FOREWORD

The Caspian region contains some of the largest undeveloped oil and gas reserves in the world. The intense interest shown by the major international oil and gas companies testifies to its potential. Although the area is unlikely to become "another Middle East", it could become a major oil supplier at the margin, much as the North Sea is today. As such it could help increase world energy security by diversifying global sources of supply.

Development of the region's resources still faces considerable obstacles. These include lack of export pipelines and the fact that most new pipeline proposals face routing difficulties due to security of supply considerations, transit complications and market uncertainties. There are also questions regarding ownership of resources, as well as incomplete and often contradictory investment regimes.

This study is an independent review of the major issues facing oil and gas sector developments in the countries along the southern rim of the former Soviet Union that are endowed with significant petroleum resources: Azerbaijan, Kazakstan, Turkmenistan and Uzbekistan. *Caspian Oil and Gas* complements other IEA studies of major supply regions, such as *Middle East Oil and Gas* and *North African Oil and Gas*. It also expands on other IEA studies of the area, including *Energy Policies of the Russian Federation* and *Energy Policies of Ukraine*.

The study was undertaken with the co-operation of the Energy Charter Secretariat, for which I would like to thank its Secretary General, Mr. Peter Schütterle.

Robert Priddle
Executive Director

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Map 1

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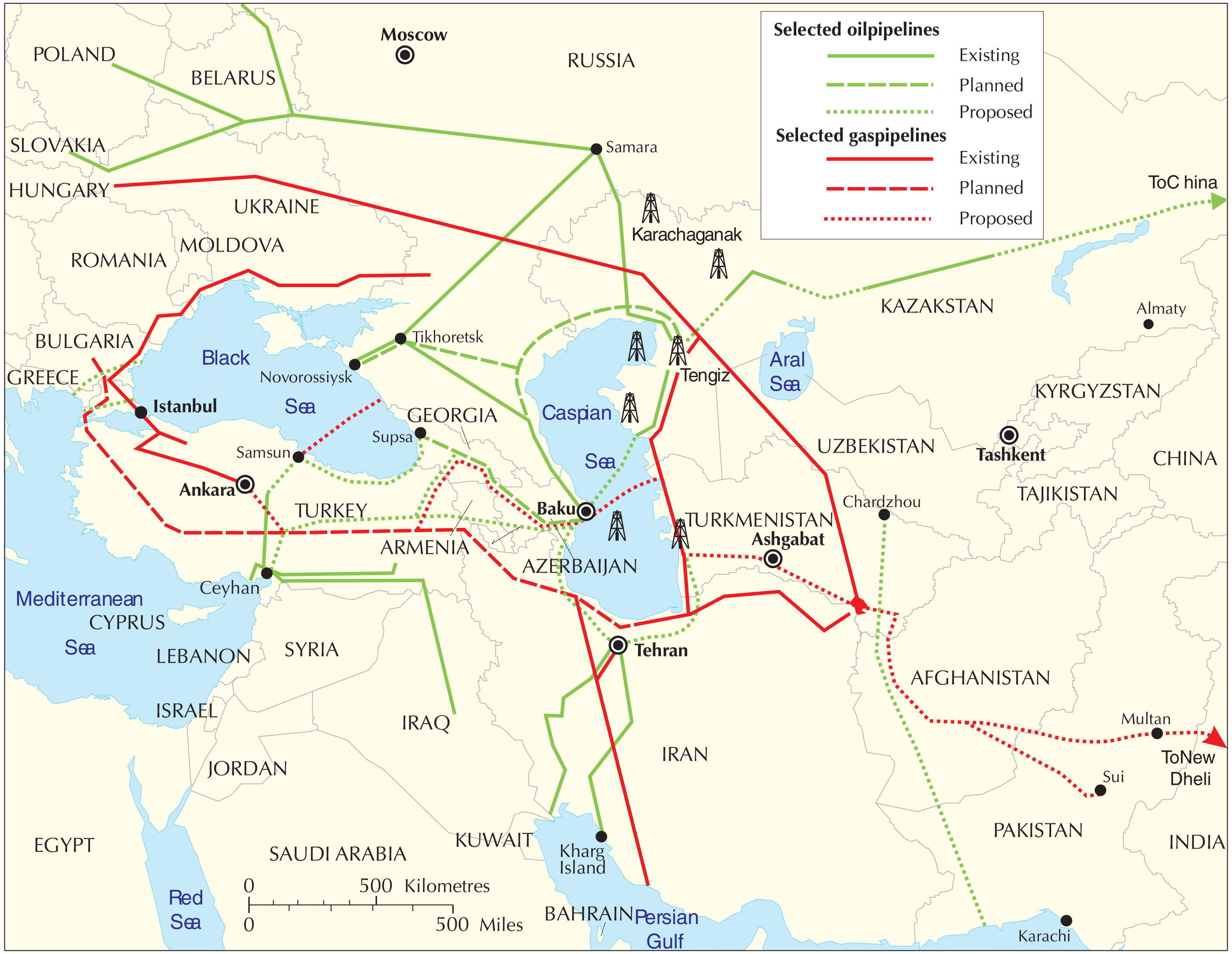

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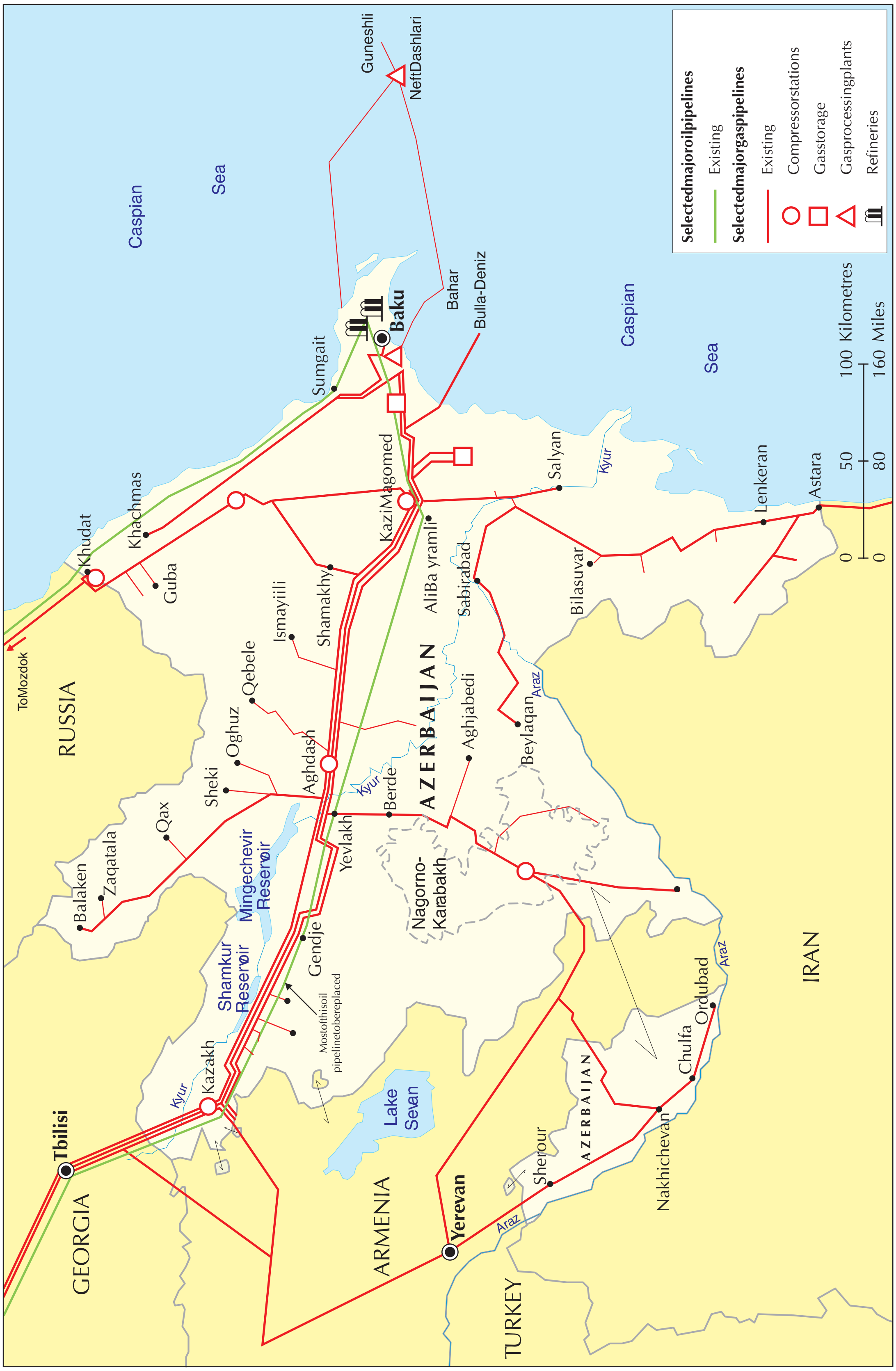
Map 2

Azerbaijan: Major oil and gas infrastructure



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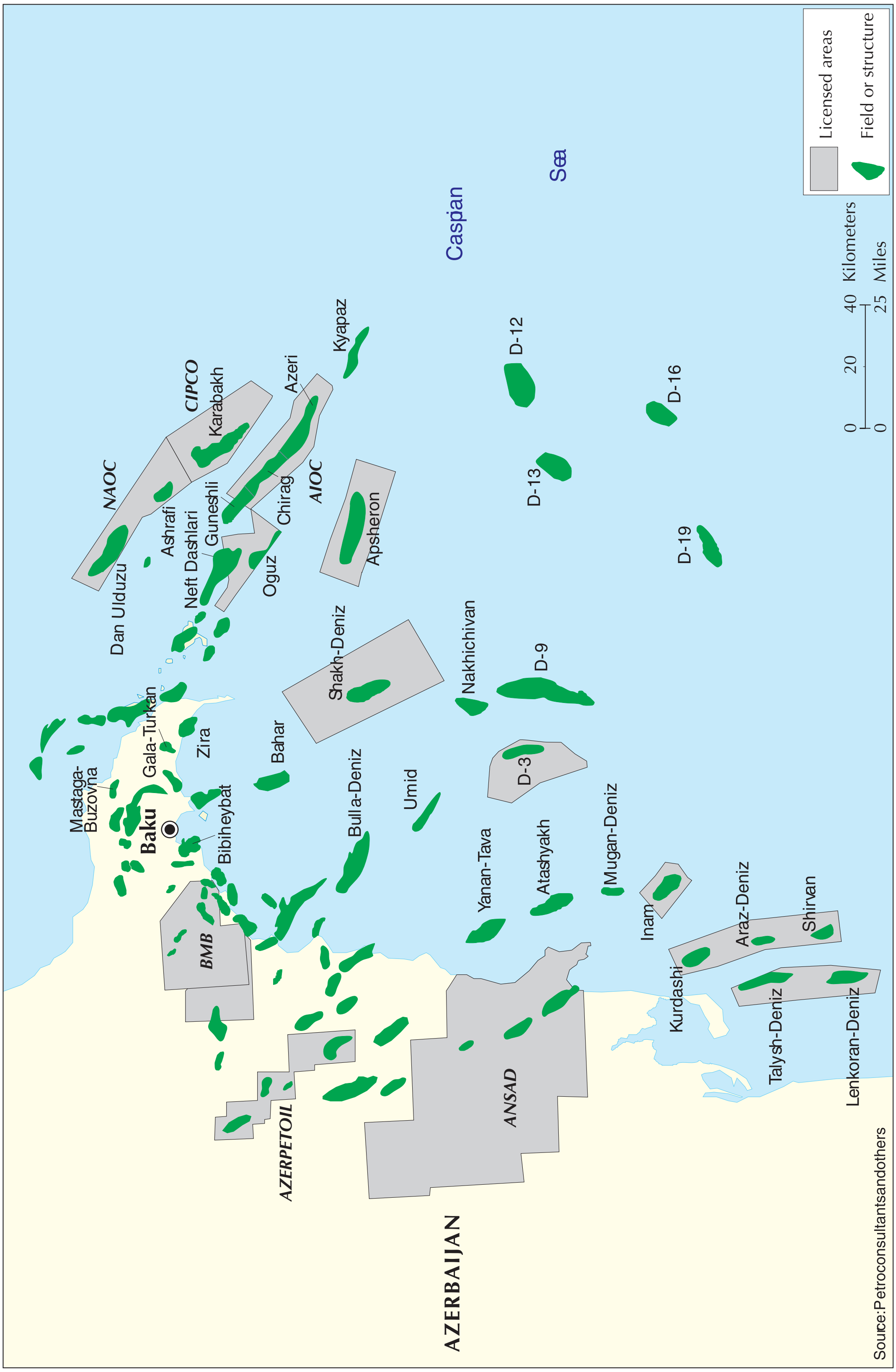

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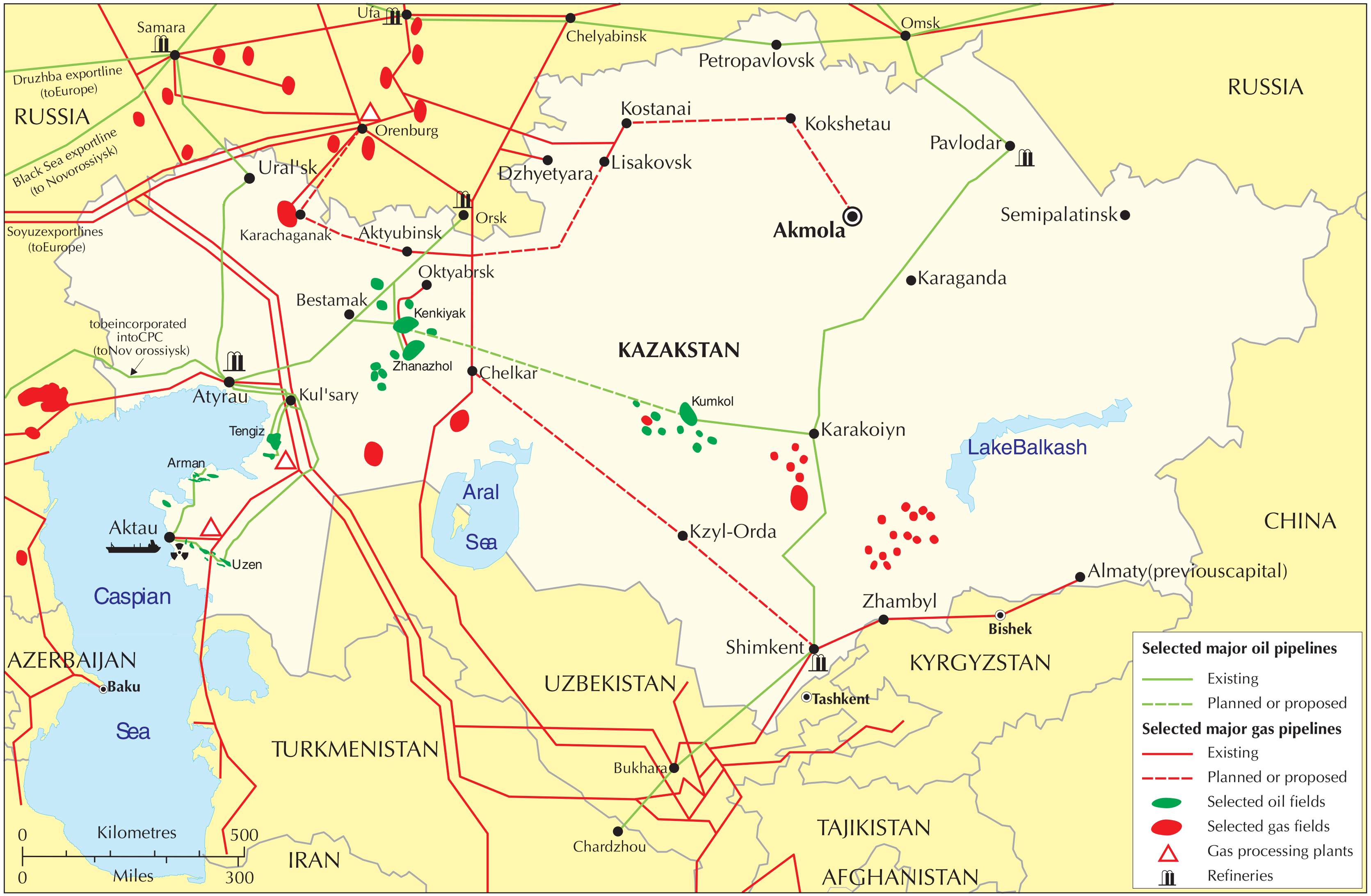

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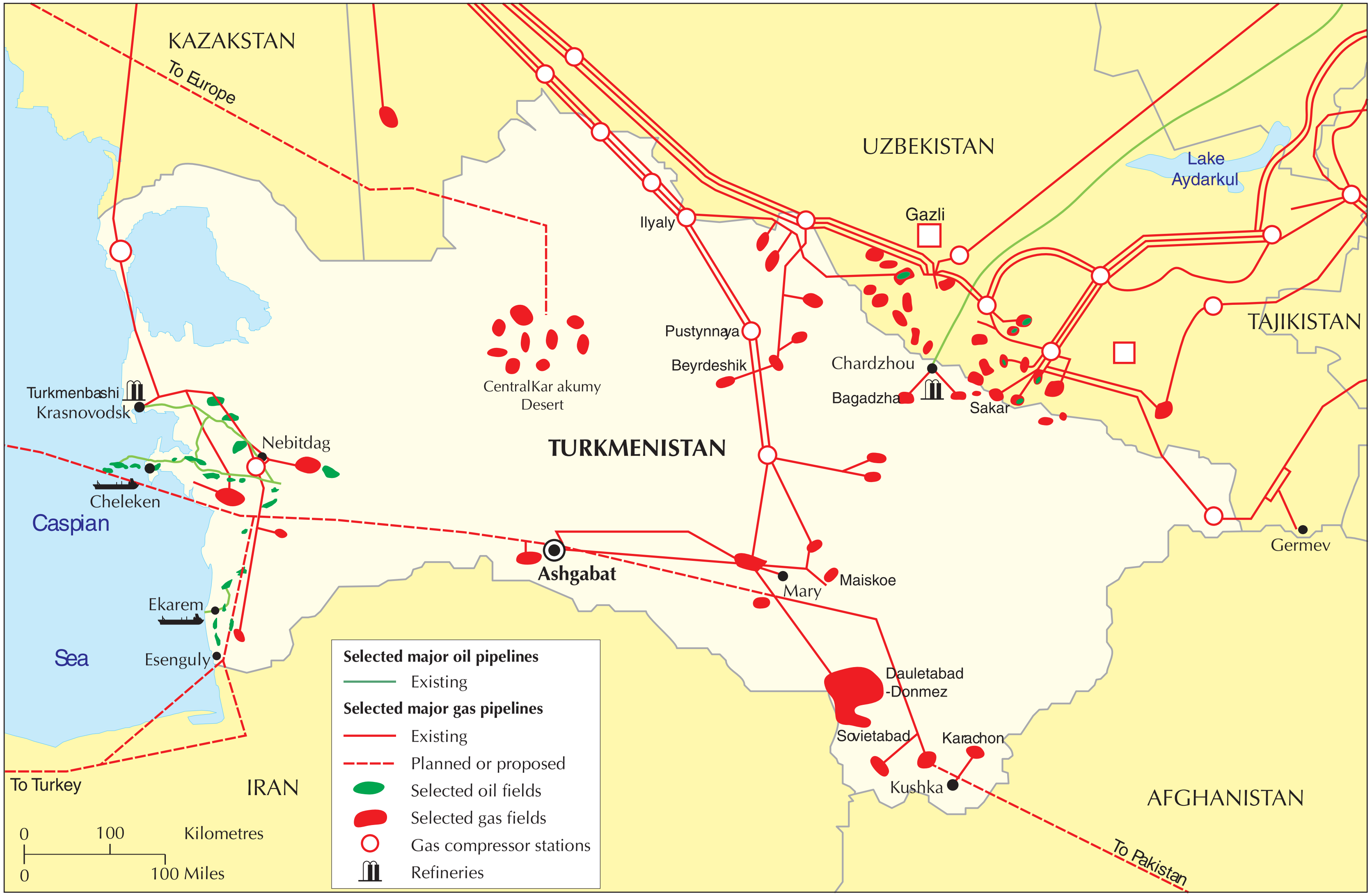

Map6

Uzbekistan:Majoroilandgasfieldsandinfr astructure

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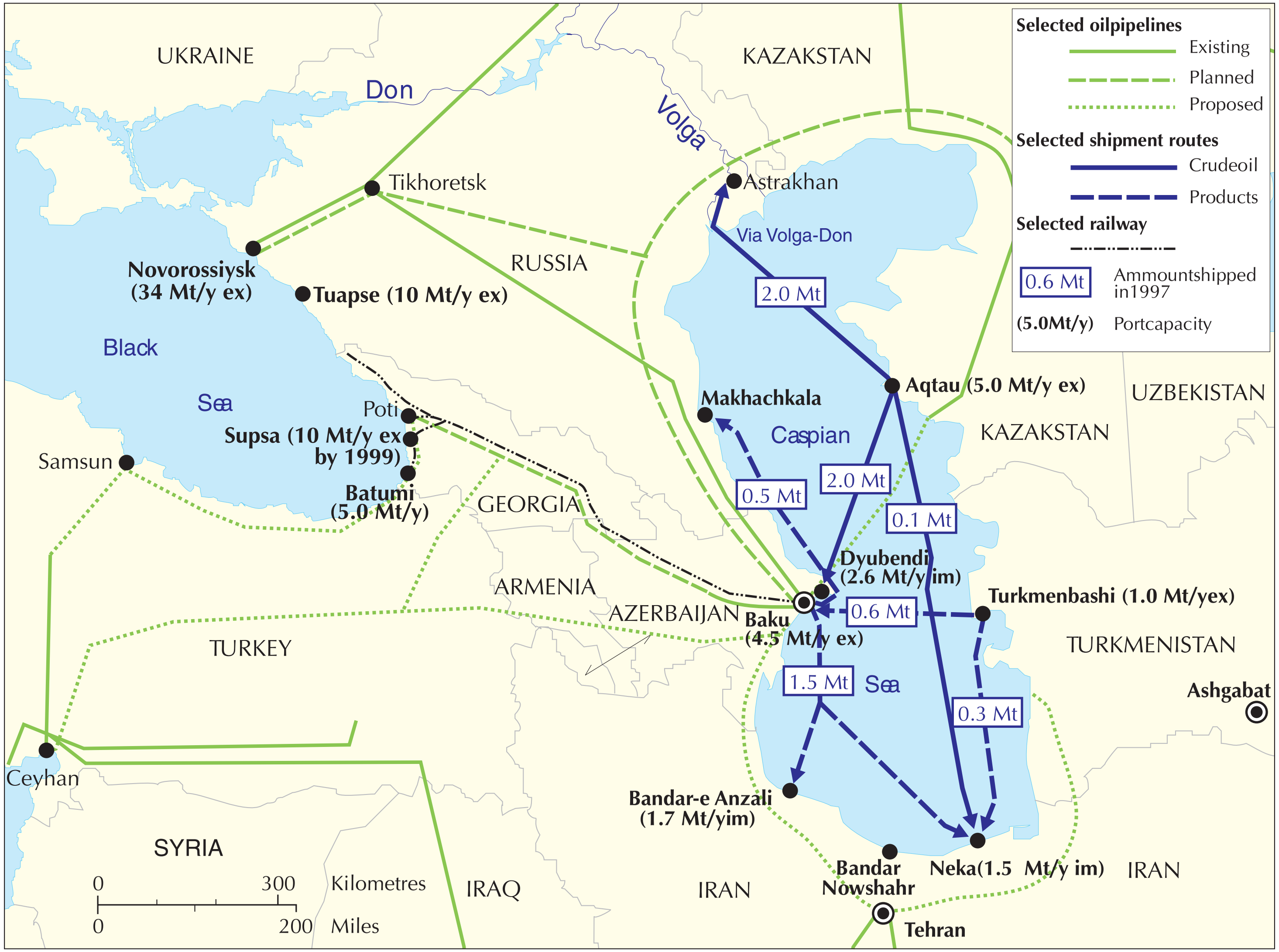


INTRODUCTION

The IEA, in co-operation with the Energy Charter Secretariat, conducted a study of the oil and gas sectors of Azerbaijan, Kazakstan, Turkmenistan and Uzbekistan in late 1997 and early 1998. The product, Caspian Oil and Gas, is an independent review of the major issues facing oil and gas sector development in the region.

