of NIOC. Since the oil nationalisation of 1951, NIOC and its gas arm National Iranian Gas Company (NIGC) have clashed with the various Iranian governments over the collection of oil products and gas rent [Ghorban 2006]. The industry is integrated in the government’s financial system, and therefore the capital needs of the hydrocarbon sector are frequently traded off for those of

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264. Within the Executive Branch, which falls under presidential authority, several bodies influence NIOC directly: the NIOC General Assembly, the Supreme Economic Council and the Petroleum Council. The NIOC General Assembly sets out NIOC’s general policy and approves its budget. It includes the President of the Republic, the Vice President, the Oil Minister, the Energy Minister, the Finance Minister and the Director General of the Management and Planning Organisation. The Supreme Economic Council was founded by Khatami to centralise economic decision-making, deciding most of the development contracts in the energy sector, also pertaining to foreign direct investment. NIOC’s proposed contracts are thus subject to this council’s approval. Ahmadinejad created the Petroleum Council to “protect national interests”, seeking greater control over the oil sector [Brumberg and Ahram 2007].

265. This overview is designed to provide a simplified, perhaps even oversimplified impression of decision-making in the Iranian gas sector. Informal and formal forces may also be at play to such an extent that it is beyond the scope of consideration for this study.

266. These include the National Iranian Gas Company (NIGC), the National Petrochemical Company (NPC) and the National Iranian Oil Refining and Distribution Company (NIORDC). Pars Oil and Gas Company (POGC) is responsible for upstream development and downstream development is divided amongst various firms including the National Iranian Gas Export Company (NIGEC). Both POGC and NIGEC are subsidiaries of NIOC [IEA 2007a].
other ministries [Marcel 2005]. There are thus several important bodies in the Iranian political complex which ultimately influence decision-making in the Iranian energy sector, which have divergent interests, vastly complicating Iran’s gas export plans and ambitions. Iran’s energy policy must cope with domestic needs, balancing them with the various export options.

For example, NIOC and some in the Majles argue that the country should become a major regional and interregional gas exporter on the one hand. The NIOC and National Iranian Gas Export Company (NIGEC) are committed to developing LNG for export [IEA 2007a]. Besides, as they argue, Iran incurs a significant opportunity cost by denying itself a fully fledged role in the international gas industry. As was mentioned, Iranian gas production estimates diverge widely and with rising gas needs at home, Iran is likely to remain constricted in its exports, should they materialise. Therefore one of NIOC’s priorities, after achieving domestic goals, is to become a major gas exporter and enable Iran to become an important gas hub akin to Qatar, filling markets left open by giants such as the latter and Russia [Marcel 2005].

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267 Iran will still have a massive 12 to 14 tcm for export after covering domestic needs and gas re-injection for 50 more years [IEA 2007b]. Be that as it may, NIOC’s plans call for some 100 to 115 bcm to be used for oil injection by 2010, up from 31 bcm per year in 2006 [Flower 2008b]. Part of the development of South Pars is aimed at enhanced oil recovery, namely phases 6 through 8. The new IGAT-5 pipeline will inject gas from South Pars into the large Aghajari oil field of Khuzestan from the large processing plant at Assaluyeh, the landfall point for gas produced from South Pars.

268 The development of marketing of gas on the world market is central to the government’s 20-year plan [IEA 2009b], and NIGC claimed in 2005 that it sought “to achieve 8-10 percent of the world’s gas trade and its by-products within 20 years […]” It is estimated that by the end of 2010-2015, gas exports could reach 248 bcm/y, both as LNG and through pipelines” [Petroleum Economist 2007c].
Some type of ‘neighbourhood policy’ could form the spearhead of Iran’s external energy policy, which could manage energy relations with key potential customers and their regulators such as India and Pakistan, but also with significant Central Asian exporters Kazakhstan and Turkmenistan, as far as supply integration and transit is concerned. It will take quite some years to bring Iran’s export potential up to speed, according to Nozari, the Minister of Petroleum. Iran must first reach a positive balance in which it can produce enough gas for exports [MEES 2008g]. For Iran to be able to manage these different choices effectively, he argues, Iran is in need of an integrated NEF for oil and gas jointly as well as a gas ministry parallel to its oil ministry. Iran’s currently fragmented decision-making process due to the incongruent interests of the actors involved ultimately lead to a number of trade-offs between different priorities. Though Iran does not yet appear to have developed a coherent gas export strategy, it is aware of the external environment in the interregional gas market, and the level of development of important interregional players such as Russia and Qatar, with Iranian oil officials concerned about “established competition” from Algeria, Russia and Qatar. According to one Iranian official “[w]e can’t compete with Qatar. We look for markets where Qatar is not able to get easy access, India and Pakistan, for example [see above], where we have land access and
the Qatari’s would need deepwater pipes in the Indian Ocean and the Oman Sea” [Marcel 2005, p. 166].