In preparing this report, missions were undertaken in late 1997 to the four countries covered by this survey to meet with key energy sector players in government and industry, both local and foreign, as well as representatives of multilateral institutions active in the region.

The study team was composed of experts from the IEA Secretariat and its Member Countries and from the Energy Charter Secretariat. The members of the team were:

Hans Kausch (Team leader)
IEA, Head, Non-Member Countries Division for Europe, Middle East and Africa

Philip Swanson (Editor and principal author)
IEA, Principal Administrator, Non-Member Countries Division

Janusz Bielecki
IEA, Principal Administrator, Emergency Preparedness Division

Robert Ebel
Center for Strategic and International Studies, Washington DC, USA

Sydney Fremantle
Energy Charter Secretariat, Senior Advisor

Randolph Gränzer
IEA, Principal Administrator, Non-Member Countries Division

Edgard Habib
IEA, Principal Administrator, Non-Member Countries Division

Richard Hildahl
Energy Resources Group, Steilacoom WA, USA

Slavtcho Neykov
Energy Charter Secretariat, Advisor

Ottar Skagen
Statoil, Stavanger, Norway

OVERVIEW

THE REGION

This study focuses on the countries along the southern rim of the former Soviet Union that are endowed with significant oil and gas resources: Kazakstan, Turkmenistan and Uzbekistan in Central Asia, and Azerbaijan in Transcaucasia.[1] Several neighbouring states are also covered in the discussions of oil and gas transportation and markets.

The Caspian region is re-emerging on the world energy scene. Commercial oil output began in Baku in the mid-19th century, making Transcaucasia one of the world's first oil provinces. In Central Asia, on the other side of the Caspian Sea, commercial production began in the early part of the 20th century.

By 1940, Azerbaijan accounted for about 70% of Soviet oil production. Nevertheless, some of the known deposits were in difficult locations or geological formations that required extraction technology unavailable to the Soviet oil industry. Russia, on the other hand, contained resources that were readily more accessible. Concerns over Baku's vulnerability to attack during World War II, along with the discovery of oil in the Volga-Urals region of Russia and later in western Siberia, led to a switch in USSR investment priorities. Moscow transferred resources away from Transcaucasia and Central Asia; the new policy resulted in decreased exploration and production in the region.

The political and economic liberalisation of the Soviet Union in the mid-1980s caught the attention of foreign investors, among them oil and gas companies interested in exploration and production opportunities. Foreign companies renewed their interest in Baku and were also attracted by possibilities on the other side of the Caspian Sea.

The break-up of the Soviet Union brought further opportunities for the liberalisation of investment regimes. It also brought initial instability in some countries and obliged potential investors to re-start business negotiations from scratch. In some cases the process repeated itself several times as governments changed. By the late 1990s, the region was relatively stable politically, and a number of countries had made significant progress in attracting investment to their oil and gas sectors.

1. For the purposes of this study, Caspian region, Central Asia and Transcaucasia refer to the major oil and gas producers Azerbaijan, Kazakstan, Turkmenistan and Uzbekistan. Central Asia and Transcaucasia otherwise also include Kyrgyzstan and Tajikistan in the former, and Armenia and Georgia in the latter.

RESERVE BASE

Estimates of proven oil reserves in Central Asia and Transcaucasia vary between 15 and 40 billion barrels, with about 70 to 150 billion barrels of additional reserves considered possible. Estimates of the region's proven natural gas reserves are between 6.7 and 9.2 trillion cubic metres, with perhaps 8 trillion cubic metres of additional reserves possible.[2] This represents 1.5% and 4% of the world's proven oil reserves, and 6% of its gas reserves. Since much of Central Asia and Transcaucasia remains to be explored, the region's known reserve base could increase significantly.

PRODUCTION AND EXPORT POTENTIAL

If investments continue at the current pace, and if sufficient export outlets are developed, the IEA "high" case scenario projects annual oil production from the four countries of the study to reach 79 million tonnes (Mt) or 1.6 million barrels per day (Mb/d) by 2000, and 194 Mt (3.9 Mb/d) by 2010. In the "low" case scenario, which assumes some project delays, oil production by 2000 would reach 69 Mt (1.4 Mb/d), and 138 Mt (2.8 Mb/d) by 2010.

Gas production in Central Asia and Transcaucasia will depend on a number of factors, including: the development of export markets, the outcome of negotiations with Russia over access to Gazprom pipelines, the pace of new export pipeline construction and domestic consumption. The level of reserves is not a binding constraint, and probably will not be for a long time. Consequently, forecasting gas production is extremely difficult. Current IEA predictions are for gas production to reach 112 billion cubic metres (Bcm) by 2000 and 201 Bcm by 2010 in the high case. In the low case, production would reach 102 Bcm by 2000 and 164 Bcm by 2010.

Table 1 Caspian region production

	1996	2000	2010
Oil (Mt)	43	69 - 79	138 - 194
Gas (Bcm)	96	102 - 112	164 - 201

Table 2 Caspian region net exports

	1996	2000	2010
Oil (Mt)	15	29 - 33	75 - 117
Gas (Bcm)	25	26 - 31	72 - 84

2. Sources surveyed for both oil and gas resources include forecasts by governments in the region, Petroconsultants, PlanEcon, and the US government (see for example, Report to Congress on Caspian Region Energy Development, 1997).

Figure 1 Oil production, domestic consumption and net exports (high case)

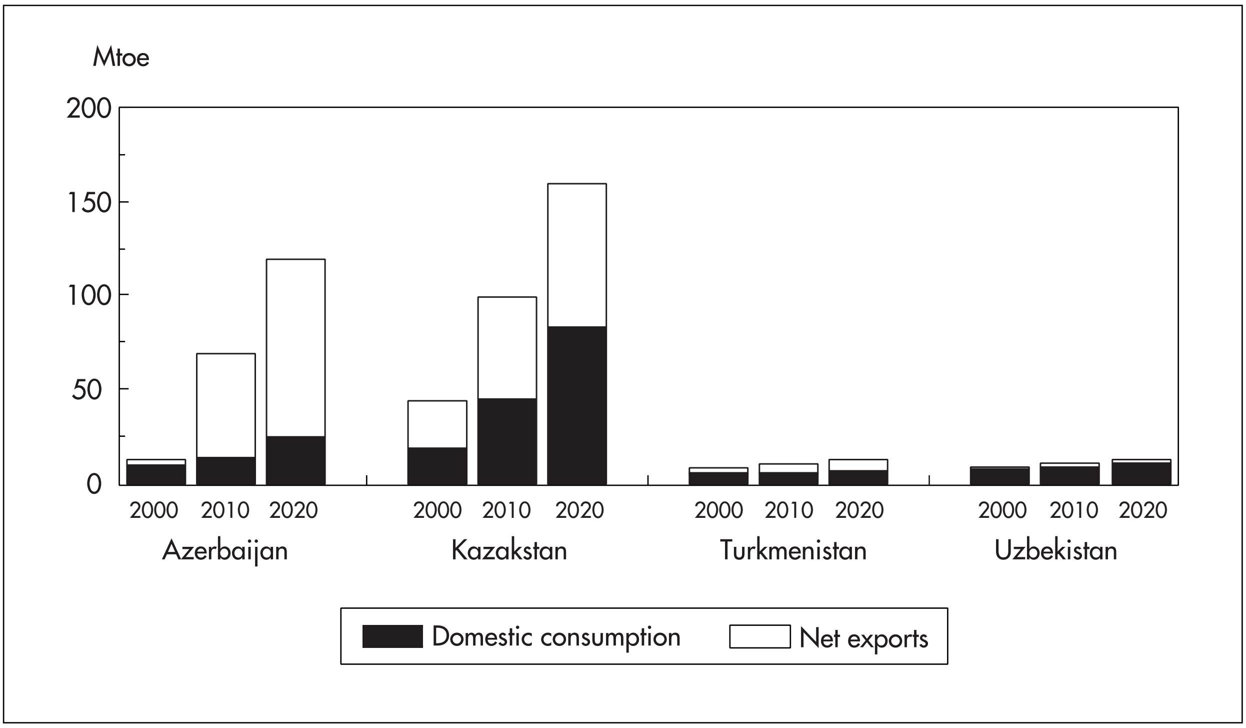
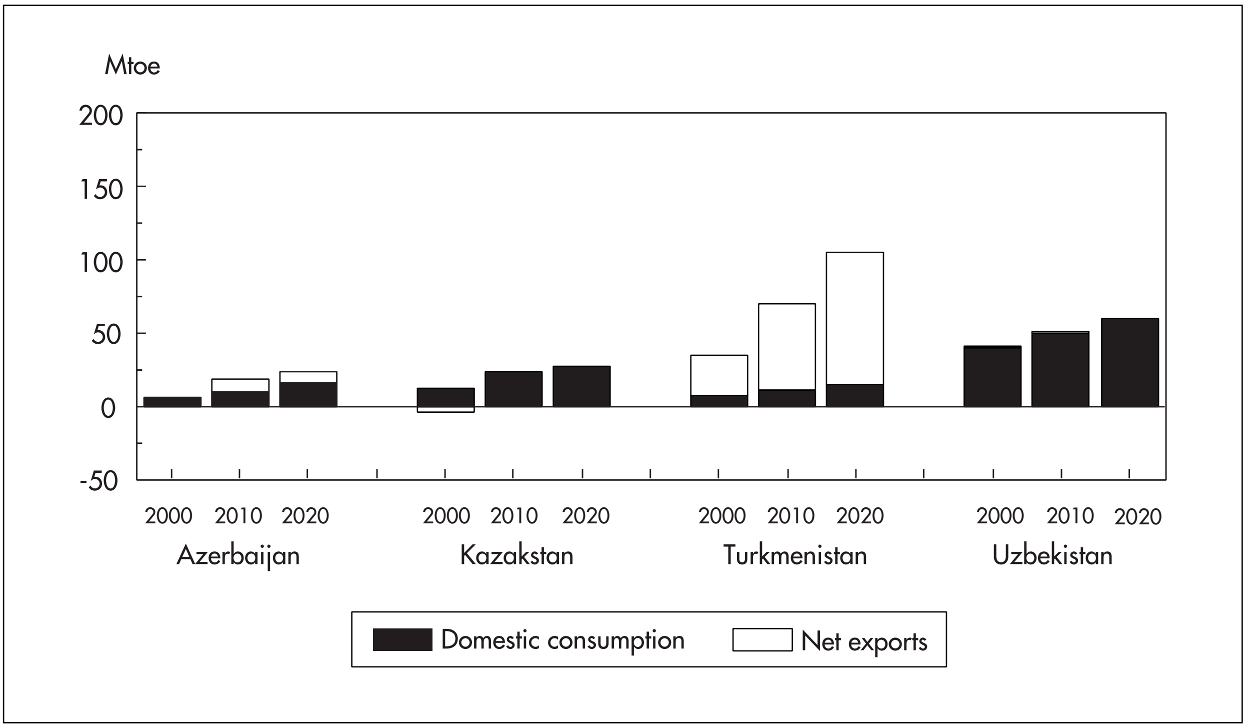


Figure 2 Gas production, domestic consumption and net exports (high case)



Providing that agreed pipeline projects are built to plan, and taking into account domestic consumption, the IEA estimates that oil and gas available for export from the region will be about 33 Mt (0.6 Mb/d) and 31 Bcm by 2000. These figures would rise to 117 Mt (2.3 Mb/d) and 84 Bcm by 2010. In the "low" case scenario, oil exports would be 29 Mt (0.6 Mb/d) and gas exports 26 Bcm by 2000, and 75 Mt (1.5 Mb/d) and 72 Bcm by 2010.[3] Production and exports beyond 2010 are expected to be significantly larger. (More detailed IEA projections may be found in the chapter, Projections of oil and gas production, domestic demand and exports).

IMPORTANCE AS ALTERNATIVE SOURCE OF SUPPLY

The Middle East holds some 65% of the world's proven oil reserves and 30% of its proven gas reserves. In 1996 it supplied more than 40% of its internationally traded oil. Dependence on Middle Eastern oil is forecasted to increase significantly by 2010 as production outside the Persian Gulf region lags behind world demand.

The Member Countries of the International Energy Agency (IEA) and the Energy Charter Treaty (ECT) recognise the importance of energy security, of which diversity of supply is an essential component. A number of regions in the world act as important alternatives to the Middle East as sources of tradeable oil. These include western Africa, Mexico, South America, the North Sea, and the former Soviet Union. Although their surplus capacity is relatively small, all of these regions (with the possible current exception of the FSU) could increase oil supply at the margins in the event of a supply disruption.

Although the Caspian region is unlikely to become "another Middle East", most observers consider that its resources will be on the same order of magnitude as those of the North Sea. As such, it could be a significant alternative source of oil and gas supply, helping to increase world energy security.

OIL AND GAS IN THE ECONOMIC DEVELOPMENT OF THE REGION

The development of oil and gas resources in the Caspian region is particularly important for the development of the Central Asian and Transcaucasian economies.[4] Investment attracted to the oil and gas sector, including in the transportation infrastructure of neighbouring countries, could provide significant revenue for the region's governments and stimulate investment in other economic sectors.

Regional governments should be mindful, however, of the possible negative effect which the development of one tradeable commodity can have on other industries. For example, it could bid up the prices of inputs for other exported goods (e.g., as happened when the Netherlands began exporting significant amounts of gas in the late 1960s).

3. Domestic consumption is different under the "high"and "low" scenarios, due to the effect that changes in the level of oil development are expected to have on economic growth.
4. In 1995 the energy sector's share of GDP was an estimated 14.6% in Azerbaijan, 10.1% in Kazakstan, 10.2% in Turkmenistan, and 11.1% in Uzbekistan.

Governments should take prudent steps to ensure the development of an adequate legal and administrative infrastructure, including institution building and personnel training, to handle the inflow of oil-based revenues and to help ensure the countries' efficient and equitable development. Significant oil revenues will probably start accruing to some governments in the region around 2005, after the cost recovery period of the early major projects. There is some concern expressed, notably by the IMF, that unless regional governments introduce further administrative reforms, they risk being overwhelmed by new oil wealth. Corruption could be a particular danger.

Economic development stimulated by investment in the oil and gas industry will help ensure the financial independence of the young Central Asian and Transcaucasian states. Investment in appropriate legal and administrative infrastructure is one way to safeguard this independence.

INVESTMENT

The Central Asian and Transcaucasian region is rich in natural resources. However, economic dislocations caused by the collapse of Soviet-era logistical relations and the transition to a market economy have left governments with insufficient funds to develop these resources. (Fully developing and transporting Central Asian and Transcaucasian oil and gas reserves may cost up to US$200 billion.) Governments are looking to private investment, in particular from foreign companies, to play an important role in unlocking their oil and gas production and export potential.

Foreign investors not only bring financial resources; they can also help transfer up-to-date technology to local industry, including environmentally sound production methods, as well as training in modern management techniques.

The Central Asian and Transcaucasian countries are competing with other regions for investment. Oil and gas companies have a wide choice of where to put their money and will always choose the opportunities that offer the best financial returns. The investment climate is at least as important a consideration as the reserve base in an oil company's decision on where to invest.

Kazakstan and Azerbaijan in particular have made significant strides in creating attractive investment climates. The former has concentrated on building a body of law applicable to all projects, while the latter has focused primarily on tailored production sharing agreements. (Further information on investment climates may be found in the Investment framework chapter and in the Investment section of individual country chapters.)

By the beginning of 1998, cumulative foreign direct investment in the oil and gas sectors of Central Asia and Transcaucasia had reached an estimated US$3 billion, nearly one third of which was placed in 1997. Future investment obligations in the region from contracts already signed total over US$40 billion.

So far most foreign investment has been in Kazakstan and Azerbaijan. In Uzbekistan the government has favoured loan-financed projects under which foreign companies perform services on a contract basis, usually without equity interest. Gas-rich Turkmenistan is hoping to attract foreign investors, but started somewhat later than the others in opening its doors. (Descriptions of major projects may be found in the Investment sections of the individual country chapters.)

The Energy Charter Treaty

Azerbaijan, Kazakstan, Turkmenistan and Uzbekistan have all ratified the Energy Charter Treaty, which came into force in April 1998. Part III of the Energy Charter Treaty covers the promotion and protection of investments by firms from other Contracting Parties, which include all OECD countries except New Zealand, the Republic of Korea, the United States and Canada, as well as many non-OECD countries. The Treaty applies to all investments in "exploration, extraction, refining, production, storage, land transport, transmission, distribution, trade, marketing or sale of energy materials or products". It requires signatory governments to treat the existing investments of an investor from another Contracting Party no less favourably than those of its own investors and the investors of any other country. A supplemental treaty, to be signed in 1998, will determine the conditions under which this principle will apply to the admission of new investments. An important feature of the Energy Charter Treaty is its mechanism for dispute resolution.

As Treaty signatories, the Central Asian and Transcaucasian countries have grace periods before they must fully implement some of the detailed provisions of the Treaty, although each has already introduced legislation to implement some of its more important requirements. (More information on the Energy Charter Treaty may be found in the Investment framework chapter.)

OIL AND GAS EXPORT ROUTES

The lack of adequate export infrastructure is probably the most difficult problem facing investors in the oil and gas sectors of Central Asia and Transcaucasia. The construction of new export pipelines has become a priority. However, most routing options are fraught with technical, financial, legal and/or political difficulties.

Inherited infrastructure

The oil and gas pipeline systems of Central Asia and Transcaucasia were originally designed and built to serve the needs of the Soviet Union. As such, they often cross the borders of its successor states. All oil and gas export pipelines inherited from the Soviet period pass through Russia. Russia's oil and gas pipeline operators, facing capacity constraints due to lack of maintenance and other technical problems, have capped exports from the region. In the case of gas, there is also a certain reluctance to share markets.

In 1996, the capacity of crude oil export pipelines from Central Asia to Russia was about 16 Mt, with virtually no export capacity from Transcaucasia. This capacity has been nearly fully utilised in recent years. For onward export capacity, shared by Russian and Central Asian oil, Transneft has allocated less than 10 Mt per year to Central Asia.

The situation is more difficult for gas. Since 1994, Gazprom has not allowed any exports through its territory to markets outside the former Soviet Union. Gazprom has furthermore indicated that it does not want Central Asian gas to compete with Russian gas in the lucrative European market. Gas exporters from Turkmenistan, Kazakstan and Uzbekistan have thus been limited to less solvent markets of the FSU.

The need for new pipelines

By 2010, Central Asia and Transcaucasia could have over 100 Mt of oil and 100 Bcm of gas available for export. Even if there were no other limitations on exports from the region, existing oil and gas pipeline capacity would not meet future export needs. Additional oil and gas export pipelines are being proposed and in some cases are already under construction to serve the region. The most advanced projects are for the transport of oil, particularly the AIOC consortium's "early oil" pipelines from Azerbaijan, and the Caspian Pipeline Consortium's line from Kazakstan. A small gas pipeline between Turkmenistan and northern Iran was completed at the end of 1997.

Multiple pipelines

Most proposed pipelines must pass through or near politically troubled areas, including Nagorno-Karabakh, Chechnya, and Afghanistan. This has given rise to concerns that some pipelines could become vulnerable targets for terrorist activity.

The existence of multiple export routes could increase the energy security of both exporters and importers by making exports less subject to technical or political disruptions on any one route. However, energy security will have to be balanced by economic feasibility, since a larger number of pipelines would mean smaller economies of scale and greater expenses for each project.

Russia's Transneft may allow more oil to transit Russia as that country's spare export capacity increases. Spare capacity may rise after 2000, as Russian domestic demand grows and as domestic oil prices approach world levels, cutting Russian producers' incentive to export. Moreover, some scenarios show Russian oil output declining again, due to a continuing lack of investment. These developments may help reduce pressure for rapid development of some new export pipelines from Central Asia and Transcaucasia. However, the existence of alternative pipelines could increase the incentive for the Russian oil pipeline company, Transneft, to remove the bottlenecks in its substantial existing spare capacity[5] and offer competitive transit arrangements. Similar incentives may arise for the export of gas, although in the case of gas the situation will be more complicated by the issue of market share.

Export markets

Oil from Central Asia and Transcaucasia could compete strongly with Russian crude in the European and Mediterranean markets, as it is generally of higher quality and cheaper to produce. Russia's southern refiners could also opt to purchase cheaper crudes from Kazakstan and Azerbaijan. China, which has concluded a number of investment deals in the Kazak oil sector and has plans to build a pipeline to western China, could become an important market in the medium to longer term.

5. In 1996 the capacity of crude oil export pipelines exiting European Russia was some 225 Mt per annum, while actual exports from Russia to destinations outside the FSU were only about 100 Mt, and to other FSU countries about 20 Mt (mainly Ukraine and Belarus). The difference was due to market limits (Hungary, Slovakia, Ukraine and Belarus) and physical constraints at other export destinations. Many physical constraints could be overcome by market incentives and regulatory reform in Russia. For example, producers could be given access rights for participating in export expansion projects to relieve bottlenecks.

The most likely markets for gas from the region are Europe and South Asia. However, Central Asian and Transcaucasian exporters could face strong competition in almost all markets from established, closer suppliers, and from an array of would-be suppliers; particularly Iran and various Middle Eastern and North African states. Closer to home, Ukraine could become an important gas market once payment problems abate. Russia may find it cheaper to meet its incremental domestic needs with imported gas (freeing up gas for export) than to further develop the Yamal peninsula. (More information on markets are provided in the chapters, Markets for Caspian region oil, and Markets for Caspian region gas.)

Transit and the Energy Charter Treaty

The Energy Charter Treaty requires that member countries facilitate the transit of oil and gas to or from other member countries; not impose more onerous terms on transit traffic than on goods originating or destined for their own territory; not impede the construction of new transit capacity if access to the existing capacity cannot be gained on commercial terms; and refrain for up to 16 months from interrupting a transit in order to enforce a claim in a dispute. However, like the rest of the Treaty, the transit provision has yet to be tested in practice.

Selected oil and gas export proposals

The following are among the main proposals for new oil and gas export routes from Central Asia and Transcaucasia. More details for some projects may be found in the relevant country chapters. (Cross references are provided in parentheses.)

Proposals for oil exports

AIOC oil pipelines from Azerbaijan

The major oil export pipeline projects originating in Azerbaijan are co-ordinated by the AIOC consortium, which is also developing the offshore Azeri, Chirag and Guneshli fields. In October 1995 it was decided to split AIOC's "early oil" (pre-peak production) between two export routes; the "northern route", to be constructed to Russia's Black Sea port of Novorossiysk, and the "western route", to Georgia's Black Sea port of Supsa. The northern route was opened in December 1997. An important issue for this pipeline has been the division of responsibilities and transit revenues between Russia's Transneft and the local Chechen oil company, through whose territory the pipeline passes. Both the northern and western pipelines will have an initial capacity of 5 Mt per year. More capacity will probably be required by 2003. In July 1997 the AIOC announced that it had narrowed the possible routes for the so-called "main oil" (peak production) pipeline to three, from which it is to choose one by October 1998: expanded versions of the two routes used for early oil, plus a third route to the Turkish Mediterranean port of Ceyhan. (See p. 162)

CPC oil pipeline from Kazakstan to the Black Sea via Russia

The most advanced alternative export route from Kazakstan is the Caspian Pipeline Consortium (CPC) project to build a pipeline to a new loading facility near Novorossiysk.

Construction of the CPC line is to begin in 1998. The pipeline, whose schedule has slipped several times, is expected to be operational in 2001 with an initial capacity of 28 Mt/year, to be expanded to 67 Mt/year by about 2012. A major problem has been obtaining rights of way from Russian regions. (See p. 213)

CAOP oil pipeline from Turkmenistan to Pakistan via Afghanistan

Unocal (US) and Delta Oil Company (Saudi Arabia) propose to build a crude oil export pipeline from Chardzhou, Turkmenistan, via Afghanistan to a terminal on the Pakistani Arabian Sea coast. The so-called Central Asia Oil Pipeline (CAOP), with an envisaged capacity of 50 Mt/year (1 Mb/d), would have to transit some 700 km of politically unstable Afghan territory. Fields in both the Turkmen and Uzbek portions of the Amu Darya basin, as well as the Kumkol field in central Kazakstan, could be connected to the CAOP. The CAOP project is linked to a similar pipeline for gas, which is expected to precede it. (See pp. 251, 285)

CNPC pipeline from Kazakstan to China

An oil export route to China became more of a possibility when China National Petroleum Corporation (CNPC) acquired Kazak oil producer Aktobemunai and exclusive negotiating rights to Kazakstan's Uzen oil field in mid-1997. Since such a pipeline would probably have to cross much of Kazakstan, it could also provide a valuable link between production and consumption centres within the country. Many observers remain sceptical about the economics of such a project, the construction of which was promised by CNPC as part of its Aktobemunai acquisition. Some have pointed out that the project is viewed as a strategic one by China. Moreover, if the pipeline were routed via China's Tarim basin, Central Asian oil plus Tarim oil might provide the critical mass to justify a pipeline to Chinese consumption centres in the East. (See p. 218)

Trans-Caspian oil pipeline from Kazakstan or Turkmenistan

Several parties have proposed constructing an oil pipeline under the Caspian Sea from Kazakstan or Turkmenistan to Azerbaijan and onward to western markets, perhaps hooking into the AIOC main oil pipeline. Such a route may be an alternative to pipelines for sending Central Asian oil westward via either Russia or Iran. However, construction of trans-Caspian pipelines could be complicated by environmental concerns and the uncertainty of territorial boundaries in the Caspian Sea. (See p. 219)

Non-pipeline alternatives

The Tengizchevroil project sent almost half its 1997 oil exports by rail to various destinations, including the Baltic States and Odessa, and by ship to Azerbaijan, from where the oil was sent by pipeline and rail across Georgia to the Black Sea. In addition, the Kazak government has sent limited amounts of oil across the Caspian by tanker to Iran in swap arrangements for oil in the Persian Gulf. Several companies operating in Turkmenistan are also shipping oil via Baku and investigating swaps with Iran. (See pp. 213, 219, 220)

Proposals for gas exports

Gas pipeline from Turkmenistan to Turkey via Iran

Since 1993 Turkmen authorities have promoted the construction of a gas export pipeline from Turkmenistan via Iran to Turkey. Initially, a pipeline with a capacity of 15 Bcm per year has been planned with a view to supplying the Turkish market. Future upgrades to 28 - 30 Bcm per year are envisioned in order to supply markets further west. Pursuit of this line is complicated by US sanctions legislation on projects involving Iran. (See p. 255)

Gas pipeline from Turkmenistan to Iran

In late 1997 Iran completed a 200-km pipeline from southern Turkmenistan to north-eastern Iran, where it is to link up with an existing pipeline to power stations in north-western Iran. This line may be incorporated into the project to export gas to Turkey. Turkmenistan will see little revenue from this project for several years, since gas deliveries will be used to reimburse Iran for construction costs. (See p. 255)

Trans-Caspian gas pipeline from Turkmenistan

Several parties have proposed constructing a gas pipeline under the Caspian Sea from Turkmenistan, near the Kazak border, to Azerbaijan and onward to Georgia and Turkey. Like the trans-Caspian route for oil, it offers an alternative to pipelines via either Russia or Iran. (See p. 257)

Gas pipeline from Turkmenistan to Pakistan via Afghanistan

Following a memorandum of understanding signed in 1993, Bridas (Argentina) proposed building a pipeline from Turkmenistan through Afghanistan to Pakistan, with a planned annual capacity of around 20 Bcm and the possibility of extending the line to northern Indian markets. In 1995 the Bridas project appeared to lose favour when the Turkmen government signed another memorandum of understanding with a consortium composed of Unocal (US) and Delta (Saudi Arabia), which is also planning an oil pipeline through Afghanistan. Unocal and Delta would purchase 20 Bcm/year at the Turkmen border and market it at their own risk. Bridas claims it is still pursuing its version of the pipeline and has taken the rival consortium to court. However, the major problem for both is the lack of political stability in Afghanistan, through which both pipelines would pass. Questions have also been raised about whether future Pakistani demand alone will be enough to justify such a pipeline, while any extension to India would entail overcoming political difficulties between the two South Asian neighbours. (See p. 258)

Gas pipeline from Turkmenistan to China

In 1994 Turkmenistan and China signed a memorandum of understanding to build a 28-Bcm gas pipeline from Turkmenistan, via Uzbekistan to the east coast of China, with the possibility of deliveries to Japan either through a pipeline extension or as LNG by ship. If routed near China's Tarim basin, the pipeline might provide the possibility of moving Chinese gas to market as well. The main problems are the costs involved in building such a long line, the complexities of dealing with three or more transit countries, and uncertainty about the competitiveness of Turkmen gas in east Asian markets. There is even some question about Turkmenistan's ability to supply the amount of gas necessary to amortise the project, especially in light of simultaneous negotiations on other large-scale export projects. (See p. 259)

The Turkish Straits

An important issue for the development and transportation of Central Asian and Transcaucasian resources is the transit of oil through the Turkish Straits. Currently, most oil exported from the region goes via the Russian Black Sea port of Novorossiysk. Several oil pipelines being built also terminate on the Black Sea. From there, most of the oil passes through the Turkish Straits to reach world markets.There is concern that future oil exports could significantly increase tanker traffic through the Straits, thereby raising the chance of serious accidents that could pose environmental and safety threats to human and marine life. Besides environmental concerns, there are security of supply concerns about sending all oil via one route. An accident in the Straits, besides causing environmental damage, could also disrupt the flow of oil from the Caspian region. Building alternative routes, such as pipelines that avoid the Turkish Straits, could increase the security of supply of Caspian oil, and boost its value as a supplement to Middle East supplies. (Further discussion of the Turkish Straits may be found in the chapter, Marine transportation in the Caspian and Black Seas and the Turkish Straits.)

Iran

Iran is considered an attractive export route for oil and gas between Central Asia and Europe, and for oil from both Central Asia and Transcaucasia to the Persian Gulf. It already has a well developed oil and gas infrastructure, including portions of pipeline that could be used for the routes mentioned above or for swaps.[6] By some estimates, an Iranian route could prove significantly cheaper than other proposed pipelines. Iran is also seen as an alternative to transport via Russia.

However, sanctions have been imposed on Iran as a result of accusations that the Iranian government is supporting international terrorism and developing weapons of mass destruction. In order to limit resources available for such activities, the United States placed Iran under a comprehensive trade and investment embargo in 1995; it prevents American companies from trading with or investing in Iran. In 1996 the United States passed the Iran and Libya Sanctions Act, which requires the US President to impose sanctions on anyone investing US$40 million or more in the development of Iranian or Libyan petroleum resources.The investment threshold dropped to US$20 million with respect to Iran in August 1997. Such sanctions could make it difficult for any pipeline project involving Iran to obtain financing. It is presently unclear to what extent the election in 1997 of a new Iranian president could open an opportunity for dialogue on such issues.

Aside from sanctions, there could be security of supply concerns related to oil transported via Iran. Central Asian and Transcaucasian oil sent via the Persian Gulf would be subject to the same potential bottleneck as much of Middle Eastern crude if flows were disrupted through the Strait of Hormuz. Moreover, future Iranian policies regarding transit oil are uncertain.

As a Caspian littoral state, Iran will also play an important role in the development of oil and gas resources in parts of the Caspian Sea. All Caspian littoral countries will have to co-operate closely on a number of issues, in particular the protection of the marine environment of the Caspian Sea. Iran, which shares borders with both Turkmenistan and Azerbaijan, is a neighbour

6. Iran may be able to handle up to 650 kb/d in oil swaps. However, the level of investment needed to fill infrastructure gaps would probably exceed that allowed by current US sanctions legislation.

with whom the Central Asian and Transcaucasian states are keen to maintain good relations. As an important trading route and partner, Iran already exerts considerable economic and political influence. Its ability to do so could increase significantly if it were to become a major transit route for Central Asian and Transcaucasian energy exports.

ENVIRONMENT

There are a number of environmental issues related to the development of oil and gas in Central Asia and Transcaucasia. The most important are pollution in the Caspian Sea and liability for past environmental damage.

The Caspian Sea is a fragile ecosystem, in part because its closed nature causes the natural self-cleaning process to be slower than in bodies of water connected to the ocean. The Caspian contains a number of species particularly sensitive to increases in water pollution, including the sturgeon, which is the cornerstone of the region's economically important fishing industry.

Azerbaijan, which has the most developed offshore oil industry among the literal states, presently accounts for much of the oil sector-based pollution in the Caspian Sea. Azerbaijan's onshore oil industry, much of which is located near the coast on the Apsheron peninsula, is also a significant polluter, as are its coastal refineries. However, most pollution in the Caspian Sea probably comes from other sources, including other industrial sectors in other states, both on the coast and inland along the rivers that empty into the sea. Perhaps the single largest source of pollution is the heavily industrialised Volga River system.

In the oil and gas sector, Azerbaijan is defining new environmental limits for future consortia comparable to those in the North Sea and Gulf of Mexico. Existing production sharing agreements with foreign companies contain strict environmental provisions. Other littoral states are also making progress in this area. However, enforcement of existing regulations is hampered by lack of monitoring equipment and trained personnel. The United Nations Environment Programme, World Bank, EBRD and the EU-TACIS programme, among others, have been assisting littoral governments in these areas. There is a bi-lateral agreement between Azerbaijan and Kazakstan on environmental standards for the Caspian, though negotiations have some way to go before the emergence of a multilateral environmental agreement among all littoral states.

The rising water level of the Caspian Sea also presents environmental problems, including the flooding of coastal on-shore oil fields, many of which are surrounded by oil "lakes" from inadequate environmental management in the past.

A concern for many foreign investors is the uncertainty regarding liability for past environmental degradation. In the case of many older on-shore fields, environmental damage has been severe. Although current legislation prescribes standards for current and future output, it is often unclear regarding responsibilities for environmental damage that occurred prior to new investments.

International oil companies have worked hard over the past years to develop good environmental credentials and a "clean" image. They may therefore be reluctant to invest in fields in the region where substantial environmental degradation has been sustained, unless such damage can be rectified at reasonable costs. To clean up the problems of the past, and to induce investors to work at such fields, governments may need to develop a comprehensive system of guarantees and incentives.

LEGAL STATUS OF THE CASPIAN SEA

A large portion of oil and gas reserves in Central Asia and Transcaucasia are thought to lie under the Caspian Sea.The question of the ownership of those resources, including the right to license and tax their development, is being debated by the Caspian littoral states. The continuing legal uncertainty, however, does not appear to have significantly slowed recent investment in the Caspian Sea. Favourable geological prospects, with expectations of a major resource base, provide significant incentives for companies to be present in this important producing region, preferably from the start of its development. Companies also seem to be confident that, because agreements have been signed with a large number of companies coming from a variety of states, these agreements will be honoured. (Further discussion of this issue may be found in the chapter, Legal status of the Caspian Sea.)

PROJECTIONS OF OIL AND GAS PRODUCTION, DOMESTIC DEMAND AND EXPORTS

SUMMARY

This chapter examines the future output, domestic consumption and available surplus for exports of Central Asian and Transcaucasian oil and gas. Two supply scenarios are used. Implicitly the "high" scenario assumes that present plans and projects will be implemented according to schedule or be replaced by new ones with little time delay, and that additional projects will be developed on the basis of favourable exploration results. The "low" scenario assumes that some plans and projects will be delayed for technical, economic or other reasons and that fewer additional projects will be developed.

For each of the eight energy supply scenarios (one high and one low for each of the four countries) a corresponding energy demand scenario has been developed. It is based on assumed GDP growth estimates (which are influenced by the energy supply scenarios), assumed changes in the structure of GDP in three sectors ("energy", "non-energy industry" and "non-industry"), estimates for specific energy consumption per unit of output in these sectors, and population projections and energy consumption per head for households. Energy available for export is obtained as the difference between energy supply and demand estimates, although some consideration of the influence of access to export markets on production is made in the case of gas. Tables on the supply, demand and output scenarios and on the economic assumptions behind them, may be found in the statistical annex to this chapter.

Total oil production in the four countries was 41 Mt in 1995 with exports of 9 Mt. By 2010 production is expected to reach 194 Mt in the high case and 138 Mt in the low case, with exports of 117 Mt and 75 Mt, respectively.

Gas production, which was 97 Bcm in 1995, is expected to reach 201 Bcm in 2010 in the high case and 164 Bcm in the low case, with exports reaching 84 Bcm and 72 Bcm, respectively.

Over the second decade of the next century oil and gas output and exports are expected to grow at lower rates, though in terms of additional output the increase will be as large as in the first decade. In the high case, oil export volumes will grow less in absolute terms than in the first decade, and by 2020 should reach 178 Mt in the high case scenario. The four countries economies are assumed to grow faster than their oil and gas output. Due to continued energy efficiency improvements, they will consume a smaller percentage of production domestically than in the previous decade. In the low case, oil exports by 2020 are expected to reach 148 Mt.

Growth rates in gas output in the second decade of the next century are also expected to decline, particularly under the low scenario. Exports are predicted to reach 120 Bcm in the high case and 116 Bcm in the low case.

SUPPLY SCENARIOS

Oil and gas reserves for the region have yet to be fully assessed, although the general consensus is that they will not be a major limiting factor on future production. The lack of transport facilities for energy exports, foreign market developments and investment conditions are more likely constraints. Although such factors will not necessarily determine how much can be produced, they are likely to have an impact on how rapidly production takes place.

Azerbaijan

IEA supply scenarios for Azerbaijan are based on an analysis of government forecasts and development plans of the major foreign investment projects, including those in Table 1. (This table was compiled from various sources, including press reports, and may in some cases reflect incomplete information.)

The sum of reported estimated reserves for individual projects comes to 1,800 - 2,400 Mt (13 - 18 billion barrels) of oil and condensate, and 1,200 - 1,300 Bcm (7.2 - 7.7 billion barrels of oil equivalent) of gas. These figures are considerably higher than most aggregated western estimates for Azeri recoverable reserves.

The cumulative peak production of all individual projects listed would be about 150 Mt (3.0 Mb/d) for oil and condensate, and 43 Bcm (0.7 Mtoe/d) for gas. However, these numbers are theoretical, since the projects listed will not necessarily have a common peak period. Moreover, some projects will be delayed, while others may advance more quickly than originally foreseen. It is assumed for the high oil production scenario that output by 2020 will be 80% of the theoretical figure for accumulated peak production of the major projects signed by 1998, i.e., 120 Mt (2.4 Mb/d). For 2010 a level of 70 Mt (1.4 Mb/d) was chosen.[1]

Projects not listed in Table 1 include those to enhance onshore oil production. An estimated 1 billion barrels of oil is still considered recoverable onshore with improved recovery techniques, although the remaining lifetimes of these fields will probably not reach much beyond 2010. An estimated peak onshore production of 10 Mt per year (0.2 Mb/d) in 2010 was incorporated into the scenarios.

Information available on individual projects is scant regarding associated gas production. Past ratios for Azeri oil and gas production refer to much smaller shares of offshore production (where the

1. PlanEcon figures are somewhat higher at 133 Mt (2.65 Mb/d) for 2020 and 87 mt (1.73 Mb/d) for 2010. Estimates from NefteCompass and Petroconsultants at around 45 Mt (0.9 Mb/d) for 2010 and 90 Mt (1.8 Mb/d) for 2020, are close to the IEA's low scenario.

Table 1 Azerbaijan: selected oil and gas projects

Project[1]	Est. production period (and est. peak)	Est. peak production (kboe/d)	Projected investment[2] (US$ billion)	Implied capital cost per boe/day of peak production capacity (US$)
AIOC	1998-2028 (2010-2020)	800 (oil) 50 (gas)	13	16,200
Apsheron	2005-2035 (2015-2025)	500 (oil) 330 (gas)	8	11,000
BP Exploration - Shakh Deniz	2003-2033 2015-2025)	400 (oil) 100 (gas)	3 - 4	6,000 - 8,000
CIPCO	2003-2032 (2011-2020)	200 (oil)	1.5 - 3	7,500 - 15,000
Elf - Lenkoran	2006-2036 (2011-2020)	300 (oil)	1.5 - 2	5,000 - 6,700
Lukoil- Yalama	2002-2032 (2012-2016)	110 (oil)	2	18,200
NAOC	2003-2033 (2010-2020)	140 (oil)	1.5 - 2.5	10,700 - 17,800
Mobil - Oguz		60 (oil)	1.8	18,000
Exxon - Nakhichivan		180 (oil) 80 (gas)	2 - 2.5	[11,000 - 14,000]
Amoco - Inam		200 (oil)	1.5 - 2.5	[7,500 - 12,500]
JNOC		140 (oil)	[2]	[14,200]
Total[3]		**3,000 (oil) 700 (gas)**	**39.8 - 46.3**	**10,700 - 12,500 (av.)**

Sources: various, including Petroconsultants, EIG, Interfax, Neftecompass and Russian Petroleum Investor. Figures in brackets are IEA estimates.
([1]) For descriptions of these and other projects, see the Investment section of the Azerbaijan chapter.
([2]) Undiscounted cumulative capital expenditure excluding operating costs, bonuses, debt take overs, social investments and pipeline investments.
([3]) Includes projects not listed.

amount of associated gas for a particular level of oil production is higher than it is onshore) and include onshore non-associated gas, which now appears exhausted. Moreover, the greater the volume of oil production, the less likely it will be that all associated gas produced will be able to be marketed. The ratio of marketed associated gas to oil production is therefore assumed to decline.

In the high scenario, gas production in 2010 is forecasted at 24 Bcm, and at 30 Bcm in 2020. For the low scenario, the same decline in the oil-to-gas ratio has been assumed, leading to a forecast of 15 Bcm in 2010 and 24 Bcm in 2020.

The total of all project values listed in Table 1 is US$ 40 - 46 billion. The average cost per barrel of oil equivalent of peak production capacity per day (for oil, condensate and gas) is US$ 10,700 - 12,500 per boe/day. This figure is lower than that for the North Sea, though at about the same level as for onshore projects in Kazakstan. It is also comparable to costs for onshore projects in Nigeria, Indonesia and Algeria.[2]

Kazakstan

Data in Table 2 were compiled in a fashion similar to those in Table 1. Reserves covered by estimated capital outlays presently add up to 23 - 24 billion barrels of oil and to 11 - 13 billion barrels of oil equivalent of gas. As in the case of Azerbaijan, this is greater than most aggregated outside reserve estimates.

The theoretical production rate for oil and condensate if all listed projects peaked together is 210 - 220 Mt per year (4.2 - 4.4 Mb/d). Similar to the calculations made for Azerbaijan, it was estimated that actual peak production, sometime between 2010 and 2020, will be 20% less. Total production in 2020 is estimated at 160 Mt (3.2 Mb/d) in the high scenario. In 2010, when several of the smaller projects will have reached their peak, annual production is expected to be 100 Mt (2 Mb/d).

While in Azerbaijan's high scenario, domestic use of oil is assumed to be 21% of total output in 2010 and 22% in 2020 (see section on methodology, below), in Kazakstan the shares are expected to be much higher (46% in 2010 and 53% in 2020). This is due to that country's larger domestic market. This implies that Kazak projects will be somewhat less affected by export constraints than those in Azerbaijan. The gap between high and low scenarios is therefore somewhat narrower for Kazakstan than for Azerbaijan. The low case oil production level for 2010 is 75 Mt (1.5 Mb/d) and 130 Mt (2.6 Mb/d) for 2020.

Theoretical cumulative peak production for gas is 67 Bcm (1.1 Mtoe/d). However, the peak in gas output is unlikely to be reached prior to 2020. This is because Kazakstan's gas production is largely independent of its oil output[3]. Future gas output will thus depend on special gas projects such as Karachaganak. However, a second major project of this kind is not yet in sight. Moreover, many of the promising development areas are far from consumption centres and export facilities.