3) Foreign investment

Iran’s upstream potential suffers from a shortage of experienced international engineering, procurement and construction contractors [IEA 2007a], mainly because of US and international sanctions (i.e., the Iran Sanctions Act) which restrict Iran’s access to liquefaction technology and equipment [Flower 2008b] and keep IEFs from becoming involved. NIOC has relied on international sources of capital, for example, foreign investment through the buyback scheme, European and Japanese banks and export credit agencies [Marcel 2005]. Iran’s foreign investment policies, based on so-called buyback contracts, are not enticing for foreign investors. Moreover, negotiations between the Iranian bureaucracy and foreign oil and gas companies are generally laborious and unwieldy [Gas Matters 2008d]. Western IEFs are nevertheless prepared to work in Iran but cannot make investment commitments for the aforementioned reasons, which drives Iran to turn to Russian and Chinese firms instead (see below). On paper, the IEFs are still involved in Iran’s upstream LNG projects but their actual participation in the field remains a remote possibility, for the time being.

Iran’s prioritisation of gas resource use is as follows: 1) domestic use of gas, including power generation, 2) gas used for oil lifting, 3) gas-based industries including petrochemical and Gas-to-Liquids (GtL) projects for internal use and export and 4) gas export by pipelines and in the form of LNG [Ghorban 2006].

6.4.3 Domestic gas needs and strategy

Iran consumed the 121 bcm it produced in 2008 [IEA 2009a]. Total primary energy consumption in Iran consisted (in mtoe) of 105.8 mtoe of gas, 83.3 mtoe of oil, 1.3 mtoe of coal and 1.7 mtoe of hydropower (respectively, 43 percent, 55 percent and less than 1 percent for coal and hydropower) [BP 2009]. Thus Iran’s gas uses consist of household and industrial consumption, power generation, injection and some exports while some gas is also flared. According to the EIA, 65 percent of Iran’s gas was marketed, 18 percent was used for reinjection and 17 percent was lost due to flaring [US Department of Energy 2009b]. Mean growth of con-

269 These sanctions were further tightened in 1995 by the Clinton Administration under the Iran Libya Sanctions Act (ILSA), which was aimed at Libya on the same grounds, namely that it funded terrorist organisations. In 2006, Libya was no longer seen as a threat and was thus moved from sanctions list but the Act was extended to 2011 and remained applied to Iran (it was thus renamed the Iran Sanctions Act). The original reasoning behind the Act was that sanctions would curb the strategic threat posed by Iran by hindering its ability to modernize its petroleum sector. American and foreign firms were thus basically barred form investing in Iran.

270 Under the terms of the contract, which may last as short as 5 to 7 years, foreign investors are required to undertake all upstream development and to bear the cost. In return they receive a fixed portion of production, with a pre-agreed rate of return, but control of the fields in question reverts to the NIOC upon completion of development, further discouraging investment [IEA 2007a].
Consumption averages 8.2 percent per year between 2000 and 2007, rising at 7 percent per annum into the foreseeable future. An important factor in Iran’s high energy consumption is, as in many net oil and gas-exporting countries, the high level of energy subsidies, amounting in Iran to just over $55 billion, of which roughly one third is composed of subsidies for gas. Below is a brief account of the most important gas uses in Iran, namely power generation, gas-based industries and gas reinjection:

1) **Power generation:** Power generation needs in Iran were 34 bcm in 2007 (one third of its total consumption) [IEA 2008b]. Through two pipelines (Iranian Gas Trunklines, or IGAT, 1 and 2) transport gas from Iran’s south to its north, around Tehran, where much of Iran’s gas and energy needs, as far as power generation is concerned, is also located in the northeast of the country. This mismatch has led Iran to import gas from Turkmenistan (through the Kurt-Kui pipeline), mainly the Korpedzhe gas field, close to the Iranian border [Olcott 2006]. Iran imported 0.2 bcm from Azerbaijan in 2007 and has expressed an interest in additional gas imports from Phase 2 development of the Shah Deniz gas field.

2) **Gas-based industries:** Gas for consumption by the petrochemical sector was roughly 16 bcm in 2005, representing some 10 percent of Iran’s total gas consumption. Others favour a strategy in which the development of the petrochemical, gas-based industries and other domestic demand needs are given priority [Ghorban 2006]. This increase is part of an effort to diversify the economy away from dependency on oil revenues [IEA 2007a].

3) **Gas reinjection:** Gas reinjection amounted to 30 bcm in 2006. Re-injection is especially attractive when oil prices are high and in the Majles many favour oil lifting, especially in a high oil price environment [IEA 2007a]. According to the IEA, when calculated in $/ per thousand cubic meters ($/mcm), gas used for oil lifting yields $350 when compared to a yield of some $80 from LNG exports to India and almost nil from domestic sales (i.e. subsidies) [Petroleum Economist 2007c]. Gas substitution for oil use in domestic energy consumption is central to the hydrocarbon strategy of Iran, because it frees up lucrative oil for exports [Marcel 2005].

**6.4.4 Gas export ambitions and strategy**

In developing new greenfields for gas exports, Iran already signed a variety of contracts and memoranda of understanding to supply gas, mainly focusing on its regional neighbours, essentially for politico-strategic reasons [IEA 2008d]. In exporting gas outside the ‘near abroad’ region, some experts argue that Iran would especially focus (also for political reasons) on South

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271 Developments in the Iranian Gas Trunkline (IGAT) pipeline series, all fed by South Pars development phases, are important to Iran’s natural gas transport. IGAT-8 and IGAT-9 will be operational in 2009 and 2014, respectively [US Department of Energy 2009b].

272 According to Statfor, there are discussions to increase its Azeri imports substantially to 12 bcm in 2012, [IEA 2008d].

273 At the port of Jask, near the Strait of Hormuz, Iran has recently built one of its largest petrochemical facilities.
Asian countries like India and Pakistan by pipeline, and by LNG to the rest of the world, but primarily to India and China via a dual export strategy combining pipeline and LNG flows [Ghorban 2006]. Iranian officials are aware that the country’s strategic position gives it an advantage over Qatar in that it has the potential to develop a pipeline network to South Asia and, possibly, toward the Mediterranean (and Southeastern Europe) as well [Marcel 2005]. Iran’s gas export priorities can be listed as follows:

1) 'Near-abroad': Gas exports westwards to the Caucasus, Syria and Turkey. Of the volumes exported by Iran, 4 bcm (3.2 percent of Iran’s gas production in 2008) was exported to Turkey via the Tabriz-Erzurum gas pipeline in 2008. The deliveries to Turkey have a contractual maximum of 9 bcm/y, although there were significant difficulties in fulfilling this gas contract, with deliveries averaging 4.5 bcm/y overall. In 2007, a memorandum of understanding was signed between both countries to increase its supplies to a maximum amount of 20 bcm/y (possibly based on phases 22-24 of South Pars development). From 2009 onwards, some capacity will be used during summers for gas supplies (3 bcm/y) to Syria. From the end of 2008 onwards, Iran is to supply neighbouring Armenia with 1 bcm per year. In the long-term it could become a potential supplier, also as a result of planned construction of two pipelines (30 bcm/y) that would be linked to the Iranian east-west pipeline system, combined with three phases of South Pars, of which the Turkish State Petroleum Company (TPAO) had signed a gas production deal that accounts for 20.4 bcm/y [IEA 2009b].

2) 'Near-abroad': exports to the Gulf region: Rapid urban developments in neighbouring UAE and the industrial gas demand in, for instance Oman, offer regional gas export possibilities within the Gulf and is putting pressure on volumes for export [CIEP 2008]. In 2008, Iran and Oman reached an agreement on the supply of Iranian gas from the Kish gas field (located in the Iranian sector of the Persian Gulf, near the Strait of Hormuz) to Oman’s Qalhat liquefaction terminal for further processing (10 bcm/y). Iran may well export humble volumes to other countries in the region as well, including Kuwait (amount yet to be specified), Bahrain (10 bcm/y from 2015 onwards) and the UAE (6 bcm/y from the offshore Salman field) [IEA 2008d]. Most of these volumes will be used for oil recovery.

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274 If Turkmenistan had significant quantities of spare gas and will not supplying Europe via another (new) pipeline, the Turkmen-Iranian-Turkish (TIT) pipeline proposal (30 bcm/y) could be revived, see also case 1 [IEA 2008c].
275 Based on IEA [2008d].
276 Iran is involved in small gas swaps with Azerbaijan (0.8 bcm/y from Azerbaijan) for delivering gas to Nakhichevan and with Armenia (1 bcm to Armenia) in exchange for electricity [IEA 2008d].
277 The aim is to bring about joint exports through a planned 20 bcm/y offshore pipeline, though there is of yet no schedule for the project [MEES 2008g].
278 Iran and Kuwait have recently settled a dispute over the Arash offshore natural gas field in the Gulf, which they will jointly develop and explore [US Department of Energy 2009b].
3) **Potential pipeline gas exports eastwards:** Pakistan and India are important growth markets for gas, lying to Iran’s east. The Iran-Pakistan-India (IPI) pipeline itself is Iran’s main pipeline gas export possibility eastwards, and a large section of the pipeline is already under construction. This segment will be used for domestic gasification in Iran’s southeastern provinces. The project has been on the drawing board since the early 1990s, and various routes had been conceived, but cross-border tensions kept routes on the drawing board. Iran has been in negotiations with Pakistan and India over pricing and transit tariffs, which, in its final of three phases, would reach a capacity of just over 50 bcm/y by 2020 to both India and Pakistan, up from an initial capacity of 22 bcm [IEA 2008d]. The IGAT-7 pipeline from Assaluyeh to Iranshar might be connected to the IPI pipeline at 12 bcm/y worth of capacity to supply Turkmen gas (possibly from the Dauletabad gas field), with the IPI fed by South Pars. Instability in Pakistan and its tense relationship with India has definitely also contributed to delaying the project.²⁷⁹ For now, only Iran and Pakistan are moving ahead with the project. If realised, the IPI project could displace the proposed TAPI pipeline that has been delayed for a number of years due to ongoing instability in Afghanistan (also refer to Chapter 11).

4) **Potential LNG exports:** Next on Iran’s export priority list is gas exports through LNG. Iran could enjoy the same advantage as Qatar does (see next section) in being equidistantly positioned between the Atlantic and Pacific LNG basins, meaning it could aim for a wide variety of LNG export diversification. While oil is the primary source of export revenues, LNG and pipeline gas exports are being pursued as long-run development options [Flower 2008b]. Several Iranian LNG export projects have been on the drawing board for a number of years but have been stalled, with foreign partners unwilling to commit to Iranian projects due to sanctions and the wider (perceived) political risks. Iran’s LNG projects are all centred on development of the South Pars field, the development of which is structured in 24 phases spanning 20 years (phases 1 through 5 are complete, phases 6 through 10 came on-stream behind schedule).²⁸⁰

As is mentioned above, despite Iran’s challenging investment climate, some foreign players in the form of both IEFs and NEFs are aiming for a stake in Iran’s upstream. NIOC has been keen to award new phases of South Pars development that are geared to supplying

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²⁷⁹ The project faces delays due to price uncertainties, macro and regional (geo)political forces, cross-border complexities in relation to technicalities and regulatory issues, combined with undeveloped gas markets [Boon von Ochssee and Shahryar 2009].