The Karachaganak field is expected to reach its peak of 24 Bcm per year early in the new century. Given the low level of present production, the field should help the country's gas output grow at a higher rate than that of oil through 2020. Thereafter, gas output could stagnate. In the high scenario, the IEA predicts gas production of 29 Bcm in 2010, and 34 Bcm in 2020. In the low scenario, the IEA forecasts an output of 15 Bcm in 2010 and 20 Bcm in 2020.

Total capital outlays for current projects are forecast at US$64 - 79 billion. More than for Azerbaijan, there is a great variety across projects in Kazakstan regarding the unit cost indicator, "estimated capital cost per boe/day of peak production". (See Tables 1 and 2.) Despite the data uncertainties mentioned earlier, it would appear that the smaller onshore projects (in particular the workovers) will cost less per unit of capacity than most larger projects.

2 The cheapest capacity extensions onshore can be found in Iraq (US$ 1,000 per b/d of peak capacity), in Kuwait (US$ 3,000) and in Saudi Arabia (US$ 4,000).

3. Oil production in Kazakstan generally yields much less associated gas than it does in Azerbaijan. Since 1990 Kazakstan's oil production has been three times that of Azerbaijan, while gas output in both has been similar. Only one third of Kazakstan's gas output 1997 was associated, much of it from the Tengiz and Zhanazol fields. Most of the country's unassociated gas was produced at the Karachaganak field, which holds almost half of the country's proven reserves.

Table 2 Kazakstan: selected oil and gas projects

Project[1]	**Est. production period (and est. peak)**	**Est. peak production (kboe/d)**	**Projected investment[2] (US$ billion)**	**Implied capital cost per boe/day of peak production capacity (US$)**
Tengizchevroil	1996-2036 (2010-2020)	1,000 (oil) 500 (gas)	20 - 25	13,300 - 16,600
OKIOC	2004-2034 (2013-2023)	1,200 (oil)	20 - 23	16,600 - 19,000
Karachaganak	1995-2035 (2003-2023) 400 (gas)	300 (oil)	7 - 10	10,000 - 14,300
Kazakturkmunai	1997-2027 200 (gas)	600 (oil)	[6]	[7,500]
Japan JIT Oil	1998-2028	300 (oil)	3.87	[12,900]
Uzenmunaigaz (CNPC)	1965-2010 (2000)	160 - 320 (oil)	1.2	3,800 - 7,500
Aktobemunaigas (CNPC)		100 (oil)	0.5	5,000
Arman JV	1995-2025	100 (oil)	0.1	10,000
Tulparmunai JV		100 (oil)	2	[10,000]
Mangistaumunaigas	1980-2010 (2002-2006)	200 (oil)	2 - 4.1	10,000 - 20,000
Total[3]		**4,200-4,400 (oil) 1,100 (gas)**	**64 - 79**	**12,000 - 14,300 (av.)**

Sources: various, including Petroconsultants, EIG, Interfax, Neftecompass and Russian Petroleum Investor. Figures in brackets are IEA estimates.

([1]) For descriptions of these and other projects, see the Investment section of the Kazakstan chapter.
([2]) Undiscounted cumulative capital expenditure excluding operating expenditure, bonuses, debt take overs, social investments and pipeline investments.
([3]) Includes projects not listed.

Turkmenistan

In Turkmenistan there are no large foreign equity investment projects for oil and gas production. For the foreseeable future, oil production will probably be determined for the most part by government plans and by the financial constraints of the state budget. The high scenario for oil output reflects present government plans for 2000 of 10 Mt and IEA extrapolations of 12 Mt by 2010 and 14 Mt by 2020. Such a scenario would open up the possibility of modest oil exports around 2000.

Turkmenistan's offshore reserves are uncertain, not only from a geological point of view, but also in terms of access to export markets. These uncertainties have been factored into the above projections. In addition, the low case scenario assumes budget difficulties as a result of unsatisfactory gas exports through 2010. Annual oil production under this scenario would only be 7.0 Mt by 2010.

Gas output projections depend entirely on assumptions regarding export opportunities. As long as major new export pipelines are not in place, Turkmenistan's gas production and exports will continue to grow only sporadically, mirroring the payment abilities of its neighbours and its transit relationship with Russia. It is assumed that, at best, the part of its 80 Bcm per year capacity not currently in use would be revived by 2010. After 2010 one or more of the growing number of pipeline alternatives now under discussion are assumed to have materialised and additional production capacities built, allowing Turkmen gas production to take full advantage of existing reserves.[4] Assuming 3 Tcm of reserves lifted over 30 years yields an average annual production of 100 Bcm, which would be a reasonable production-to-reserve ratio by international standards. A peak annual production of at least 130 Bcm is assumed after the tenth year. The high scenario assumes production in 2010 to be 86 Bcm, reaching 130 Bcm by 2020.

The low scenario assumes transit or market difficulties. Problems in export markets are likely to have major implications on Turkmen shipments, with possible abrupt and substantial cuts. However, such cuts may not have a large impact on averaged output over a time period such as ten years. It is therefore appropriate to view the projection figures shown in in Tables 3-6 as averages for surrounding years, with a relatively small difference of 10% assumed between the high and low output scenarios for 2010 and 2020.

Uzbekistan

As mentioned earlier, Uzbekistan is nearly energy self-sufficient, though not a significant energy exporter. Therefore, uncertainties regarding export possibilities will not be as important as they are for Turkmenistan. The official government goal of 12 Mt of annual oil production by 2010 and 14 Mt by 2020 appears feasible, as does the goal for 63 Bcm of gas production by 2010. For the low scenario, a reduction of 10% in oil and gas production for 2010 and 2020 was assumed, reflecting technical and other delays rather than demand constraints for the small amounts available for export.

DOMESTIC DEMAND AND EXPORTS

Summary

For each country a high and a low GDP growth scenario was estimated and combined with the high and low supply scenarios respectively, leading to demand forecasts and consequent estimates of oil and gas available for export. Under the high scenario the four countries together would have an estimated exportable surplus of 117 Mt of oil in 2010 and 178 Mt in 2020, coupled with an exportable gas surplus of 84 Bcm in 2010 and 120 Bcm in 2020. The low case scenario calls for 75 Mt of exportable oil in 2010 and 148 Mt in 2020, with exportable gas surpluses of 72 Bcm in 2010 and 116 in 2020. (These projections are not net of energy trade between the four countries.)

4. Estimates vary between 2.7 trillion cubic metres (Tcm) of proven reserves made by Russian Gasprom and 15-21 Tcm of unspecified reserves made by the Turkmen authorities.

Table 3 Oil production, domestic consumption and net exports (high case) (Mt)

	1990	1995	2000	2005	2010	2020
Kazakstan						
production	25.2	20.5	45.0	70.0	100.0	160.0
consumption	27.2	10.4	20.0	33.7	45.5	84.2
net exports	– 2.0	10.1	25.0	36.3	54.5	75.8
Azerbaijan						
production	12.3	9.2	14.0	30.0	70.0	120.0
consumption	8.6	7.0	10.2	13.0	15.0	25.9
net exports	3.7	2.2	3.8	17.0	55.0	94.1
Turkmenistan						
production	3.4	3.5	10.0	11.0	12.0	14.0
consumption	4.8	5.7	7.0	7.0	7.0	8.0
net exports	– 1.4	– 2.2	3.0	4.0	5.0	6.0
Uzbekistan						
production	2.8	7.6	10.0	11.0	12.0	14.0
consumption	10.2	8.6	8.7	9.0	10.0	12.0
net exports	– 7.4	– 1.0	1.3	2.0	2.0	2.0
Total						
production	43.7	40.8	79.0	122.0	194.0	308.0
consumption	50.9	31.7	45.9	65.6	77.5	130.1
net exports	– 7.1	9.1	33.1	56.4	116.5	177.9

Table 4 Oil production, domestic consumption and net exports (low case) (Mt)

	1990	1995	2000	2005	2010	2020
Kazakstan						
production	25.2	20.5	40.0	55.0	75.0	130.0
consumption	27.2	10.4	15.6	24.4	31.6	51.9
net exports	– 2.0	10.1	24.4	30.6	43.4	78.1
Azerbaijan						
production	12.3	9.2	14.0	25.0	45.0	90.0
consumption	8.6	7.0	10.2	12.9	14.8	21.9
net exports	3.7	2.2	3.8	12.1	30.2	68.1
Turkmenistan						
production	3.4	3.5	6.0	6.5	7.0	8.0
consumption	4.8	5.7	6.0	6.5	7.0	8.0
net exports	– 1.4	– 2.2	0.0	0.0	0.0	0.0
Uzbekistan						
production	2.8	7.6	9.0	10.0	11.0	13.0
consumption	10.2	8.6	8.7	9.0	9.5	11.0
net exports	– 7.4	– 1.0	0.3	1.0	1.5	2.0
Total						
production	43.7	40.8	69.0	96.5	138.0	241.0
consumption	50.9	31.7	40.4	52.8	62.9	92.8
net exports	– 7.1	9.1	28.6	43.7	75.1	148.2

Table 5 Gas production, domestic consumption and net exports (high case) (Bcm)

	1990	1995	2000	2005	2010	2020
Kazakstan						
production	7.0	5.9	9.8	14.7	29.4	34.3
consumption	14.7	12.5	14.7	18.4	29.4	34.3
net exports	– 7.7	– 6.6	– 4.9	– 3.7	0.0	0.0
Azerbaijan						
production	9.9	6.7	7.4	17.3	23.5	29.6
consumption	13.6	7.3	7.4	9.7	12.1	19.8
net exports	– 3.7	– 0.6	0.0	7.6	11.4	9.9
Turkmenistan						
production	84.3	35.6	42.9	61.2	85.7	129.8
consumption	14.5	9.8	9.4	11.3	13.8	18.7
net exports	69.7	25.8	33.5	50.0	71.9	111.1
Uzbekistan						
production	40.4	48.6	51.4	56.3	62.5	73.5
consumption	37.6	44.2	49.4	55.9	61.6	74.4
net exports	2.8	4.4	2.0	0.4	0.8	– 0.9
Total						
production	141.6	96.8	111.5	149.5	201.0	267.2
consumption	80.5	73.8	80.9	95.2	117.1	147.2
net exports	61.1	23.0	30.6	54.3	84.0	120.0

Table 6 Gas production, domestic consumption and net exports (low case) (Bcm)

	1990	1995	2000	2005	2010	2020
Kazakstan						
production	7.0	5.9	8.0	12.2	14.7	19.6
consumption	14.7	12.5	12.9	15.9	17.1	19.6
net exports	– 7.7	– 6.6	– 4.9	– 3.7	– 2.4	0.0
Azerbaijan						
production	9.9	6.7	7.4	11.1	14.8	23.5
consumption	13.6	7.3	7.4	8.6	9.9	16.0
net exports	– 3.7	– 0.6	0.0	2.5	4.9	7.4
Turkmenistan						
production	84.3	35.6	36.7	49.0	75.9	117.6
consumption	14.5	9.8	9.6	10.2	12.0	15.4
net exports	69.7	25.8	27.2	38.8	63.9	102.2
Uzbekistan						
production	40.4	48.6	50.2	53.9	58.8	67.4
consumption	37.6	44.2	46.8	50.9	53.6	61.0
net exports	2.8	4.4	3.5	3.0	5.1	6.3
Total						
production	141.6	96.8	102.3	126.2	164.2	228.0
consumption	80.5	73.8	76.6	85.7	92.7	112.1
net exports	61.1	23.0	25.7	40.6	71.6	115.9

The largest gap between the high and low scenarios is for oil exports in 2010, reflecting uncertainties on the timing of large projects presently under preparation in Azerbaijan and Kazakstan. In potential major oil and gas exporting countries such as these, production will probably depend more on finance and export opportunities than on the full success of internal economic reforms. However, the latter can speed up the process considerably by attracting additional domestic and foreign funds and promoting the timely installation of infrastructure necessary for oil and gas development. While the higher GDP growth generated by intensified reforms will entail more domestic energy use, the incremental amounts of consumption are assumed to be less than the additional energy exports made possible through increased production.

Providing that certain minimum investment conditions are met, foreign oil and gas companies can engage themselves in most countries, though with investments on a lower scale and at a slower pace than in more economically liberalised ones. A slower pace of investment will in turn provide slower GDP growth. Although lower economic growth requires less use of energy in the domestic economy, leaving more for exports, the resulting lower energy production will tend to outweigh the effects of reduced domestic demand on the amount of energy available for exports.

Among the four countries under review, only in Uzbekistan is the degree of economic reforms likely to have less impact on the level of energy supply than on the level of energy use. There the low scenario is expected to actually free up more gas for export than would the high scenario, which would lead to greater domestic consumption.

The energy sector is usually one of the most energy intensive industries in an economy. Over the next 12 years its share in total GDP under the high case is expected to almost double for Azerbaijan (from 15% to almost 27%), and triple for Turkmenistan (from 10% to 29%). Half of these gains in GDP shares are attributed to larger output volumes, with the rest to future rises in relative domestic energy prices. The volume-based part of the structural change in GDP will work against a fast decrease of energy intensity in these two economies even if market incentives for higher energy efficiency are in place.

The Central Asian and Transcaucasian countries are sometimes compared with oil exporters in the Persian Gulf and North Sea. However, important differences should be noted. In terms of the criteria assembled in Tables 7-15 (in the statistical annex), the four countries under review are, and can be expected to remain, more similar to Russia than to Norway or Saudi Arabia, to which they are also compared.

Saudi Arabia's energy intensity has increased dramatically over the last 20 years, despite a decline in the importance of the energy sector. One reason for the higher energy intensity is a high annual population growth (4.9%) that exceeds by far annual GDP growth (1.9%), the latter of which has suffered from the steady decline in real oil prices. The other reason is that the decline of the energy sector's share of GDP (from 71% in 1975 to 42% in 1995) is due primarily to oil price developments and not to lower oil output. The rapid population growth and slow economic growth has almost halved income per head in Saudi Arabia, from US$11,130 in 1975 to US$6,419 in 1995. (The present level is what could be expected for Azerbaijan and Kazakstan by about 2020.)

Norway's oil-driven economic growth began in 1975 from a per capita income more than five times the present level of that in the Caspian area. Given the high economic development stage of Norway, its energy sector, despite a high production-to-consumption ratio, today accounts for only 15% of GDP. In statistical terms this greater degree of economic diversification is the result of a higher starting point at the beginning of the oil boom. But in real terms it is the result of efficient economic policies and market forces prior to 1975 that allowed this higher development level to be reached; and of their continuation after 1975, which permitted the economy to benefit fully from the oil boom.

Azerbaijan

Azerbaijan is expected to export some 4 Mt of oil in 2000 in both the high and low scenarios. By 2010 oil exports in the high case are forecast at 55 Mt and at 94 Mt by 2020. In the low case only 30 Mt would be exported by 2010 and 68 Mt by 2020.

Gas exports are expected around 2005. By 2010 they are projected to reach 5 - 11 Bcm, depending on the scenario.

Among the four countries, Azerbaijan s economy is expected to receive the greatest boost from the oil and gas sector, with higher GDP growth rates than in the other three. Up to 2010 annual GDP growth is expected to be 7% in the high case and 5.7% in the low case. Beyond 2010 economic growth is assumed to be somewhat less because of GDP levels already achieved and lower percentage increases in the assumed energy supply scenarios.

The energy sector's share in GDP in Azerbaijan is, at around 15%, the highest among the four countries covered by this study. Between 1995 and 2000 it is expected to grow, not only because of higher oil and gas output, but also due to more price deregulation on the internal market. More than half of the oil produced is expected to be exported by 2000. As this ratio rises, the share of crude oil sold abroad will increase and depress somewhat the value added per average tonne of crude produced. Nevertheless, by 2010 the share of the energy sector in GDP is projected to rise to 27% in both the high and low case scenarios.

The high case growth assumptions for the economy imply a sustained pace of economic reforms and considerable infrastructure development. Sectors such as transport and construction can be expected to benefit significantly from the energy boom and grow faster than GDP. Others, such as agriculture and public services, will probably experience much slower growth.

Kazakstan

The absolute amount of increased oil and gas production in Kazakstan will be greater than in Azerbaijan. However, given the larger size of the Kazak economy, increases in exports will probably be less for Kazakstan than for Azerbaijan. In the high scenario oil exports of 55 Mt are expected for 2010, and 76 Mt for 2020. In the low scenario projected exports are 43 Mt in 2010 and 78 Mt in 2020. For 2020 oil exports in the high and low scenario are almost identical.

Given the larger Kazak economy with a less important energy sector in relative terms, the same amount of additional oil production can be expected to have a relatively smaller affect on economic growth in Kazakstan than in Azerbaijan. Kazak GDP growth scenarios were therefore chosen with lower rates than those in Azerbaijan (5.5% and 3.5%, respectively, in the first decade and 5% and 3.8% in the second).

Domestic energy consumption in Kazakstan is greater than that in Azerbaijan, not only due to the larger size of the Kazak economy, but also due to Kazakstan's somewhat higher energy intensity, thanks mainly to the energy intensive basic metals industry.

Although Kazak net gas imports are assumed to cease in the future, significant net gas exports are not expected in the long term. It is assumed that additional power generating capacity will be fired with gas. While mine-mouth coal-fired power stations will continue to be operated, others requiring expensive long haul transportation of coal are expected to be eventually replaced by gas-fired plants. In the case of a gas glut in Central Asia, Turkmenistan is likely to be able to undercut the export prices of its smaller potential competitors such as Kazakstan and Uzbekistan, since these countries would probably not make large price concessions for gas exports as long as they have sufficient demand in their domestic economies.

In the long run, value added per unit of crude oil produced in Kazakstan is assumed to be higher than in Azerbaijan. A higher portion of crude production is expected to remain in the country and its value added upgraded through refining and distribution to end consumers.

Turkmenistan

Turkmenistan's potential energy exports could spur economic growth as strong as that expected for Azerbaijan. Turkmen gas exports are forecast to account for as much as 90% of the combined gas exports from the four countries. In the high case scenario they are estimated at 72 Bcm in 2010 and 111 Bcm in 2020. The low case scenario calls for 64 Bcm in 2010 and 102 Bcm in 2020. Oil exports would only exist for the high case scenario, at 5 Mt in 2010 and 6 Mt in 2020.

In addition to the large uncertainties linked to the availability of necessary new gas export pipelines, there is also uncertainty regarding the success of economic reforms, the lack of which could deter large-scale foreign investments in the energy sector for some time.

Notwithstanding current economic problems as a result of curtailed export opportunities, the long term economic growth rates assumed for the next ten years are significantly below those for the other three countries. They reflect an assumption that reforms will continue, but at a slower pace than in the others. Given Turkmenistan's lower economic growth conditions, its relatively less developed economy outside the energy sector, and possible large increases in gas exports, the already important role held by the energy sector in the Turkmen economy is likely to increase. The energy sector's size relative to that of the domestic economy as a whole would exceed widely that of the Azeri energy sector if domestic and, in particular, export prices for gas reach internationally comparable levels. However, this seems to be unlikely given that Turkmenistan appears inclined to continue heavy subsidisation of domestic gas prices. More importantly, it may be obliged to make significant price concessions to its export clients in order to be paid at all. Given the current pricing situation, incentives for energy savings in Turkmenistan are assumed to be less than those in the other three countries.

Uzbekistan

As mentioned earlier, Uzbekistan is the only one of the four countries whose economic growth will not be driven primarily by energy exports. Oil exports are expected to be only 2 Mt in both 2010 and 2020 in the high scenario. Gas exports would be the small difference between domestic production and consumption and could vary strongly over time, depending more on economic growth rates than on gas production. In the high case they are expected to drop to zero and to become negative by 2020. In the low case 5 Bcm would be exported in 2010 and 6 Bcm in 2020.

Given its large population, Uzbekistan will not be able to count on large energy exports as an engine for economic growth. It seems unlikely that economic reforms will be able to induce the oil driven growth rates expected for Azerbaijan and Kazakstan. With GDP growth rate assumptions of 4.5% in the high case and 3.0% in the low case for the period 2000 to 2020, Uzbekistan ranks third among the four countries.

The supply side scenarios call for the energy sector to grow less than GDP. In the high and low cases, energy output is expected to grow 2.0% and 1.8% per year, respectively. These scenarios assume a considerable reduction of energy intensity in the economy. Uzbekistan has liberalised its energy prices more thoroughly than Turkmenistan has, though not as much as Azerbaijan or Kazakstan.

Value added per unit of oil and gas produced is higher in Uzbekistan than it is in the other three countries. Almost all energy produced is used domestically in the form of processed products with high value added. As opposed to the situation in the other three countries, no changes in value added per unit of output therefore are expected over time, barring changes in the international prices of oil and gas.

NOTES ON METHODOLOGY

Energy demand estimates

Energy demand in the scenarios is estimated using a "bottom-up" approach. Various indicators are estimated for energy-using activities and multiplied by estimates of energy consumption per unit of activity to yield energy consumption for those activities and, in aggregate form, for the economy as a whole. The energy-using activities are grouped into three categories: "energy", "non-energy industry" and "non-industry".

Energy

Oil refining requires refinery fuel; gas production and distribution needs gas for compressors in pipelines; and electricity and heat generation requires primary energy inputs. Activity indicators for primary energy industries are the production volumes for oil, gas and coal from the supply scenarios, while the volume of heat and electricity produced was derived as a function of GDP estimates. For each of these energy production activities expressed in physical units, a specific primary energy consumption per unit of output was estimated in tonnes of oil equivalent (toe), using historic data for the four countries and for Russia as benchmarks.

"Non- energy industry" and "non-industry"

"Non-energy industry" includes manufacturing and construction. "Non-industry" is composed mainly of agriculture, transport, and commercial and public services. For these two broad economic sectors, the activity indicator was value added in 1993 US dollars of output. It was multiplied with estimates of energy use per thousand 1993 US dollars. Both kinds of estimates were made for the years 1990 to 1995 using historic energy and GDP statistics as available for the four countries and for Russia.

Estimates of future value added of the two sectors were also made. Projected GDP in constant US dollars was derived on the basis of growth rate assumptions discussed for each country above. Value added of the energy sector was obtained by multiplying the physical unit data for the supply scenarios with estimates of expected value added per unit of fuel output (oil, gas, coal, electricity).

Energy prices are the main determinant for value added per unit of output in the energy sector. Since the early 1990s, real domestic and export prices for energy have risen substantially for the four countries covered in this study. Further rises are possible for specific fuels and countries. The assumptions made on the evolution of value added per unit of energy output are shown in the data block, "Value added per unit of output under current energy prices" in the various country tables in the statistical annex.