²⁸⁰ Phases 11 to 14 have been allocated to LNG production, although phase 12 will also supply the domestic market [Flower 2008b]. For a complete overview of the phases and the respective production planning of the South Pars field, see [IEA 2009b].
gas for domestic use (see above), but some phases of South Pars’ development are dedicated to eventual exports. Iran’s slated LNG projects include Persian LNG, Iran LNG and Pars LNG. Persian LNG (6.5 bcm/y, based on phase 11) is to be developed by NIOC (50 percent) Shell (25 percent) and Repsol (25 percent), but these two companies temporarily withdrew in mid-2008. Pars LNG (7.75 bcm/y, based on phases 13 and 14) was supposed to be developed by NIOC and foreign partners Total and Petronas.  

Iran LNG (6.5 bcm/y, based on phase 12) is to be developed by Österreichische Mineralölverwaltung (OMV) and Iran LNG Company but is also experiencing delays, some of its output is already dedicated to Indian buyers. However, like Shell and Repsol, Total was compelled by the US Iran Sanctions Act (ISA) act to refrain from investing in Iran in July 2008, and its 30 percent stake in the project may be awarded to China’s CNPC, which has also been negotiating for a stake in the project [WGI 2009c]. In March 2009, China’s National Offshore Oil Corporation (CNOOC) and NIOC signed a contract for the development of the North Pars gas field, a deal in which CNOOC receives half the production in exchange for construction of upstream and downstream (it has already begun drilling at the field) [PIGR 2009a].

5) Potential pipeline gas exports westwards: From the Iranian point of view, Iranian exports further on to Europe currently have a low priority because of domestic gas needs and gas export priorities to the other markets named above. According to the IEA, it is unlikely that there would be enough production capacity to supply additional volumes to Europe in the mid-term. According to the IEA’s data, the aforementioned commitments add up about 45 bcm/y (58 bcm/y; including LNG production) by 2012 and a further 22 bcm/y (50.08 bcm/y; including LNG production) soon after. According to the IEA [2008c], it is doubtful as such whether Iran, an oft-cited source for potential volumes for the Nabucco pipeline, will have enough production capacity to supply even only phase 1 of Nabucco (earlier Russian activities in the Turkish market may also play a role, Gazprom supplies over half of Turkey’s gas needs, see Case study 1, Chapter 9).

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281 For example, Statoilhydro operated phases 6-8 of South Pars have output dedicated to the domestic market; these have finally come onstream in 2008.
282 Phase 13 is located close to the maritime border with Qatar, and despite any conclusive evidence to support its claim, NIOC has stated that it is preoccupied that any imbalance between Qatari production from the joint North Field/South Pars reservoir will cause gas migrating to the Qatari side [Gas Matters 2008d].
283 The only pipeline commitment to a European supplier was made in March 2008 with the Swiss energy company Elektrizitäts-Gesellschaft Laufenburg AG (EGL) for gas deliveries (5.5 bcm/y) via the existing Iran-Turkey pipeline and the aforementioned Trans-Adriatic pipeline to EGL’s power plants in Italy [IEA 2008d].

156
6.4.5 Cooperation with other gas-exporting companies

Apart from potential cooperation with IEFs and Chinese NEFs in some of its LNG projects, Iran has increased its cooperation with other NEFs. Cooperation on the following focal points has been discussed, mainly concerning long-run cooperation:

1) **Upstream development:** In August 2003, both Russia and Iran signed an agreement on issues of bilateral cooperation in the sphere of oil and gas [Zhiznin 2007]. Gazprom already completed phases 2 and 3 of South Pars and agreed to participate in future phases of the project [IEA 2009b].

2) **Joint Russo-Iranian ventures:** In July 2008, Gazprom signed a memorandum of understanding with NIOC covering 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 [IEA 2008d]. Both countries agreed to set up a joint venture in the form of an energy company to explore investment opportunities in Iran, Russia and other countries. Also covered in the agreement is a plan for Gazprom’s cooperation on developing the IPI and IGAT-7 pipeline projects, gas swaps and the building of a refinery in northern Iran [WGI 2009i]. As mentioned in the section concerning the Caspian Sea, Gazprom and NIOC are discussing potential volumes from Turkmenistan to Iran (under a swap arrangement), this would be supplied in return for Gazprom’s access to Iranian LNG from the South Pars field [WGI 2009i]. Iran is also looking to position itself as an important transit corridor for gas from Caspian Sea producers, seeing itself as the logical transfer point for all Caspian Sea energy, a position fully supported by NIOC since it stood to benefit from any direct revenue generated by a trans-Iran pipeline [Brumberg and Ahram 2007]. Therefore Iran is studying possibilities for a 12 bcm/y north-south gas pipeline that could accommodate flows from these producers to the port of Jask, next to the Oman Sea [IEA 2008d].

3) **The South Pars project:** Remarkably, in November 2008, Russia, Iran and Qatar agreed on setting up a venture to jointly develop other phases of Iran’s South Pars field. In an apparent extension of bilateral cooperation already in place between Russia and Iran, it is the first such proposal for trilateral cooperation between the three largest gas reserve holders. Talks encompassed trilateral gas exploration, production, processing and transportation, including LNG, involving the set-up of a joint venture. All three countries’ NEFs would take an equal 30 percent share each, and would consider offering the remainder to a fourth partner. The joint venture proposal comes just three weeks after all three coun-

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284 The joint venture can be seen “as part of the ongoing discussions between Russia, Qatar and Iran on expanding cooperation, Gazprom representatives will participate in meeting of a technical committee that will discuss details of the implementation of the joint South Pars project” [PIGR 2008b].

285 The project entails producing gas at South Pars, building a pipeline across the Gulf to Qatar and building an LNG plant at the industrial hub of Ras Laffan [PIGR 2008b].
tries established the so-called Gas Troika in October 2008 (to be discussed in Chapter 10).

6.4.6 Iran’s geopolitical and geo-economic relationship with Russia

Iran’s geopolitical role for Russia is an important one that indirectly affects Russia’s energy policies with regard to Iran. Even though Iran does not yet play an important role in the inter-regional gas market, Russia and Iran do have important geopolitical interests within and around the Eurasian gas ellipse. For this reason, Iran’s geopolitical relationship with Russia is explained in this section, concerning mainly the following:

1) Russia became more responsive to Iranian interests in the early 1990s as Russia began seeking its own foreign policy course [Dekmejian and Simonian 2003]. Both countries share the Caspian Sea, located on either side (North and South) and have common interests vis-à-vis the other littoral states (also see Chapter 11). Russia has concluded bilateral deals with Kazakhstan and Azerbaijan on the question [Amineh 2003]. Russian and Iranian positions over the legal status of the Caspian Sea only partially coincide [Zhiznin 2007]. Iran’s aims for its share of the Caspian Sea are 20 percent of the seabed, overlapping with Azerbaijani and Turkmen claims [MEES 2008e].

2) Russia and Iran have important commercial ties in the arms and nuclear energy sectors. Continued access to Iran’s ports in the Gulf is also important for Russia [Dekmejian and Simonian 2003].

3) Iran is a rising power in both the Central Asian and Persian Gulf regions. It thus also exerts much influence on the Islamic world in Central Asia and the Caucasus [Amineh 2003]. From a geopolitical perspective, Russia sees Iran as an important partner in stabilising Central Asia and the Caucasus, with both countries perceiving one another as strate-