The estimated value added levels of the energy sector were computed as percentages of GDP. An estimate of the evolution of the share of net indirect taxes was made based on assumptions on future fiscal policies. In a final step an estimate was made of the split of the remaining residual share in GDP of the "non-energy industry" and "non-industry" sectors.

For energy export-driven economies such as Azerbaijan and Turkmenistan, non-energy industry sectors such as manufacturing and construction are likely to grow faster than non-industry. This means that the share of non-energy industry in GDP will be maintained or only drop slightly, while the share of non-industry will show a greater decline in relative importance. Of course, not all subsectors of non-industry will lose GDP shares. Some, such as transport and commercial services, may maintain or even increase their shares. But others, such as agriculture and public services, are likely to grow much more slowly.

When peak oil and gas output is approached and production growth rates begin to decline, the secondary effects of the oil and gas boom may actually drive the growth rates of non-energy industry higher than that of the energy industry. Value added shares and levels for the two non-energy sectors were estimated with such considerations in mind. Combined with estimates for shares of the energy sector and of net indirect taxes, they provide a projection of structural changes in GDP. Data on GDP shares at current energy prices may be found in Table 9 in the statistical annex. They allow useful comparisons with structural changes over past periods in countries such as Russia, Norway and Saudi Arabia. They also permit an assessment of the plausibility of assumed GDP growth rates. Under a given absolute size of the energy sector in terms of value added, and assuming reasonable shares of non-energy industries, a plausible GDP growth rate follows.

In a GDP structure under current energy prices, the share estimates of the non-energy sectors would be biased downward if energy prices increased. The growing share of the energy sector would then also be due to energy price increases and not only to increases in output. Only an energy sector share given under constant energy prices allows one to see a residual share for the other two sectors which is not influenced by higher energy prices. This second set of GDP structure data is shown under the heading, "GDP shares at constant energy prices" in the tables of economic and energy indicators in the statistical annex. Shares are estimated in a fashion similar to those under current energy prices. However, instead of using value added estimates per unit of energy output at current prices, it employs the set of data labelled, "value added per unit of (energy) output at constant energy prices".

The shares obtained in this second set of GDP structure assumptions are used to estimate energy consumption in the two non-energy sectors on the basis of estimates for specific energy consumption per thousand US dollars of value added in 1993 dollars.

Activities in the household sector

The household sector is the only one that consumes energy without having a value added share in GDP. In both scenarios, estimates of future population levels from World Bank sources are used as an activity indicator for the household sector. Two series of specific energy consumption per capita are estimated: private petrol use in cars and residential energy use. Each series is multiplied by the projected population level, with the sum of both results leading to an estimate of total primary energy consumption by households.

Energy export estimates

Projected net exports were derived as the difference between projected total primary energy supply and total primary energy demand in the domestic economy. Their split into oil, gas and coal exports (including derived products) was done on a judgmental basis. Major assumptions for the split were that future domestic power and heat production would be primarily based on coal and gas, and that oil exports would be preferable to gas exports in cases where gas prices at the border were likely to be lower than equivalent oil export prices.

Specific assumptions and data biases

Losses

Generally, the amount of energy consumption and losses in the oil, gas and coal sub-sectors was estimated conservatively at 6% for oil and coal, and 8% for gas. This includes losses in the field, in transport and in processing. For oil, processing accounts for the greatest portion of the loss, since refining losses for exported crude do not apply. The average oil loss was assumed to be only 5% for Azerbaijan's and Kazakstan's oil exports, most of which is expected to consist of crude. Most gas losses occur in transport. For part of the Kazak gas pipeline system a loss rate of as high as of 11% has been reported, due to leaks from worn out pipes. The assumed average loss of 8% for all four countries compares to 4.5% on average in OECD countries. The loss rate in gas pipelines is forecast to improve after 2010 to only 6% when an increasing part of the system is expected to consist of new pipes.

Heat and electricity demand

For developing economies it has been fairly well established that electricity demand grows faster than GDP even with market incentives to save energy. The transition economies of the FSU are not expected to be in that situation until 2010; up to 2000 their electricity demand is expected to grow less than GDP. In the short term, as non payment problems are overcome by stricter penalties, and as real electricity prices increase, there will be more incentives to save electricity than in the past. Moreover, during the economic decline of the early 1990s, electricity consumption proved to be very inelastic with respect to GDP due to a certain amount of overhead use in industry and households that did not depend on industrial output levels. This inelasticity is expected to continue during the first few years of economic recovery when, due to fixed overhead consumption, economic output should rise more quickly than total electricity use. It is estimated that by 2000 overhead consumption will have been absorbed and payment discipline and electricity prices stabilised. Between 2000 and 2010 it is assumed that electricity demand and production will grow at the rate of GDP. Efficiency in electricity use may still increase, though at the same time the substantial electricity consumption in the fast growing oil and gas sector can be expected to increase at a greater rate than that for GDP. Moreover, household consumption increases may exceed GDP growth, due to a faster increase in the standard of living. The elasticity of electricity consumption with respect to GDP is assumed to be 1.03 between 2010 and 2015, and 1.02 between 2015 and 2020. With the modernisation of the industrial economy, a number of processes using primary energy are expected to be replaced with those using electricity, for example in the steel industry. Faced with rising wage bills, it is also expected that industry will tend to substitute labour with electrically driven equipment.

It is assumed that commercial heat will be produced only in conjunction with electricity, while heat from separate boiler houses is considered part of primary energy use by households. This means that the more heat produced together with electricity, the higher the primary energy use per kWh generated. For the Russian power and heat system the average input per TWh produced was 0.32 Mtoe in 1990, and 0.35 Mtoe in 1995, of which two thirds were for electricity production and one third for heat. For the four countries under consideration, the share of combined heat and power in the overall system is assumed to be somewhat less; an initial specific consumption of 0.3 Mtoe/TWh is assumed. After 2000 the rate is expected to decline as a result of more efficient fuel management and technologies and also as a result of older CPH units being phased out and replaced by modern combined cycle gas turbines.

Value added per unit of energy output

As mentioned earlier, two sets of GDP share structures were used; one at current energy prices and one at constant energy prices. The latter is not only useful for estimating energy consumption in certain non-energy sectors, it also can be seen as a corrected estimate of the energy share at current energy prices. Since tax collection has become stricter, output levels of firms are no longer over-reported, as in the Soviet era, but instead may even be under-reported. It is estimated that the unofficial economy in some FSU countries is as much as 50% of the size of officially reported GDP. Energy sector output is more difficult to dissimulate than that of other sectors; its share in official unadjusted GDP figures therefore tends to be overstated. However, if it is adjusted for the energy price rises of recent years, the result may be closer to its true share in the economy than the one based on current energy prices.

Net indirect taxes

A fairly important aspect of the structure of future GDP at market prices is the expected change in the share of net indirect taxes, i.e., gross indirect taxes minus price subsidies. Such changes can have the same effect as relative price changes. For the purpose of estimating energy consumption of GDP sectors, the use of GDP at factor cost would probably be more appropriate. However, in the present context the necessary adjustments would complicate the simple overall approach while contributing little to the precision of energy consumption estimates in the two non-energy sectors.

The historic changes of net indirect taxes in GDP at market prices are of certain interest for energy sector analysis. A large portion of indirect taxes and price subsidies in an economy in transition are usually linked to energy. As subsidies are phased out over time and a value added tax implemented on western European levels, the share of net indirect taxes in GDP should increase and eventually reach 10% or higher. (Norway's share is presently around 11%.) The evolution of net indirect taxes over the period 1990 to 1995 in the four countries under review gives some indications of how far price subsidies have been abolished and/or indirect taxes raised. In Azerbaijan and Turkmenistan the share actually came down from around 6% in 1990 to 2% in 1995, indicating a higher level of subsidies and/or lower level of indirect taxes. In Kazakstan it rose from negative values (net subsidies) in 1990 to 5% in 1995, and in Uzbekistan from negative values in 1990 to 10% in 1995. For the other three countries the share is expected to reach 10% by 2020 at the latest.

Energy use per unit of value added in non-energy industry

Evidence from Russian and Saudi Arabian data show that the energy intensity in non-energy industry is higher than in the non-industry sector of GDP. More important than the rather uncertain differences in level is the difference in price elasticities. Primary energy demand by non-energy industry is more price elastic than that by non-industry, much of which does not operate under competitive market conditions. Incentives and possibilities to reduce energy consumption in the non-industry part of the economy are therefore modest. These considerations have been incorporated into the projected energy intensities, as shown in Table 12.

Households

For the period 1990-1995, petrol for road transport is one of the few consumption statistics available for each of the four countries. It is assumed that 20-25% of petrol in the four was used for private purposes in the early 1990s, and up to 50% in 1995. That assumption results in a gradual increase of per capita use over the period 1990-1995, a trend that is expected to continue. Per capita use of petrol for private purposes in physical units is assumed to double over the next 25 years.

Primary energy use in households (including heat from boiler stations) is assumed to have been around 0.4 Mtoe per head over the period 1990 to 1995. (For comparison, the figure for Russia is 0.6 Mtoe.) A certain amount of energy savings is likely to occur as energy prices rise and as the non-payment problem is resolved, thus creating incentives for greater energy efficiency in households. At the same time, the higher income per head will probably induce households to achieve a higher housing standard in terms of square metres per person. It is also likely to increase the use of heat. As it is difficult to estimate which of the two counteracting factors will be stronger, the specific energy consumption per head has been kept constant over the forecasting period.

STATISTICAL ANNEX

Table 7 Annual GDP growth (high case) (%)

	1990	1995	2000	2005	2010	2020
Azerbaijan		– 16.0	7.0	7.0	7.0	6.2
Kazakstan		– 8.9	4.4	5.5	5.5	5.0
Turkmenistan		– 8.0	1.0	3.0	3.0	4.0
Uzbekistan		– 3.9	3.0	4.5	4.5	4.5
Russia		– 9.1				
Norway	3.2	3.5				
Saudi Arabia	1.9	5.7				

Table 8 Annual GDP growth (low case) (%)

	2000	2005	2010	2020
Azerbaijan	7.0	6.0	5.5	5.0
Kazakstan	3.5	3.5	3.5	3.8
Turkmenistan	0.0	2.0	2.5	3.0
Uzbekistan	2.0	3.0	3.0	3.0

Table 9 Energy sector share of GDP at current energy prices (high case) (%)

	1975	1990	1995	2000	2005	2010	2020
Azerbaijan		5.1	14.6	16.2	22.1	29.5	26.8
Kazakstan		7.2	10.1	14.6	17.1	18.4	17.5
Turkmenistan		9.6	10.2	17.9	22.7	25.8	29.3
Uzbekistan		4.1	11.1	11.7	10.8	9.4	7.5
Russia		8.3	12.0				
Norway	4.5	13.0	14.9				
Saudi Arabia	71.2	41.0	41.7				

Table 10 Energy sector share of GDP at current energy prices (low case) (%)

	2000	2005	2010	2020
Azerbaijan	16.2	19.0	22.9	26.7
Kazakstan	14.1	16.0	17.4	19.3
Turkmenistan	14.2	17.7	22.6	29.7
Uzbekistan	11.9	11.3	10.8	9.8

Table 11 Energy sector share of energy demand (high case) (%)

	1990	1995	2000	2005	2010	2020
Azerbaijan	41.4	39.5	37.5	42.1	42.6	50.6
Kazakstan	34.5	37.2	35.0	36.4	37.1	38.9
Turkmenistan	53.8	39.6	42.6	47.1	48.6	50.3
Uzbekistan	41.1	33.5	32.0	31.8	30.1	26.4
Russia	41.6	46.1				
Norway	23.9	28.0				

Table 12 Energy intensity (high case) (toe per 1993 US$ thousand of GDP)

	1975	1990	1995	2000	2005	2010	2020
Azerbaijan		0.72	1.14	1.02	0.93	0.79	0.73
Kazakstan		1.17	1.18	1.13	1.06	0.98	0.85
Turkmenistan		1.01	1.11	1.13	1.11	1.05	0.91
Uzbekistan		0.70	0.91	0.86	0.78	0.67	0.52
Russia		0.84	1.00				
Norway	0.23	0.20	0.19				
Saudi Arabia	0.13	0.59	0.70				

Table 13 Energy use per head (high case) (toe per capita)

	1975	1990	1995	2000	2005	2010	2020
Azerbaijan		2.7	1.9	2.1	2.5	2.8	4.3
Kazakstan		5.1	3.5	3.8	4.4	5.2	6.8
Turkmenistan		5.2	3.1	2.8	2.8	2.9	3.2
Uzbekistan		2.1	2.1	2.0	2.0	2.0	2.1
Russia		6.1	4.5				
Norway	3.8	5.1	5.5				
Saudi Arabia	1.5	4.2	4.5				

Table 14 Income per head (high case) (1993 US$)

	1975	1990	1995	2000	2005	2010	2020
Azerbaijan		3792	1518	2024	2702	3574	5945
Kazakstan		4457	2806	3376	4163	5327	8007
Turkmenistan		5194	2733	2467	2496	2710	3494
Uzbekistan		3089	2274	2323	2564	2986	3977
Russia		7214	4453				
Norway	16655	25210	29497				
Saudi Arabia	11130	7206	6419				

Table 15 Ratio of energy production to energy consumption (high case)

	1975	1990	1995	2000	2005	2010	2020
Azerbaijan		1.06	1.04	1.23	2.11	3.60	3.43
Kazakstan		1.05	1.12	1.31	1.42	1.55	1.55
Turkmenistan		3.97	2.36	3.07	3.77	4.48	5.15
Uzbekistan		0.89	1.05	1.06	1.04	1.04	1.02
Russia		1.42	1.45				
Norway	1.10	5.60	7.69				
Saudi Arabia	34.47	5.82	5.68				

Table 16 Azerbaijan: summary of high and low scenarios

	1990	1995	2000	2005	2010	2020
Population (million)	7.2	7.5	7.9	8.3	8.8	9.7
GDP (1993 US$ billion)						
high case	27.3	11.4	16.0	22.4	31.5	57.7
low case			16.0	21.4	27.3	44.5
Oil production (Mt)						
high case	12.3	9.2	14.0	30.0	70.0	120.0
low case			14.0	25.0	45.0	90.0
Gas production (Bcm)						
high case	9.9	6.7	7.4	17.3	23.5	29.6
low case			7.4	11.1	14.8	23.5
Oil consumption (Mt)						
high case	8.6	7.0	10.2	13.0	15.0	25.9
low case			10.2	12.9	14.8	21.9
Gas consumption (Bcm)						
high case	13.6	7.3	7.4	9.6	12.0	19.8
low case			7.4	8.6	9.9	16.0
Oil exports (Mt)						
high case	3.7	2.2	3.8	17.0	55.0	94.1
low case			3.8	12.1	30.2	68.1
Gas exports (Bcm)						
high case	– 3.7	– 0.6	0.0	7.7	11.5	9.9
low case			0.0	2.5	4.9	7.4

Table 17 Azerbaijan: economic and energy indicators (high case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	7.2	7.2	7.3	7.4	7.5	7.5	7.9	8.3	8.8	9.2	9.7
GDP (US$ billion)	27.3	27.1	21.0	16.1	13.0	11.4	16.0	22.4	31.5	43.1	57.7
Annual GDP growth (%)	– 0.7	– 22.5	– 23.3	– 19.3	– 12.3	7.0	7.0	7.0	6.5	6.0	
GDP per capita (US$)	3791.7	3743.1	2864.9	2175.7	1742.6	1518.0	2023.9	2701.9	3574.2	4684.1	5945.2
GDP share at current energy prices %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	
Net indirect taxes	11.8	6.5	8.9	6.2	2.8	2.9	4.0	5.0	7.0	9.0	10.0
Industry	30.4	29.9	36.7	32.4	34.9	36.0	39.0	40.0	45.0	45.0	44.0
Energy industry	5.1	4.9	5.9	8.0	11.3	14.6	16.2	22.1	29.5	29.8	26.8
Oil prod., transport and refining	2.3	2.2	2.8	3.8	5.9	8.1	10.5	14.7	22.3	23.2	20.8
Gas prod., transport and refining	1.2	1.0	1.2	1.5	2.0	2.8	2.4	4.4	4.2	3.6	2.9
Electricity and heat prod. and distrib.	1.7	1.7	1.9	2.6	3.4	3.7	3.3	3.1	3.0	3.0	3.1
Non-energy industry	25.3	25.0	30.8	24.4	23.6	21.4	22.8	17.9	15.5	15.2	17.2
Non-industry	57.8	63.6	54.4	61.4	62.3	61.1	57.0	55.0	48.0	46.0	46.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	80.0	100.0	120.0	110.0	100.0	100.0	100.0
Gas (US$/toe)	40.0	40.0	40.0	45.0	50.0	60.0	65.0	70.0	70.0	70.0	70.0
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.022	0.025	0.025	0.03	0.03	0.03	0.03	0.03
GDP share at constant energy prices (%)	100	100	100	100	100	100	100	100	100	100	
Net indirect taxes	11.8	6.5	8.9	6.2	2.8	2.9	4.0	5.0	7.0	9.0	10.0
Industry	30.4	29.9	36.7	32.4	34.9	36.0	37.0	38.0	41.0	41.0	40.0
Energy industry	5.1	4.9	5.9	6.9	8.0	8.9	8.1	11.2	15.5	15.7	14.1
Oil prod., transport and refining	2.3	2.2	2.8	3.2	3.7	4.0	4.4	6.7	11.1	11.6	10.4
Gas prod., transport and refining	1.2	1.0	1.2	1.4	1.6	1.9	1.5	2.5	2.4	2.0	1.7
Electricity and heat prod. and distr.	1.7	1.7	1.9	2.4	2.7	3.0	2.2	2.0	2.0	2.0	2.0
Non-energy industry	25.3	25.0	30.8	25.5	26.9	27.1	28.9	26.8	25.5	25.3	25.9
Non-industry	57.8	63.6	54.4	61.4	62.3	61.1	59.0	57.0	52.0	50.0	50.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Gas (US$/toe)	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Table 17 Azerbaijan: economic and energy indicators (high case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	20.4	19.0	18.2	16.0	15.0	14.7	20.1	44.1	89.1	122.1	144.1
Oil	12.3	11.8	11.6	10.3	9.6	9.2	14.0	30.0	70.0	100.0	120.0
Gas	8.0	7.0	6.4	5.5	5.2	5.4	6.0	14.0	19.0	22.0	24.0
Primary electricity	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Electricity production (TWh)											
Total	23.2	23.4	19.7	19.1	17.6	17.0	17.5	22.8	31.4	43.7	59.1
Thermal	22.5	21.6	17.9	16.7	15.8	15.4	16.0	21.3	29.9	42.2	57.6
Domestic primary energy use (Mtoe)											
Total observed	19.7	18.1	15.4	16.3	16.1	13.0					
Total computed	19.2	19.3	16.9	16.5	15.4	14.2	16.3	20.9	24.8	34.6	42.0
Oil prod., transport and refining	0.7	0.7	0.7	0.6	0.6	0.6	0.8	1.5	1.5	5.0	6.0
Gas prod., transport and refining	0.5	0.4	0.5	0.4	0.4	0.4	0.5	1.1	1.0	1.5	1.4
Electricity and heat prod. and distrib.	6.8	6.5	5.4	5.0	4.7	4.6	4.8	6.2	8.1	11.0	13.8
Non-energy industry	3.2	3.2	3.2	2.3	2.1	1.9	2.5	3.0	3.7	4.7	6.0
Productive non-industry	4.7	5.2	3.7	4.7	4.0	3.1	3.8	4.9	5.9	7.3	9.2
Private petrol use	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.9	1.1	1.4	1.6
Residential use	2.9	2.9	2.9	3.0	3.0	3.0	3.2	3.3	3.5	3.7	3.9
Net energy exports (Mtoe)											
Total	0.7	0.9	2.8	– 0.3	– 1.1	1.7	3.8	23.2	64.3	87.5	102.1
Oil	3.7	3.5	5.0	1.7	0.9	2.2	3.8	17.0	55.0	79.5	94.1
Gas	– 3.0	– 2.6	– 2.2	– 2.0	– 2.0	– 0.5	0.0	6.2	9.3	8.0	8.0
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	0.72	0.67	0.73	1.01	1.24	1.14	1.02	0.93	0.79	0.80	0.73
Oil prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
Gas prod., transport and refining (toe/toe)	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.26	0.24
Manufacturing industry (toe/US$ thousand)	0.47	0.47	0.50	0.55	0.60	0.60	0.55	0.50	0.46	0.43	0.40
Productive non-industry (toe/US$ thousand)	0.30	0.30	0.32	0.48	0.50	0.45	0.40	0.38	0.36	0.34	0.32
Private petrol use (toe/capita)	0.06	0.06	0.06	0.07	0.08	0.08	0.09	0.11	0.13	0.15	0.17
Residential energy use (toe/capita)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

Table 18 Azerbaijan: economic and energy indicators (low case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	7.2	7.24	7.33	7.4	7.46	7.51	7.9	8.3	8.8	9.2	9.7
GDP (US$ billion)	27.3	27.1	21	16.1	13	11.4	16.0	21.4	27.3	34.9	44.5
Annual GDP growth (%)	– 0.7	– 22.5	– 23.3	– 19.3	– 12.3	7	6	5	5	5	
GDP per capita (US$)	3792	3743	2865	2176	1743	1518	2024	2578	3103	3788	4586
GDP share at current energy prices %											
Net indirect taxes	11.8	6.5	8.9	6.2	2.8	2.9	4.0	5.0	7.0	9.0	10.0
Industry	30.4	29.9	36.7	32.4	34.9	36.0	39.0	39.0	41.0	44.0	44.0
Energy industry	5.1	4.9	5.9	8.0	11.3	14.6	16.2	19.0	22.9	26.7	26.7
Oil prod., transport and refining	2.3	2.2	2.8	3.8	5.9	8.1	10.5	12.9	16.5	20.1	20.2
Gas prod., transport and refining	1.2	1.0	1.2	1.5	2.0	2.8	2.4	2.9	3.1	3.2	3.0
Electricity and heat prod. and distrib.	1.7	1.7	1.9	2.6	3.4	3.7	3.3	3.2	3.3	3.4	3.5
Non-energy industry	25.3	25.0	30.8	24.4	23.6	21.4	22.8	20.0	18.1	17.3	17.3
Non-industry	57.8	63.6	54.4	61.4	62.3	61.1	57.0	56.0	52.0	47.0	46.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	80.0	100.0	120.0	110.0	100.0	100.0	100.0
Gas (US$/toe)	40.0	40.0	40.0	45.0	50.0	60.0	65.0	70.0	70.0	70.0	70.0
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
GDP share at constant energy prices (%)											
Net indirect taxes	11.8	6.5	8.9	6.2	2.8	2.9	4.0	5.0	7.0	9.0	10.0
Industry	30.4	29.9	36.7	32.4	34.9	36.0	37.0	37.0	39.0	41.0	40.0
Energy industry	5.1	4.9	5.9	6.9	8.0	8.9	8.1	9.7	12.2	14.2	14.2
Oil prod., transport and refining	2.3	2.2	2.8	3.2	3.7	4.0	4.4	5.8	8.2	10.0	10.1
Gas prod., transport and refining	1.2	1.0	1.2	1.4	1.6	1.9	1.5	1.7	1.8	1.8	1.7
Electricity and heat prod. and distr.	1.7	1.7	1.9	2.4	2.7	3.0	2.2	2.1	2.2	2.3	2.3
Non-energy industry	25.3	25.0	30.8	25.5	26.9	27.1	28.9	27.3	26.8	26.8	25.8
Non-industry	57.8	63.6	54.4	61.4	62.3	61.1	59.0	58.0	54.0	50.0	50.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50	50	50	50	50	50	50	50	50	50	50
Gas (US$/toe)	40	40	40	40	40	40	40	40	40	40	40
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Table 18 Azerbaijan: economic and energy indicators (low case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	20.4	19.0	18.2	16.0	15.0	14.7	20.1	34.1	57.1	86.1	109.1
Oil	12.3	11.8	11.6	10.3	9.6	9.2	14.0	25.0	45.0	70.0	90.0
Gas	8.0	7.0	6.4	5.5	5.2	5.4	6.0	9.0	12.0	16.0	19.0
Primary electricity	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Electricity production (TWh)											
Total	23.2	23.4	19.7	19.1	17.6	17.0	17.5	22.9	30.2	40.0	52.0
Thermal	22.5	21.6	17.9	16.7	15.8	15.4	16.0	21.4	28.7	38.5	50.5
Domestic primary energy use (Mtoe)											
Total observed	19.7	18.1	15.4	16.3	16.1	13.0					
Total computed	19.2	19.3	16.9	16.5	15.4	14.2	16.3	20.1	23.0	29.6	35.0
Oil prod., transport and refining	0.7	0.7	0.7	0.6	0.6	0.6	0.8	1.3	1.3	3.5	4.5
Gas prod., transport and refining	0.5	0.4	0.5	0.4	0.4	0.4	0.5	0.7	0.6	1.1	1.1
Electricity and heat prod. and distrib.	6.8	6.5	5.4	5.0	4.7	4.6	4.8	6.2	7.7	10.0	12.1
Non-energy industry	3.2	3.2	3.2	2.3	2.1	1.9	2.5	2.9	3.4	4.0	4.6
Productive non-industry	4.7	5.2	3.7	4.7	4.0	3.1	3.8	4.7	5.3	5.9	7.1
Private petrol use	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.9	1.1	1.4	1.6
Residential use	2.9	2.9	2.9	3.0	3.0	3.0	3.2	3.3	3.5	3.7	3.9
Net energy exports (Mtoe)											
Total	0.7	0.9	2.8	-0.3	– 1.1	1.7	3.8	14.1	34.2	56.5	74.1
Oil	3.7	3.5	5.0	1.7	0.9	2.2	3.8	12.1	30.2	51.5	68.1
Gas	– 3.0	– 2.6	– 2.2	– 2.0	– 2.0	– 0.5	0.0	2.0	4.0	5.0	6.0
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	0.72	0.67	0.73	1.01	1.24	1.14	1.02	0.94	0.84	0.85	0.79
Oil prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05
Gas prod., transport and refining (toe/toe)	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.26	0.24
Manufacturing industry (toe/US$ thousand)	0.47	0.47	0.50	0.55	0.60	0.60	0.55	0.50	0.46	0.43	0.40
Productive non-industry (toe/US$ thousand)	0.30	0.30	0.32	0.48	0.50	0.45	0.40	0.38	0.36	0.34	0.32
Private petrol use (toe/capita)	0.06	0.06	0.06	0.07	0.08	0.08	0.09	0.11	0.13	0.15	0.17
Residential energy use (toe/capita)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

Table 19 Kazakstan: summary of high and low scenarios

	1990	1995	2000	2005	2010	2020
Population (million)	16.7	16.6	17.1	17.7	18.5	20.1
GDP (1993 US$ billion)						
high case	74.3	46.6	57.8	73.8	98.7	160.8
low case			55.3	65.7	78.1	113.9
Oil production (Mt)						
high case	25.2	20.5	45.0	70.0	100.0	160.0
low case			40.0	55.0	75.0	130.0
Gas production (Bcm)						
high case	7.0	5.9	9.8	14.7	29.4	34.3
low case			8.0	12.2	14.7	19.6
Coal production (Mt)						
high case	131.4	87.0	72.7	63.6	59.1	52.3
low case			77.3	65.9	63.6	59.1
Oil consumption (Mt)						
high case	27.2	10.4	20.0	33.7	45.5	84.2
low case			15.6	24.4	31.6	51.9
Gas consumption (Bcm)						
high case	14.7	12.5	14.7	18.4	29.4	34.3
low case			12.9	15.9	17.1	19.6
Coal consumption (Mt)						
high case	103.2	75.0	72.7	63.6	59.1	52.3
low case			72.7	61.4	63.6	59.1
Oil exports (Mt)						
high case	– 2.0	10.1	25.0	36.3	54.5	75.8
low case			24.4	30.6	43.4	78.1
Gas exports (Bcm)						
high case	– 7.7	-6.6	– 4.9	– 3.7	0.0	0.0
low case			– 4.9	– 3.7	– 2.4	0.0
Coal exports (Mt)						
high case	28.2	12.0	0.0	0.0	0.0	0.0
low case			4.6	4.6	0.0	0.0

Table 20 Kazakstan: economic and energy indicators (high case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	16.7	16.7	16.9	16.9	16.9	16.6	17.1	17.7	18.5	19.4	20.1
GDP (US$ billion)	74.3	68.2	65.8	59.5	48.7	46.6	57.8	73.8	98.7	126.0	160.8
Annual GDP growth (%)		– 8.2	– 3.5	– 9.6	– 18.2	– 4.3	4.4	5.0	6.0	5.0	5.0
GDP per capita (US$)	4457.1	4078.9	3895.8	3518.6	2886.8	2805.5	3375.9	4162.7	5327.1	6510.7	8007.4
GDP share at current energy prices %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	– 0.3	– 0.7	4.6	5.2	3.2	4.9	5.0	6.0	7.0	8.0	10.0
Industry	33.1	37.0	39.0	38.8	39.5	38.0	40.0	42.0	42.0	42.0	41.0
Energy industry	7.2	7.9	8.2	8.7	10.2	10.1	14.6	17.1	18.4	18.8	17.5
Oil prod., transport and refining	1.7	2.0	2.1	2.3	2.9	3.5	9.3	11.4	12.2	12.9	11.9
Gas prod., transport and refining	0.2	0.3	0.3	0.3	0.3	0.5	1.0	1.3	2.2	2.1	1.7
Coal prod., transport and distrib.	3.1	3.4	3.5	3.4	4.0	2.9	1.4	0.9	0.7	0.5	0.4
Electricity and heat prod. and distrib.	2.1	2.3	2.3	2.6	3.0	3.1	2.9	3.4	3.4	3.4	3.4
Non-energy industry	25.9	29.1	30.8	30.1	29.3	27.9	25.4	24.9	23.6	23.2	23.5
Non-industry	67.2	63.7	56.4	56.0	57.3	57.1	55.0	52.0	51.0	50.0	49.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	70.0	80.0	120.0	120.0	120.0	120.0	120.0
Gas (US$/toe)	30.0	30.0	30.0	35.0	40.0	50.0	70.0	80.0	90.0	100.0	100.0
Coal (US$/toe)	40.0	40.0	40.0	40.0	40.0	35.0	25.0	25.0	25.0	25.0	25.0
Electricity and heat (US$/KWh)	0.018	0.018	0.018	0.02	0.022	0.022	0.025	0.030	0.030	0.030	0.030
GDP share at constant energy prices (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	– 0.3	– 0.7	4.6	5.2	3.2	4.9	5.0	6.0	7.0	8.0	10.0
Industry	33.1	37.0	39.0	38.8	39.5	38.0	39.0	39.0	40.0	40.0	40.0
Energy industry	7.2	7.9	8.2	8.0	8.7	8.4	8.6	8.8	8.9	8.8	8.1
Oil prod., transport and refining	1.7	2.0	2.1	1.9	2.1	2.2	3.9	4.7	5.1	5.4	5.0
Gas prod., transport and refining	0.2	0.3	0.3	0.3	0.2	0.3	0.4	0.5	0.7	0.6	0.5
Coal prod., transport and distrib.	3.1	3.4	3.5	3.4	4.0	3.3	2.2	1.5	1.1	0.8	0.6
Electricity and heat prod. and distrib.	2.1	2.3	2.3	2.3	2.5	2.6	2.1	2.1	2.0	2.0	2.1
Non-energy industry	25.9	29.1	30.8	30.8	30.8	29.6	30.4	30.2	31.1	31.2	31.9
Non-industry	67.2	63.7	56.4	56.0	57.3	57.1	56.0	55.0	53.0	52.0	50.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50	50	50	50	50	50	50	50	50	50	50
Gas (US$/toe)	30	30	30	30	30	30	30	30	30	30	30
Coal (US$/toe)	40	40	40	40	40	40	40	40	40	40	40
Electricity and heat (US$/KWh)	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018

Table 20 Kazakstan: economic and energy indicators (high case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	89.4	91.5	92.7	80.5	72.9	64.4	85.7	110.7	150.7	185.7	211.7
Oil	25.2	26.8	27.9	23.1	20.4	20.5	45.0	70.0	100.0	135.0	160.0
Gas	5.7	6.6	6.5	5.4	3.7	4.8	8.0	12.0	24.0	26.0	28.0
Coal	57.8	57.5	57.7	51.3	48.1	38.3	32.0	28.0	26.0	24.0	23.0
Primary electricity	0.6	0.6	0.6	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7
Electricity production (TWh)											
Total	87.4	86.0	82.7	77.4	66.4	66.7	68.0	84.6	110.5	142.7	183.4
Thermal	80.0	78.8	75.8	69.8	57.2	58.4	60.0	76.6	102.5	134.7	175.4
Domestic primary energy use (Mtoe)											
Total observed	86.8	74.4	81.4	66.7	61.7	54.9					
Total computed	85.4	74.3	75.7	69.5	61.8	57.7	65.2	77.9	96.9	116.4	136.8
Oil prod., transport and refining	1.5	1.6	1.7	1.4	1.2	1.2	2.3	3.5	5.0	6.8	8.0
Gas prod., transport and refining	0.5	0.5	0.5	0.4	0.3	0.4	0.6	1.0	1.7	1.8	1.7
Coal prod., transport and distrib.	3.5	3.5	3.5	3.1	2.9	2.3	1.9	1.7	1.6	1.4	1.4
Electricity and heat prod. and distrib.	24.0	23.6	22.7	20.9	17.2	17.5	18.0	22.2	27.7	35.0	42.1
Non-energy industry	17.0	13.0	15.7	14.4	13.1	10.6	13.2	15.6	20.0	23.6	28.2
Productive non-industry	30.0	23.9	24.1	21.7	19.5	18.1	21.0	25.2	31.4	37.3	44.2
Private petrol use	0.7	0.7	0.8	0.8	0.9	1.0	1.4	1.8	2.2	2.7	3.2
Residential use	8.3	7.5	6.8	6.8	6.7	6.6	6.8	7.1	7.4	7.7	8.0
Net energy exports (Mtoe)											
Total	2.6	17.1	11.3	13.8	11.2	9.5	20.5	32.7	53.8	69.3	74.9
Oil	– 2.0	3.4	3.9	7.1	6.2	10.1	25.0	36.3	54.5	70.1	75.8
Gas	– 6.3	– 3.8	– 8.4	– 6.8	– 5.2	– 5.4	– 4.0	– 3.0	0.0	0.0	0.0
Coal	12.4	18.9	17.0	14.0	10.7	5.3	0.0	0.0	0.0	0.0	0.0
Electricity	– 1.5	– 1.4	– 1.2	– 0.5	– 0.5	– 0.5	– 0.5	– 0.6	– 0.7	– 0.8	– 0.9
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	1.17	1.09	1.24	1.12	1.27	1.18	1.13	1.06	0.98	0.92	0.85
Oil prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05
Gas prod., transport and refining (toe/toe)	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Coal prod., transp. and distrib. (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.26	0.24
Manufacturing industry (toe/US$ thousand)	0.88	0.65	0.80	0.81	0.92	0.81	0.75	0.70	0.65	0.60	0.55
Productive non-industry (toe/US$ thousand)	0.60	0.55	0.65	0.65	0.70	0.68	0.65	0.62	0.60	0.57	0.55
Private petrol use (toe/capita)	0.04	0.04	0.04	0.05	0.05	0.06	0.08	0.10	0.12	0.14	0.16
Residential energy use (toe/capita)	0.50	0.45	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

Table 21 Kazakstan: economic and energy indicators (low case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	16.7	16.7	16.9	16.9	16.9	16.6	17.1	17.7	18.5	19.4	20.1
GDP (US$ billion)	74.3	68.2	65.8	59.5	48.7	46.6	55.3	65.7	78.1	93.6	113.9
Annual GDP growth (%)		– 8.2	– 3.5	– 9.6	– 18.2	– 4.3	3.5	3.5	3.5	3.7	4.0
GDP per capita (US$)	4457.1	4078.9	3895.8	3518.6	2886.8	2805.5	3232.8	3709.6	4213.2	4838.4	5672.7
GDP share at current energy prices %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	– 0.3	– 0.7	4.6	5.2	3.2	4.9	5.0	6.0	7.0	8.0	10.0
Industry	33.1	37.0	39.0	38.8	39.5	38.0	39.0	39.0	40.0	41.0	41.0
Energy industry	7.2	7.9	8.2	8.7	10.2	10.1	14.1	16.0	17.4	18.6	19.3
Oil prod., transport and refining	1.7	2.0	2.1	2.3	2.9	3.5	8.7	10.0	11.5	12.8	13.7
Gas prod., transport and refining	0.2	0.3	0.3	0.3	0.3	0.5	0.8	1.2	1.4	1.5	1.4
Coal prod., transport and distrib.	3.1	3.4	3.5	3.4	4.0	2.9	1.5	1.1	0.9	0.7	0.6
Electricity and heat prod. and distrib.	2.1	2.3	2.3	2.6	3.0	3.1	3.1	3.6	3.6	3.6	3.6
Non-energy industry	25.9	29.1	30.8	30.1	29.3	27.9	24.9	23.0	22.6	22.4	21.7
Non-industry	67.2	63.7	56.4	56.0	57.3	57.1	56.0	55.0	53.0	51.0	49.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	70.0	80.0	120.0	120.0	120.0	120.0	120.0
Gas (US$/toe)	30.0	30.0	30.0	35.0	40.0	50.0	70.0	80.0	90.0	100.0	100.0
Coal (US$/toe)	40.0	40.0	40.0	40.0	40.0	35.0	25.0	25.0	25.0	25.0	25.0
Electricity and heat (US$/KWh)	0.018	0.018	0.018	0.020	0.022	0.022	0.025	0.030	0.030	0.030	0.030
GDP share at constant energy prices (%)											
Net indirect taxes	– 0.3	– 0.7	4.6	5.2	3.2	4.9	5.0	6.0	7.0	8.0	10.0
Industry	33.1	37.0	39.0	38.8	39.5	38.0	39.0	39.0	40.0	40.0	40.0
Energy industry	7.2	7.9	8.2	8.0	8.7	8.4	8.6	8.6	8.8	9.1	9.2
Oil prod., transport and refining	1.7	2.0	2.1	1.9	2.1	2.2	3.6	4.2	4.8	5.3	5.7
Gas prod., transport and refining	0.2	0.3	0.3	0.3	0.2	0.3	0.4	0.5	0.5	0.4	0.4
Coal prod., transport and distrib.	3.1	3.4	3.5	3.4	4.0	3.3	2.5	1.8	1.4	1.2	0.9
Electricity and heat prod. and distr.	2.1	2.3	2.3	2.3	2.5	2.6	2.2	2.2	2.1	2.2	2.2
Non-energy industry	25.9	29.1	30.8	30.8	30.8	29.6	30.4	30.4	31.2	30.9	30.8
Non-industry	67.2	63.7	56.4	56.0	57.3	57.1	56.0	55.0	53.0	52.0	50.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Gas (US$/toe)	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Coal (US$/toe)	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Electricity and heat (US$/KWh)	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018

Table 21 Kazakstan: economic and energy indicators (low case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	89.4	91.5	92.7	80.5	72.9	64.4	81.2	94.8	115.8	141.9	172.9
Oil	25.2	26.8	27.9	23.1	20.4	20.5	40.0	55.0	75.0	100.0	130.0
Gas	5.7	6.6	6.5	5.4	3.7	4.8	6.5	10.0	12.0	14.0	16.0
Coal	57.8	57.5	57.7	51.3	48.1	38.3	34.0	29.0	28.0	27.0	26.0
Primary electricity	0.6	0.6	0.6	0.7	0.8	0.7	0.7	0.8	0.8	0.9	0.9
Electricity production (TWh)											
Total	87.4	86.0	82.7	77.4	66.4	66.7	68.0	79.3	92.6	112.5	137.7
Thermal	80.0	78.8	75.8	69.8	57.2	58.4	60.0	71.3	84.6	104.5	129.7
Domestic primary energy use (Mtoe)											
Total observed	86.8	74.4	81.4	66.7	61.7	54.9					
Total computed	85.4	74.3	75.7	69.5	61.8	57.7	61.3	67.8	75.1	85.0	95.7
Oil prod., transport and refining	1.5	1.6	1.7	1.4	1.2	1.2	2.0	2.8	3.8	5.0	6.5
Gas prod., transport and refining	0.5	0.5	0.5	0.4	0.3	0.4	0.5	0.8	0.8	1.0	1.0
Coal prod., transport and distr.	3.5	3.5	3.5	3.1	2.9	2.3	2.0	1.7	1.7	1.6	1.6
Electricity and heat prod. and distrib.	24.0	23.6	22.7	20.9	17.2	17.5	18.0	20.7	22.9	27.2	31.1
Non-energy industry	17.0	13.0	15.7	14.4	13.1	10.6	10.3	10.6	11.5	12.6	13.6
Productive non-industry	30.0	23.9	24.1	21.7	19.5	18.1	20.1	22.4	24.8	27.2	30.7
Private petrol use	0.7	0.7	0.8	0.8	0.9	1.0	1.4	1.8	2.2	2.7	3.2
Residential use	8.3	7.5	6.8	6.8	6.7	6.6	6.8	7.1	7.4	7.7	8.0
Net energy exports (Mtoe)											
Total	2.6	17.1	11.3	13.8	11.2	9.5	19.9	27.0	40.7	56.9	77.2
Oil	– 2.0	3.4	3.9	7.1	6.2	10.1	24.4	30.6	43.4	57.7	78.1
Gas	– 6.3	– 3.8	– 8.4	– 6.8	– 5.2	– 5.4	– 4.0	– 3.0	– 2.0	0.0	0.0
Coal	12.4	18.9	17.0	14.0	10.7	5.3	0.0	0.0	0.0	0.0	0.0
Electricity	– 1.5	– 1.4	– 1.2	– 0.5	– 0.5	– 0.5	– 0.5	– 0.6	– 0.7	– 0.8	– 0.9
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	1.17	1.09	1.24	1.12	1.27	1.18	1.11	1.03	0.96	0.91	0.84
Oil prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05
Gas prod., transport and refining (toe/toe)	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Coal prod., transp. and distrib. (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.26	0.24
Manufacturing industry (toe/US$ thousand)	0.88	0.65	0.80	0.81	0.92	0.81	0.75	0.70	0.65	0.60	0.55
Productive non-industry (toe/US$ thousand)	0.60	0.55	0.65	0.65	0.70	0.68	0.65	0.62	0.60	0.57	0.55
Private petrol use (toe/capita)	0.04	0.04	0.04	0.05	0.05	0.06	0.08	0.10	0.12	0.14	0.16
Residential energy use (toe/capita)	0.50	0.45	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

Table 22 Turkmenistan: summary of high and low scenarios

	1990	1995	2000	2005	2010	2020
Population (million)	3.6	4.5	5.2	5.9	6.4	7.4
GDP (1993 US$ billion)						
high case	18.7	12.3	12.9	14.6	17.4	25.7
low case			12.3	13.6	15.7	21.2
Oil production (Mt)						
high case	3.4	3.5	10.0	11.0	12.0	14.0
low case			6.0	6.5	7.0	8.0
Gas production (Bcm)						
high case	84.3	35.6	42.9	61.2	85.7	129.8
low case			36.7	49.0	75.9	117.6
Oil consumption (Mt)						
high case	4.8	5.7	7.0	7.0	7.0	8.0
low case			6.0	6.5	7.0	8.0
Gas consumption (Bcm)						
high case	14.5	9.8	9.4	11.3	13.8	18.7
low case			9.6	10.2	12.0	15.4
Oil exports (Mt)						
high case	– 1.4	– 2.2	3.0	4.0	5.0	6.0
low case			0.0	0.0	0.0	0.0
Gas exports (Bcm)						
high case	69.7	25.8	33.5	50.0	71.9	111.1
low case			27.2	38.8	63.9	102.2