Historically, the Soviet Union agreed with Iran that both countries should equally share the resources under the seabed. The uncertainty surrounding the status of the Caspian Sea as either a very large lake or a small sea has major implications for the distribution between the various littoral states of gas resources under the surface of that body of water’s floor. Russia’s sector of the coastline has regressed since the collapse of the Soviet Union and both countries now hold smaller coastlines. During the 1990s, IEFs and Western government, the US in the lead, became increasingly involved in attempts to achieve a legal definition of the Caspian Sea as a lake, which would result in an equal share for all the littoral states, making it possible to open up the seabed to international investments [International Herald Tribune 2007a]. Both Russia and Iran have since blocked any resolution in an effort to forestall such an outcome and continue to lobby for the definition that will yield them the greatest possible share of the Caspian Sea’s subsoil resources [Klevemann 2003]. If it is a lake, there are no obligations by countries that flank it to grant permits to foreign vessels or drilling companies. But if it is defined as a sea, there are international treaties obliging those countries to an array of permits. In the ‘sea’ case, the UN Convention on the Law of the Sea of 1982 would be applicable while in the ‘lake’ case, customary international law concerning border lakes would apply. The Caspian Sea does not seem to be a sea, a lake or a condominium. Its final legal status must be determined by unanimous agreement among all the littoral states [Janusz 2005].

It is widely known that Russia has delivered to Iran various kinds, including surface-to-air missiles, while it also cooperates with Iran on its nuclear programme in which Russian companies have commercial interests [Amineh 2003].

Rather than being one of two non-Arab states on the northern periphery of a predominantly Arab Middle East, Iran now saw the potential to be the centre of gravity of a new enlarged Middle East that included the non-Arab peoples of Central Asia and the South Caucasus [Herzig 2001].
gic partners in the region and requiring coordination [Dekmejian and Simonian 2003; Amineh 2003]. Iran fears unrest in its northern border areas and appreciates the presence of Russian military units in the Caucasus and Central Asia [Pannier 1999].

4) A mean feature of Russia’s interactions with Iran have been to further advance Russian interests in the two geographical areas that Iran straddles, the Caspian Sea and the Persian Gulf [Lee 2007]. From a purely geo-strategic point of view, Iran acts as a bulwark for Russia against total US hegemony in the Persian Gulf region, and by extension ultimately also in Central Asia [Le Monde Diplomatique 2006]. For Russia, closer cooperation with Iran is a reaction to NATO expansion towards Eastern Europe and the Black Sea, Western aims to secure energy resources in the Caspian Sea region and intensive Turkish activities in Central Asia [Amineh 2003]. Russia also actively supports Iran’s membership in the SCO, and sees the US effort isolate Iran as counter-productive [Kommersant 2007]. Both countries see the US as an important rival, and have seen the construction of the BTC and the South Caucasus Pipeline (SCP) as open US challenges to their control of oil and gas flows in the Caspian Sea region. They can thus help one another in excluding or limiting US influence in the region.

5) Russia has an interest in seeing Iran maintain a status quo in the Gulf and Central Asian regions, even though historically both countries have mostly been rivals.

The geopolitical importance of Iran for Russia reinforces the geo-economic one. Therefore in addition to the points mentioned above, Iran’s role for Russia also relates to the following as far as gas is concerned in particular (more geo-economic elements than geopolitical):

1) As will be shown in case studies 1 and 2 in Chapter 9, Iran may be a source of potential competition for gas market share in Europe given the relatively low costs to market and its reserve size. In the long run, Iran could act as an interregional LNG supplier, similar to

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289 In 1999, Kozyrev had already remarked “a strategic parity had to be established between Iran and Russia to ensure stability in Transcaucasia and Central Asia” [Pannier 1999].

290 According to a retired Russian General in the Russian foreign intelligence service, Gennady Yefstafiev: “The US long-term goals in Iran are obvious: To engineer a downfall of the current regime, to establish control over Iran’s oil and gas, and to use its territory as the shortest route for the transportation of hydrocarbons under US control from the regions of Central Asia and the Caspian Sea bypassing Russia and China, this is not to mention Iran’s intrinsic military and strategic significance.” Quoted in an interview, titled ‘An OPEC for natural gas,’ [Radio Free Europe 2007]. In this interview PFC energy analyst Nikos Tsafos and RFE/RL energy analyst Roman Kupchinsky discussed with an RFE/RL briefing what the likelihood is of a natural-gas-producers consortium being formed and what such an organisation might look like.

291 A US-Turkish-Azerbaijani axis, which arose during the 1990s, made a close Russian-Iranian ties a geopolitical imperative [Dekmejian and Simonian 2003].