Table 23 Turkmenistan: economic and energy indicators (high case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	3.6	3.8	3.8	3.9	4.0	4.5	5.2	5.9	6.4	6.7	7.4
GDP (US$ billion)	18.7	17.4	16.5	18.2	13.0	12.3	12.9	14.6	17.4	21.1	25.7
Annual GDP growth (%)		– 7.0	– 5.2	10.3	– 28.6	– 5.4	1.0	2.5	3.5	4.0	4.0
GDP per capita (US$)	5194.4	4578.9	4342.1	4666.7	3250.0	2733.3	2467.1	2495.9	2710.0	3154.5	3493.7
GDP share at current energy prices %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	6.0	3.0	0.0	2.3	5.8	5.6	6.0	7.0	8.0	9.0	10.0
Industry	30.0	31.0	31.0	31.0	31.8	39.6	43.0	45.0	46.0	47.0	47.0
Energy industry	9.6	10.3	7.7	8.3	8.3	10.2	17.9	22.7	25.8	28.3	29.3
Oil prod., transport and refining	1.5	1.6	1.5	1.7	1.8	2.3	7.7	9.0	8.3	7.4	6.5
Gas prod., transport and refining	7.4	7.8	5.3	5.8	5.6	7.1	9.5	12.6	16.1	19.2	20.6
Electricity and heat prod. and distrib.	0.8	0.9	0.9	0.7	0.8	0.8	0.7	1.0	1.4	1.8	2.2
Non-energy industry	20.4	20.7	23.3	22.7	23.5	29.4	25.1	22.3	20.2	18.7	17.7
Non-industry	64.0	66.0	69.0	66.7	62.4	54.8	51.0	48.0	46.0	44.0	43.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	70.0	80.0	100.0	120.0	120.0	120.0	120.0
Gas (US$/toe)	20.0	20.0	20.0	20.0	25.0	30.0	35.0	37.0	40.0	45.0	50.0
Electricity and heat (US$/KWh)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.015	0.020	0.025	0.030
GDP share at constant energy prices (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	6.0	3.0	0.0	2.3	5.8	5.6	6.0	7.0	8.0	9.0	10.0
Industry	30.0	31.0	31.0	31.0	31.8	39.6	42.0	42.0	43.0	43.0	42.0
Energy industry	9.6	10.3	7.7	8.0	6.6	7.0	10.0	11.3	12.2	12.3	11.7
Oil prod., transport and refining	1.5	1.6	1.5	1.4	1.3	1.4	3.9	3.8	3.5	3.1	2.7
Gas prod., transport and refining	7.4	7.8	5.3	5.8	4.5	4.7	5.4	6.8	8.1	8.5	8.2
Electricity and heat prod. and distr.	0.8	0.9	0.9	0.7	0.8	0.8	0.7	0.7	0.7	0.7	0.7
Non-energy industry	20.4	20.7	23.3	23.0	25.2	32.6	32.0	30.7	30.8	30.7	30.3
Non-industry	64.0	66.0	69.0	66.7	62.4	54.8	52.0	51.0	49.0	48.0	48.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Gas (US$/toe)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Electricity and heat (US$/KWh)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

Table 23 Turkmenistan: economic and energy indicators (high case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	74.4	73.8	48.9	58.4	32.6	32.6	45.0	61.0	82.0	103.0	120.0
Oil	5.6	5.5	5.0	5.2	3.4	3.5	10.0	11.0	12.0	13.0	14.0
Gas	68.8	68.2	43.8	53.2	29.2	29.1	35.0	50.0	70.0	90.0	106.0
Electricity	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity production (TWh)											
Total	14.6	14.9	14.2	12.6	10.5	9.8	9.5	10.2	12.1	15.2	18.9
Thermal	14.1	13.9	13.2	12.6	10.5	9.8	9.5	10.2	12.1	15.2	18.9
Domestic primary energy use (Mtoe)											
Total observed	18.9	14.8	10.5	11.6	13.3	13.7					
Total computed	18.7	16.9	13.3	15.9	13.4	13.8	14.7	16.2	18.3	20.8	23.3
Oil prod., transport and refining	0.3	0.3	0.3	0.3	0.2	0.2	0.6	0.7	0.7	0.8	0.8
Gas prod., transport and refining	5.5	5.5	3.5	4.3	2.3	2.3	2.8	4.0	4.9	6.3	6.4
Electricity and heat prod. and distrib.	4.2	4.2	4.0	3.8	3.2	2.9	2.9	3.0	3.3	4.0	4.5
Non-energy industry	2.3	1.8	1.5	2.1	2.6	3.6	3.3	3.1	3.2	3.2	3.9
Productive non-industry	4.8	3.4	2.3	3.6	3.2	2.7	2.7	2.6	3.0	3.0	3.7
Private petrol use	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.5	0.6	0.8	1.0
Residential use	1.4	1.5	1.5	1.6	1.6	1.8	2.1	2.3	2.6	2.7	2.9
Net energy exports (Mtoe)											
Total	55.5	59.0	38.4	46.8	19.3	18.9	30.3	44.8	63.7	82.2	96.7
Oil	– 1.4	1.7	0.0	1.2	0.5	– 2.2	3.0	4.0	5.0	6.0	6.0
Gas	56.9	57.3	38.4	45.6	18.8	21.1	27.3	40.8	58.7	76.2	90.7
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	1.01	0.85	0.64	0.64	1.02	1.11	1.13	1.11	1.05	0.98	0.91
Oil prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Gas prod., transport and refining (toe/toe)	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.26	0.24
Manufacturing industry (toe/US$ thousand)	0.60	0.50	0.40	0.50	0.80	0.90	0.80	0.70	0.60	0.50	0.50
Productive non-industry (toe/US$ thousand)	0.40	0.30	0.20	0.30	0.40	0.40	0.40	0.35	0.35	0.30	0.30
Private petrol use (toe/capita)	0.04	0.04	0.05	0.05	0.06	0.05	0.06	0.08	0.10	0.12	0.14
Residential energy use (toe/capita)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

Table 24 Turkmenistan: economic and energy indicators (low case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	3.6	3.8	3.8	3.9	4.0	4.5	5.2	5.9	6.4	6.7	7.4
GDP (US$ billion)	18.7	17.4	16.5	18.2	13.0	12.3	12.3	13.6	15.7	18.3	21.2
Annual GDP growth (%)		– 7.0	– 5.2	10.3	– 28.6	– 5.4	0.0	2.0	3.0	3.0	3.0
GDP per capita (US$)	5194.4	4578.9	4342.1	4666.7	3250.0	2733.3	2347.3	2317.4	2456.0	2724.0	2874.7
GDP share at current energy prices %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	6.0	3.0	0.0	2.3	5.8	5.6	6.0	7.0	8.0	9.0	10.0
Industry	30.0	31.0	31.0	31.0	31.8	39.6	40.0	41.0	43.0	46.0	48.0
Energy industry	9.6	10.3	7.7	8.3	8.3	10.2	14.2	17.7	22.6	26.6	29.7
Oil prod., transport and refining	1.5	1.6	1.5	1.7	1.8	2.3	4.9	5.7	5.3	4.9	4.5
Gas prod., transport and refining	7.4	7.8	5.3	5.8	5.6	7.1	8.5	10.9	15.8	19.7	22.7
Electricity and heat prod. and distrib.	0.8	0.9	0.9	0.7	0.8	0.8	0.8	1.1	1.5	1.9	2.4
Non-energy industry	20.4	20.7	23.3	22.7	23.5	29.4	25.8	23.3	20.4	19.4	18.3
Non-industry	64.0	66.0	69.0	66.7	62.4	54.8	54.0	52.0	49.0	45.0	42.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	70.0	80.0	100.0	120.0	120.0	120.0	120.0
Gas (US$/toe)	20.0	20.0	20.0	20.0	25.0	30.0	35.0	37.0	40.0	45.0	50.0
Electricity and heat (US$/KWh)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.015	0.020	0.025	0.030
GDP share at constant energy prices (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	6.0	3.0	0.0	2.3	5.8	5.6	6.0	7.0	8.0	9.0	10.0
Industry	30.0	31.0	31.0	31.0	31.8	39.6	40.0	41.0	42.0	42.0	42.0
Energy industry	9.6	10.3	7.7	8.0	6.6	7.0	8.1	9.0	10.8	11.6	11.8
Oil prod., transport and refining	1.5	1.6	1.5	1.4	1.3	1.4	2.4	2.4	2.2	2.1	1.9
Gas prod., transport and refining	7.4	7.8	5.3	5.8	4.5	4.7	4.9	5.9	7.9	8.8	9.1
Electricity and heat prod. and distr.	0.8	0.9	0.9	0.7	0.8	0.8	0.8	0.7	0.7	0.8	0.8
Non-energy industry	20.4	20.7	23.3	23.0	25.2	32.6	31.9	32.0	31.2	30.4	30.2
Non-industry	64.0	66.0	69.0	66.7	62.4	54.8	54.0	52.0	50.0	49.0	48.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Gas (US$/toe)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Electricity and heat (US$/KWh)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010

Table 24 Turkmenistan: economic and energy indicators (low case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	74.4	73.7	48.8	58.4	32.6	32.6	36.0	46.5	69.0	87.5	104.0
Oil	5.6	5.5	5.0	5.2	3.4	3.5	6.0	6.5	7.0	7.5	8.0
Gas	68.8	68.2	43.8	53.2	29.2	29.1	30.0	40.0	62.0	80.0	96.0
Electricity	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity production (TWh)											
Total	14.6	14.9	14.2	12.6	10.5	9.8	9.5	10.0	11.6	14.1	17.2
Thermal	14.1	13.9	13.2	12.6	10.5	9.8	9.5	10.0	11.6	14.1	17.2
Domestic primary energy use (Mtoe)											
Total observed	18.9	14.8	10.5	11.6	13.3	13.7					
Total computed	18.7	16.9	13.3	15.9	13.4	13.8	13.8	14.8	16.8	18.7	20.6
Oil prod., transport and refining	0.3	0.3	0.3	0.3	0.2	0.2	0.4	0.4	0.4	0.5	0.5
Gas prod., transport and refining	5.5	5.5	3.5	4.3	2.3	2.3	2.4	3.2	4.3	5.6	5.8
Electricity and heat prod. and distrib.	4.2	4.2	4.0	3.8	3.2	2.9	2.9	2.9	3.1	3.7	4.1
Non-energy industry	2.3	1.8	1.5	2.1	2.6	3.6	3.1	3.0	2.9	2.8	3.2
Productive non-industry	4.8	3.4	2.3	3.6	3.2	2.7	2.7	2.5	2.8	2.7	3.0
Private petrol use	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.5	0.6	0.8	1.0
Residential use	1.4	1.5	1.5	1.6	1.6	1.8	2.1	2.3	2.6	2.7	2.9
Net energy exports (Mtoe)											
Total	55.5	58.9	38.3	46.8	19.3	18.9	22.2	31.7	52.2	68.8	83.4
Oil	–1.4	1.7	0.0	1.2	0.5	–2.2	0.0	0.0	0.0	0.0	0.0
Gas	56.9	57.2	38.3	45.6	18.8	21.1	22.2	31.7	52.2	68.8	83.4
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	1.01	0.85	0.64	0.64	1.02	1.11	1.12	1.09	1.07	1.02	0.97
Oil prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Gas prod., transport and refining (toe/toe)	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.26	0.24
Manufacturing industry (toe/US$ thousand)	0.60	0.50	0.40	0.50	0.80	0.90	0.80	0.70	0.60	0.50	0.50
Productive non-industry (toe/US$ thousand)	0.40	0.30	0.20	0.30	0.40	0.40	0.40	0.35	0.35	0.30	0.30
Private petrol use (toe/capita)	0.04	0.04	0.05	0.05	0.06	0.05	0.06	0.08	0.10	0.12	0.14
Residential energy use (toe/capita)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

Table 25 Uzbekistan: summary of high and low scenarios

	1990	1995	2000	2005	2010	2020
Population (million)	20.2	22.5	25.5	28.1	30.8	35.9
GDP (1993 US$ billion)						
high case	62.5	51.1	59.2	72.1	92.0	142.9
low case			56.4	65.4	75.8	101.9
Oil production (Mt)						
high case	2.8	7.6	10.0	11.0	12.0	14.0
low case			9.0	10.0	11.0	13.0
Gas production (Bcm)						
high case	40.4	48.6	51.4	56.3	62.5	73.5
low case			50.2	53.9	58.8	67.4
Coal production (Mt)						
high case	5.0	2.5	2.5	2.5	2.3	2.3
low case			2.5	2.5	2.3	2.3
Oil consumption (Mt)						
high case	10.2	8.6	8.7	9.0	10.0	12.0
low case			8.7	9.0	9.5	11.0
Gas consumption (Bcm)						
high case	37.6	44.2	49.4	55.9	61.6	74.4
low case			46.8	50.9	53.6	61.0
Coal consumption (Mt)						
high case	5.0	2.7	2.5	2.5	2.3	2.3
low case			2.5	2.5	2.3	2.3
Oil exports (Mt)						
high case	– 7.4	– 1.0	1.3	2.0	2.0	2.0
low case			0.3	1.0	1.5	2.0
Gas exports (Bcm)						
high case	2.8	4.4	2.0	0.4	0.8	– 0.9
low case			3.5	3.0	5.1	6.3
Coal exports (Mt)						
high case	0.0	– 0.2	0.0	0.0	0.0	0.0
low case			0.0	0.0	0.0	0.0

Table 26 Uzbekistan: economic and energy indicators (high case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	20.2	20.6	21.1	21.6	22.1	22.5	25.5	28.1	30.8	33.5	35.9
GDP (US$ billion)	62.5	62.2	55.3	54.0	51.8	51.1	59.2	72.1	92.0	114.6	142.9
Annual GDP growth (%)	– 0.5	– 11.1	– 2.4	– 4.1	– 1.4	3.0	4.0	5.0	4.5	4.5	
GDP per capita (US$)	3089.5	3018.0	2619.6	2498.8	2343.9	2274.1	2323.1	2564.0	2985.6	3424.9	3976.9
GDP share at current energy prices %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0		
Net indirect taxes	– 1.1	– 0.3	– 0.9	9.4	8.2	10.0	11.0	11.0	11.0	11.0	11.0
Industry	33.3	36.7	36.1	31.3	30.0	30.0	30.0	30.0	29.0	29.0	29.0
Energy industry	4.1	4.1	4.7	5.7	8.1	11.1	11.7	10.8	9.4	8.3	7.5
Oil prod., transport and refining	0.2	0.2	0.3	0.4	0.8	1.8	2.2	2.1	1.8	1.6	1.4
Gas prod., transport and refining	2.1	2.2	2.5	3.4	5.3	7.0	7.1	6.4	5.5	4.8	4.2
Electricity and heat prod. and distrib.	1.8	1.7	1.8	1.8	2.0	2.3	2.4	2.2	2.0	1.9	1.9
Non-energy industry	29.2	32.6	31.4	25.6	21.9	18.9	18.3	19.2	19.6	20.7	21.5
Non-industry	67.8	63.6	64.8	59.3	61.8	60.0	59.0	59.0	60.0	60.0	60.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	80.0	120.0	130.0	140.0	140.0	140.0	140.0
Gas (US$/toe)	40.0	40.0	40.0	50.0	70.0	90.0	100.0	100.0	100.0	100.0	100.0
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04
GDP share at constant energy prices (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0		
Net indirect taxes	– 1.1	-0.3	-0.9	9.4	8.2	10.0	11.0	11.0	11.0	11.0	11.0
Industry	33.3	36.7	36.1	31.3	30.0	30.0	30.0	30.0	29.0	29.0	29.0
Energy industry	4.1	4.1	4.7	4.9	5.4	5.7	5.3	4.8	4.1	3.6	3.1
Oil prod., transport and refining	0.2	0.2	0.3	0.4	0.5	0.7	0.8	0.8	0.7	0.6	0.5
Gas prod., transport and refining	2.1	2.2	2.5	2.7	3.0	3.1	2.8	2.6	2.2	1.9	1.7
Electricity and heat prod. and distr.	1.8	1.7	1.8	1.8	1.8	1.8	1.6	1.4	1.2	1.1	0.9
Non-energy industry	29.2	32.6	31.4	26.4	24.6	24.3	24.7	25.2	24.9	25.4	25.9
Non-industry	67.8	63.6	64.8	59.3	61.8	60.0	59.0	59.0	60.0	60.0	60.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Gas (US$/toe)	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Table 26 Uzbekistan: economic and energy indicators (high case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	38.57	39.22	40.53	42.74	46.32	49.01	53.70	58.70	64.60	69.60	75.60
Oil	2.81	2.80	3.30	4.00	5.50	7.60	10.00	11.00	12.00	13.00	14.00
Gas	33.00	33.90	35.00	36.80	38.90	39.70	42.00	46.00	51.00	55.00	60.00
Coal	2.20	2.00	1.70	1.30	1.30	1.10	1.10	1.10	1.00	1.00	1.00
Primary electricity	0.56	0.52	0.53	0.64	0.62	0.61	0.60	0.60	0.60	0.60	0.60
Electricity production (TWh)											
Total	56.30	54.20	50.90	49.10	47.80	47.20	48.00	52.20	56.54	62.43	67.68
Thermal	49.80	48.20	44.70	41.70	40.60	40.10	41.00	45.20	49.54	55.43	60.68
Domestic primary energy use (Mtoe)											
Total observed	43.70	46.50	45.20	47.20	45.50	46.50					
Total computed	43.22	45.94	45.44	47.26	47.14	46.69	50.75	56.36	61.92	67.44	74.37
Oil prod., transport and refining	0.17	0.17	0.20	0.24	0.33	0.46	0.60	0.66	0.72	0.78	0.84
Gas prod., transport and refining	2.64	2.71	2.80	2.94	3.11	3.18	3.36	3.68	3.57	3.85	3.60
Electricity and heat prod. and distrib.	14.94	14.46	13.41	12.51	12.18	12.03	12.30	13.56	14.37	14.97	15.17
Non-energy industry	8.20	9.72	9.04	9.26	8.93	8.69	8.78	9.09	9.16	8.74	11.09
Productive non-industry	8.48	9.89	10.75	12.81	12.80	12.26	13.98	16.16	19.32	22.70	25.71
Private petrol use	0.70	0.75	0.80	0.85	0.95	1.08	1.53	1.97	2.46	3.01	3.59
Residential use	8.09	8.24	8.44	8.64	8.84	8.99	10.20	11.24	12.32	13.39	14.37
Net energy exports (Mtoe)											
Total	– 5.13	– 7.28	– 4.67	– 4.46	0.82	2.51	2.95	2.34	2.68	2.17	1.23
Oil	– 7.40	– 8.50	– 5.00	-5.40	– 2.50	– 1.00	1.30	2.00	2.00	2.00	2.00
Gas	2.27	2.32	0.83	1.14	3.62	3.61	1.65	0.34	0.68	0.17	– 0.77
Coal	0.00	– 1.10	– 0.50	– 0.20	– 0.30	– 0.10	0.00	0.00	0.00	0.00	0.00
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	0.70	0.75	0.82	0.87	0.88	0.91	0.86	0.78	0.67	0.59	0.52
Oil prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Gas prod., transport and refining (toe/toe)	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.25
Manufacturing industry (toe/US$ thousand)	0.45	0.48	0.52	0.65	0.70	0.70	0.60	0.50	0.40	0.30	0.30
Productive non-industry (toe/US$ thousand)	0.20	0.25	0.30	0.40	0.40	0.40	0.40	0.38	0.35	0.33	0.30
Private petrol use (toe/capita)	0.03	0.04	0.04	0.04	0.04	0.05	0.06	0.07	0.08	0.09	0.10
Residential energy use (toe/capita)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

Table 27 Uzbekistan: economic and energy indicators (low case)

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Population (million)	20.2	20.6	21.1	21.6	22.1	22.5	25.5	28.1	30.8	33.5	35.9
GDP (US$ billion)	62.5	62.2	55.3	54.0	51.8	51.1	56.4	65.4	75.8	87.9	101.9
Annual GDP growth (%)		– 0.5	– 11.1	– 2.4	– 4.1	– 1.4	2.0	3.0	3.0	3.0	3.0
GDP per capita (US$)	3089.5	3018.0	2619.6	2498.8	2343.9	2274.1	2212.5	2326.7	2460.9	2626.2	2836.8
GDP share at current energy prices %	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	
Net indirect taxes	– 1.1	– 0.3	– 0.9	9.4	8.2	10.0	11.0	11.0	11.0	11.0	11.0
Industry	33.3	36.7	36.1	31.3	30.0	30.0	31.0	32.0	33.0	34.0	34.0
Energy industry	4.1	4.1	4.7	5.7	8.1	11.1	11.9	11.3	10.8	10.3	9.8
Oil prod., transport and refining	0.2	0.2	0.3	0.4	0.8	1.8	2.1	2.1	2.0	1.9	1.8
Gas prod., transport and refining	2.1	2.2	2.5	3.4	5.3	7.0	7.3	6.7	6.3	5.9	5.4
Electricity and heat prod. and distrib.	1.8	1.7	1.8	1.8	2.0	2.3	2.6	2.5	2.5	2.5	2.7
Non-energy industry	29.2	32.6	31.4	25.6	21.9	18.9	19.1	20.7	22.2	23.7	24.2
Non-industry	67.8	63.6	64.8	59.3	61.8	60.0	58.0	57.0	56.0	55.0	55.0
Value added per unit of output at current energy prices											
Oil (US$/toe)	50.0	50.0	50.0	60.0	80.0	120.0	130.0	140.0	140.0	140.0	140.0
Gas (US$/toe)	40.0	40.0	40.0	50.0	70.0	90.0	100.0	100.0	100.0	100.0	100.0
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04
GDP share at constant energy prices (%)		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net indirect taxes	– 1.1	– 0.3	– 0.9	9.4	8.2	10.0	11.0	11.0	11.0	11.0	11.0
Industry	33.3	36.7	36.1	31.3	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Energy industry	2.3	2.4	2.8	3.1	3.5	3.9	3.7	3.5	3.3	3.0	2.8
Oil prod., transport and refining	0.2	0.2	0.3	0.4	0.5	0.7	0.8	0.8	0.7	0.7	0.6
Gas prod., transport and refining	2.1	2.2	2.5	2.7	3.0	3.1	2.9	2.7	2.5	2.4	2.2
Electricity and heat prod. and distr.	1.8	1.7	1.8	1.8	1.8	1.8	1.7	1.6	1.5	1.4	1.3
Non-energy industry	29.2	32.6	31.4	26.4	24.6	24.3	24.6	24.9	25.3	25.5	25.9
Non-industry	67.8	63.6	64.8	59.3	61.8	60.0	59.0	59.0	59.0	59.0	59.0
Value added per unit of output at constant energy prices											
Oil (US$/toe)	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Gas (US$/toe)	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Electricity and heat (US$/KWh)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Table 27 Uzbekistan: economic and energy indicators (low case) – continuation

	1990	1991	1992	1993	1994	1995	2000	2005	2010	2015	2020
Primary energy production (Mtoe)											
Total	38.6	39.2	40.5	42.7	46.3	49.0	51.7	55.7	60.6	65.6	69.6
Oil	2.8	2.8	3.3	4.0	5.5	7.6	9.0	10.0	11.0	12.0	13.0
Gas	33.0	33.9	35.0	36.8	38.9	39.7	41.0	44.0	48.0	52.0	55.0
Coal	2.2	2.0	1.7	1.3	1.3	1.1	1.1	1.1	1.0	1.0	1.0
Primary electricity	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Electricity production (TWh)											
Total	56.3	54.2	50.9	49.1	47.8	47.2	48.0	52.2	56.5	62.4	67.7
Thermal	49.8	48.2	44.7	41.7	40.6	40.1	41.0	45.2	49.5	55.4	60.7
Domestic primary energy use (Mtoe)											
Total observed	43.7	46.5	45.2	47.2	45.5	46.5					
Total computed	42.5	45.2	44.7	46.5	46.3	45.8	48.6	52.3	54.9	58.4	62.4
Oil prod., transport and refining	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.7
Gas prod., transport and refining	2.0	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.9	3.1	3.3
Electricity and heat prod. and distrib.	14.9	14.5	13.4	12.5	12.2	12.0	12.3	13.1	13.4	14.4	14.6
Non-energy industry	8.2	9.7	9.0	9.3	8.9	8.7	8.3	8.2	7.7	6.7	7.9
Productive non-industry	8.5	9.9	10.8	12.8	12.8	12.3	13.3	14.7	15.7	17.1	18.0
Private petrol use	0.7	0.8	0.8	0.9	1.0	1.1	1.5	2.0	2.5	3.0	3.6
Residential use	8.1	8.2	8.4	8.6	8.8	9.0	10.2	11.2	12.3	13.4	14.4
Net energy exports (Mtoe)											
Total	– 5.1	– 7.3	– 4.7	– 4.5	0.8	2.5	3.1	3.4	5.7	7.2	7.2
Oil	– 7.4	– 8.5	– 5.0	– 5.4	– 2.5	– 1.0	0.3	1.0	1.5	2.0	2.0
Gas	2.3	2.3	0.8	1.1	3.6	3.6	2.8	2.4	4.2	5.2	5.2
Coal	0.0	– 1.1	– 0.5	– 0.2	– 0.3	– 0.1	0.0	0.0	0.0	0.0	0.0
Primary energy consumption per unit											
Total energy (toe/US$ thousand)	0.70	0.75	0.82	0.87	0.88	0.91	0.86	0.80	0.72	0.66	0.61
Oil prod., transport and refining (toe/toe)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Gas prod., transport and refining (toe/toe)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Electricity and heat prod. (Mtoe/GWh)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.27	0.26	0.24
Manufacturing industry (toe/US$ thousand)	0.45	0.48	0.52	0.65	0.70	0.70	0.60	0.50	0.40	0.30	0.30
Productive non-industry (toe/US$ thousand)	0.20	0.25	0.30	0.40	0.40	0.40	0.40	0.38	0.35	0.33	0.30
Private petrol use (toe/capita)	0.03	0.04	0.04	0.04	0.04	0.05	0.06	0.07	0.08	0.09	0.10
Residential energy use (toe/capita)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Note: all US$ figures are in 1993 dollars unless otherwise stated.