292 Even in 1999, when Yeltsin was still in power, one of his advisors was quoted as saying: “We will not let the West dictate to Russia how far it can go in its relations [with Iran]” [Pannier 1999].

293 In October 2007, Putin also visited Iran to show both solidarity with Iran and other neighbouring Caspian Sea countries in wanting to resolve the legal status of the Caspian Sea [International Herald Tribune 2007b] and to warn the US against attacking Iran by using bases in any of the Caspian Sea countries [International Herald Tribune 2007c].
Qatar, and as a pipeline supplier to Asian markets. Also, it should not be forgotten that both Russia and Iran remain competitors for the transit of Caspian oil and gas [Dekmejian and Simonian 2003].

2) Russia and Iran have an interest in arm’s length cooperation to jointly maintain control over Central Asian gas, as they control two of the most important exit routes for gas from the landlocked Central Asian region. For Russia, Iran acts as a ‘geo-economic’ pivot in that Central Asian gas is forced either northwards to Russia or southwards to Iran. Yet Russia does oppose the transit of Central Asian gas through Iran, especially to Europe [Amineh 2003].

3) By extension, both countries have an interest in limiting US influence in the region. The US acts as a common foe as it attempts to create gas export routes to bypass both Iran and Russia (see below). This includes trans-Caspian gas transport routes from Kazakhstan and Turkmenistan to Azerbaijan and beyond, westwards as well as from Azerbaijan itself (mainly from the Shah Deniz field, see above).

It occupies the most sensitive geo-economic position within the Eurasian gas ellipse, in between the Persian Gulf and Central Asia, forming the ideal transit corridor for gas (and oil) from Central Asia to the Persian Gulf, to Europe via Turkey and East towards South Asia [Noreng 2006]. Under a pro-US regime, an Iran open to foreign direct investment in the same manner as Iraq now is could also act as a major conduit for Central Asian gas, away from Russian control. In the long run, this could expose a vast bulk of the Eurasian gas ellipse to (private) foreign investment, ultimately at Russia’s expense.

### 6.5 Conclusion

The inner integrators are bound to play an important role as far as pipeline gas flows are concerned on the Eurasian continent. Russia, with the largest reserves and in and of itself well-positioned geographically to supply both Europe and China, is an important Lynch-pin amongst the inner integrators. Dominated by Gazprom, Russia’s domestic gas sector is in transition. The IGPs could play an important role in alleviating the call on Gazprom’s investment needs, even as limited attempts have been made at liberalising Russia’s domestic gas market. In the meantime, Central Asian gas volumes will remain important for Russia’s gas balance. These landlocked gas-exporting countries will, in all likelihood, continue to seek export outlets as alternatives to exporting gas to Russia, an effort in which China increasingly plays an important role as a potential export market. Of these suppliers, Turkmenistan is the most important, potentially holding much more gas reserves than previously expected. Russia sees the latter as part of its own privileged sphere of influence, especially as far as gas is concerned.

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294 In early 2007, Iran began negotiations with other Caspian Sea littoral states such as Turkmenistan in order to come to swap arrangements.
As the second largest conventional gas reserve-holder in the world after Russia, Iran has enormous export potential. Like Russia, Iran is also well-positioned to export gas to multiple markets both by pipeline and LNG (to Europe and markets in the Asian subcontinent). In addition, Iran could also develop as an important LNG exporter in a manner similar to Qatar, given its position midway between the Atlantic and Pacific basins. However, US-led sanctions and the corresponding lack of access to advanced technology, capital and know-how, the complex nature of Iran’s decision-making process and high domestic gas needs cast a long shadow over Iran’s gas export potential. So long as these obstacles remain, Iran’s huge gas reserves are not likely to play any significant interregional role, in terms of either pipeline or LNG. Iran and Russia have a special geopolitical and geo-economic relationship. Iran plays an important role in both the Gulf and Central Asia regions. On the one hand Iran is a potential source of competition in the form of alternative pipeline gas flows to Europe; on the other both countries not only have common geopolitical interests but also shared geo-economic ones. Gazprom is expanding its reach in Iran’s upstream and is participating in the pipeline project slated to export gas to Pakistan and India.