MARKETS FOR CASPIAN REGION OIL

SUMMARY

By 2010 the combined oil exports of Azerbaijan, Kazakstan, Turkmenistan and Uzbekistan are projected to reach as much as 2.3 million barrels per day (Mb/d). Their future impact on world oil trade is the focus of this chapter.

World oil demand/supply outlook: Global oil demand is projected to increase by around 2.2% annually to reach about 97.1 Mb/d by 2010. Much of the increase in demand is expected to come from Asia. Total non-OPEC production is projected to rise by less than demand, from 40.9 Mb/d in 1995 to 46.6 in 2010. Consequently, the call on OPEC crude is expected to increase to 48.6 Mb/d by 2010.

The onshore and offshore potential of the Central Asian and Transcaucasian region resembles, and could rival, that of the North Sea. However, the resolution of transportation impediments is imperative to unlocking its supplies.

Future world oil trade: An obvious market for Central Asian and Transcaucasian oil is the Mediterranean basin, though an important problem will be how to get the oil there without further burdening the Turkish Straits. Central Europe via the eastern Black Sea states, other FSU countries and ultimately South and East Asia are other possible markets.

As Caspian region projects come on-stream, they are likely to compete directly with western Siberian crude exported from Novorossiysk.

Oil consumption in the Black Sea region is expected to increase by 0.7 Mb/d between 1996 and 2010. Central Asian, Transcaucasian and Russian oil absorbed by this market means less oil that might otherwise pass through the environmentally sensitive Turkish Straits to the Mediterranean and other markets.

Significant inroads into Asia-Pacific markets by Central Asian and Transcaucasian oil producers appear unlikely in the medium term, especially given lack of progress on pipeline projects to the Persian Gulf via Iran and to the South Asian coast via Afghanistan and Pakistan. However, Central Asian and Transcaucasian crude could play an increasing role in China, especially following planned investments by that country in oil production and transportation projects in Kazakstan.

Crude oil quality is an issue, particularly with regard to the mercaptan and sulphur content of fields in the Tengiz area of the northeast Caspian. Otherwise the crudes from Kazakstan and Azerbaijan are generally lighter than most of those from western Siberian that make up the Russian Urals blend.

WORLD OIL MARKET OUTLOOK

Introduction

World oil markets are in a period of change. New technologies are opening up what were previously unexplorable areas, while at the same time geological maturity is bearing down on key producing areas. The political contexts have changed in ways that are allowing private companies to go back into countries that had been shut-off to them. Asian political, economic and energy demand growth has risen to the forefront, and environmental imperatives have taken a prominent place in the global energy economy. Into this mix will enter the oil from new projects in the Central Asian-Transcaucasian region.

By 2010 the combined oil exports of Azerbaijan, Kazakstan, Turkmenistan and Uzbekistan are projected to reach 1.5 - 2.3 million barrels per day (Mb/d). Their future impact on world oil trade is the focus of this chapter.

Key factors that will influence the profile of oil trade competition include an increase in world demand, especially in the Asia-Pacific region – the recent economic crisis notwithstanding – and a growing dependence for supplies on the Persian Gulf.

Growing dependence on Persian Gulf oil

The Gulf OPEC countries hold 65% of the world's proven crude oil reserves and in 1997 accounted for over 40% of its traded oil. Although technology has expanded development horizons and has shortened development times, given projected future world demand and output available from non-OPEC sources, the weight of Gulf OPEC in future world oil trade is expected to increase significantly.

Asia-Pacific demand

The largest per capita increase in oil demand through 2010 is expected to come from the Asia-Pacific region. The impact on oil demand of the region's recent economic crisis, which began in the second half of 1997, will ultimately depend upon the pace of the recovery.[1]

1. Oil demand is particularly prone to currency crises since world oil trade is based in US dollars. The Asian currency depreciation against the dollar could produce a chain reaction that translates into lower purchasing power, income, consumption, investment, and output, and consequently lower increased demand for energy. However, forecasting the impact of the crisis is difficult at this stage, given that spread effects through trade and investment flows are still possible.

East Asia especially is entering the new millennium in a rather precarious position with respect to its growing dependence on energy imports. (Gulf OPEC, Oman and Yemen are currently the dominant oil suppliers to East Asia.)

New alternative suppliers

By 2010 the competition for markets and secure supplies will intensify as new Central Asian and Transcaucasian crudes enter the world market. Such supplies could provide an important counterbalance to dependence on Persian Gulf oil, and make up for possible future declines in the North Sea and elsewhere.

World oil demand

The world economy over the past five years has been characterised by:

- low inflation;
- economic growth patterns in certain OECD and emerging East and South-east Asian countries that exceed their long-term average;
- declining real oil prices, and
- robust oil demand growth, especially outside the FSU.

Supported by accelerating globalisation (i.e., integration and an oil market that is increasingly stimulated by transparency, competition and efficiency), these trends reversed previously held assumptions on the strong correlation between oil demand growth and increasing real oil prices. Current forecasts project burgeoning future demand over the next decade, but in an environment of ample supply and flat real oil prices.

Asian and world energy demand forecasts for the next 2-3 years are strongly affected by the timing and pace of the Asian economic recovery. Nonetheless, in the long run Asia is likely to lead the world in future oil demand growth. This will especially be the case in China and India, where per capita incomes are expected to continue improving, consequently boosting the demand for petroleum products.

Demand outlook

Global oil demand is projected to increase by around 2.2% annually (about 1.7 Mb/d), reaching about 97.1 Mb/d by 2010. Although oil will remain the dominant fuel in the OECD, its share of total consumption will decline for the OECD as a whole from 42% in 1995 to 41% by 2010. This change reflects switching to natural gas and other fuels.

The fastest growth in oil consumption is projected for the developing countries, with Asia and Latin America accounting for a large proportion. This forecast shows a gradual shift in the focus of world energy demand away from the OECD to the developing world. Moreover, 64% of the growth in oil demand is projected to be in the transportation sector.

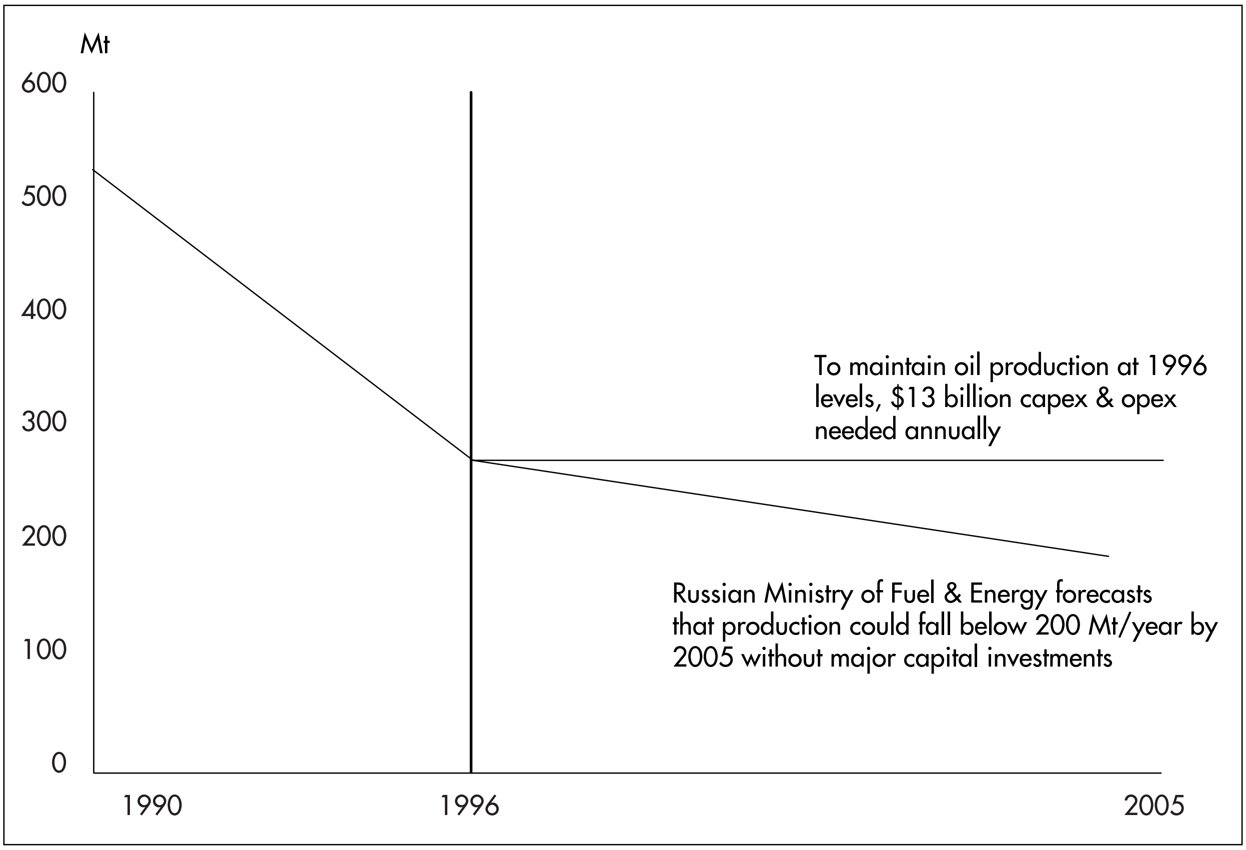
World oil supply

The world supply outlook continues to be stimulated by the liberalisation and integration of the world economy. New acreage is being made available to the world oil industry, which is experiencing the effect of lower E&P costs due to new technology and to significant public policy overhaul in many parts of the world that has substantially lowered barriers to entry of international investment capital. These forces are contributing to rising supplies and consequently to an increase in the number of players that will compete for export markets in the future.

Gulf-OPEC

Although the FSU and Atlantic basin producers will play large roles in meeting long-term future demand, non-OPEC supply growth is expected to slow after 2000. Consequently, Gulf OPEC will again occupy center stage.

Figure 1 Russia: the investment imperative



Sources: Russian Ministry of Fuel and Energy for production forecasts, and World Bank for investment requirements.

Russia

While the decline in Russia's oil production has levelled off, the oil sector remains in need of significant capital injection and changes to its regulatory environment. If these do not occur, the output decline could resume. Investment capital is needed both for maintaining and increasing output from existing fields and for developing new ones.

Atlantic basin

Supply increases from the Atlantic basin can be expected, especially from Venezuela, Brazil, Colombia, Mexico, and Angola.

North Sea output is expected to peak in the first half of the next decade at close to 8.5 Mb/d; about the same time as Caspian oil is expected to begin flowing in significant amounts.

Venezuela's re-opening to foreign participation is one of the most important recent developments in Latin America's energy sector. The country's crude oil output could exceed 5 Mb/d by 2005, implying an additional 4.2 Mb/d to world markets. Additional supplies from Venezuela, Brazil, Colombia and Mexico are projected to add close to 3.5 Mb/d, primarily to the Caribbean market by 2005.

Western Canada is expected to be a future source of new crudes that could exceed 0.7 Mb/d; much of this is expected to be sold in the Midwestern US market. An additional 1 Mb/d should reach world markets from the deep waters of the Gulf of Mexico by 2005.

Supply outlook

Total non-OPEC production is projected to rise by less than demand from 40.9 Mb/d in 1995 to 46.6 in 2010. Since global oil demand is projected to increase by around 2.2% annually on average, to reach about 97.1 Mb/d by 2010, the call on OPEC crude is expected to increase to 48.6 Mb/d by 2010.

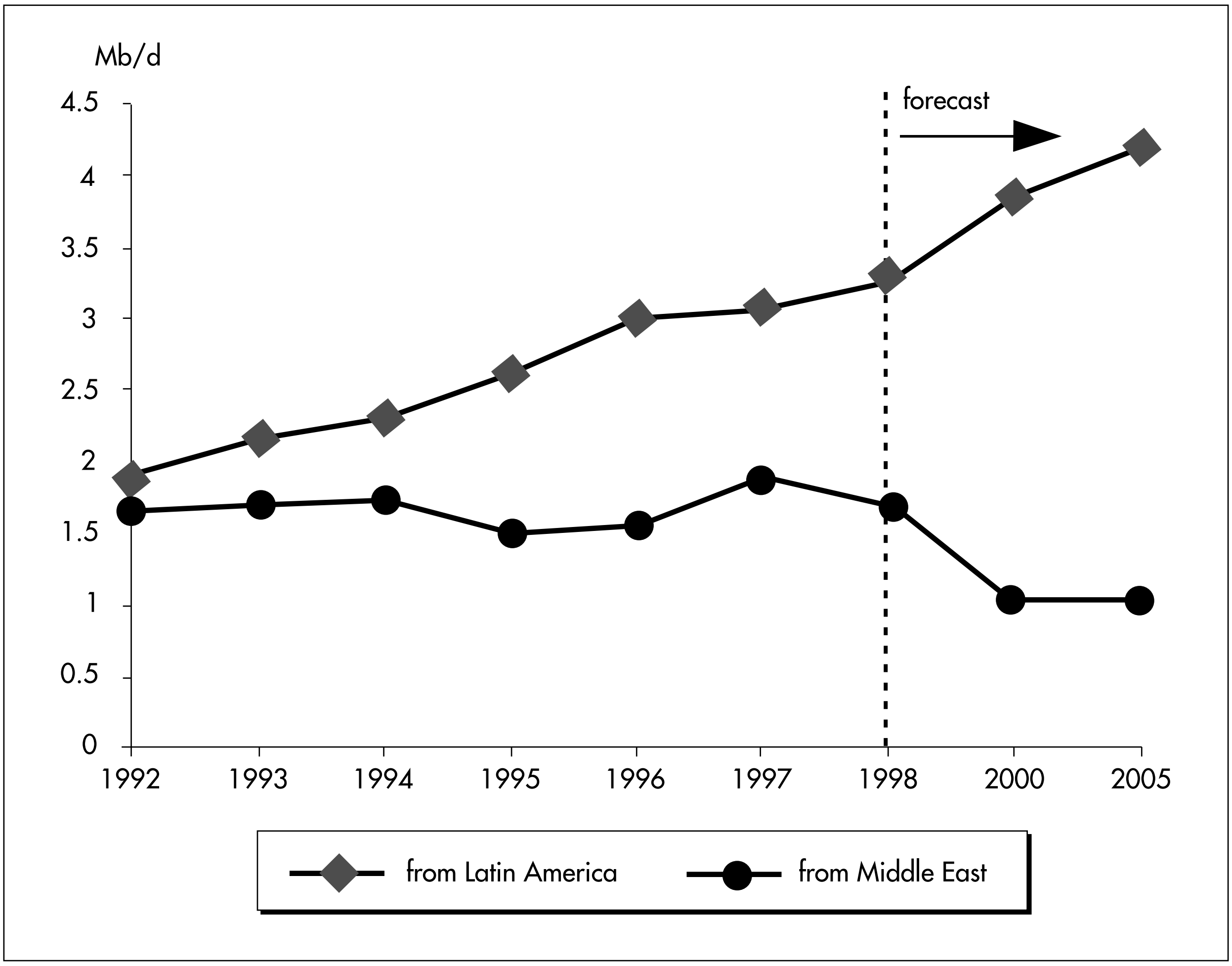
FUTURE WORLD OIL TRADE

Overview

In the Atlantic basin a shift appears to be forming whereby new supplies from Canada, Latin America and Africa are gaining market share at the expense of oil from the Gulf. Middle Eastern crudes have lost market shares in North America, while Latin American crudes are increasingly flowing north.

In European markets, Russian and North Sea supplies compete with Gulf crudes. Much of the Caspian region's oil export capacity will probably be directed westwards, poised to pick-up the slack left by North Sea production declines. Mediterranean markets, in

Figure 2 US crude oil imports from Latin America and the Middle East



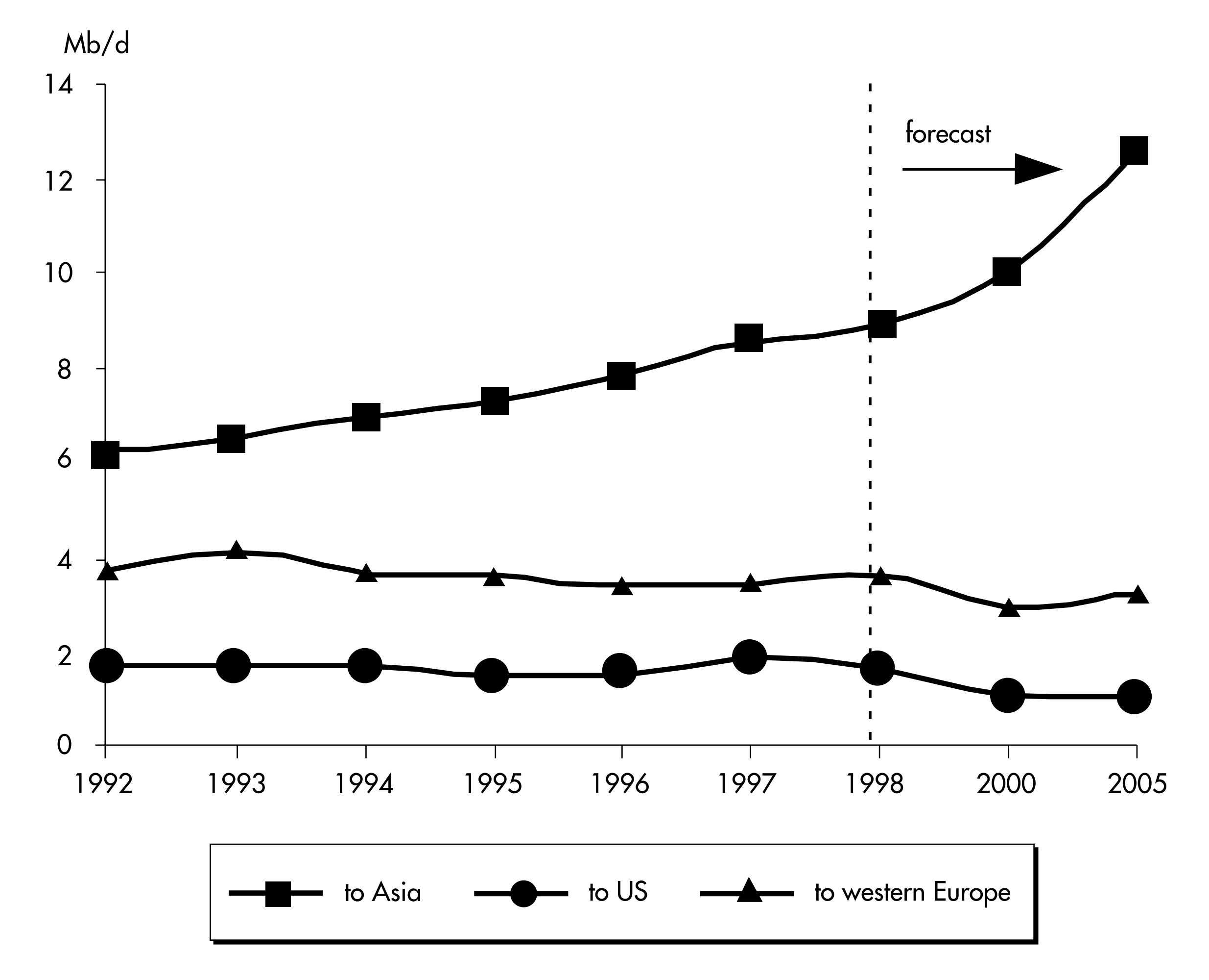
particular, will likely see tough competition between Middle Eastern, Russian and Central Asian/Transcaucasian suppliers.

An uncertainty related to the Asian economic crisis concerns the extent to which a slow-down in energy demand there could re-direct Gulf-OPEC crude to the Atlantic basin. Another key factor could be Iraq, which is seen primarily as a future competitor for other Gulf OPEC. Once the embargo is lifted, Iraq's return to the world market could have a significant impact on both Mediterranean markets (via the existing pipeline through Turkey to Ceyhan) and Asian markets (through the Arabian Gulf).

In the Asia-Pacific market, Gulf OPEC continues to evolve as the dominant supplier. Whether this trend will continue unchallenged depends upon developments in Russia and the Caspian region. Both of these important producing areas aim to supply at least parts of Asia, despite distances and associated high transport costs. While the hurdles facing Russia and the Caspian producers are many, their links with Asia-Pacific are growing, particularly in the case of proposed pipelines from Russia and Kazakstan. Moreover, from Asia's perspective, import diversification with less dependence on Gulf supplies appears to be a desirable objective.

Providing there is an improvement in relations between Iran and key investor countries including the United States, Central Asian and Transcaucasian oil could gain access to Asian markets via the Arabian Gulf. Developing southward capacity for Caspian exports would entail several years of political and construction lead-time, although the seeds of such a scenario may have been planted by the election of a new Iranian president in 1997.

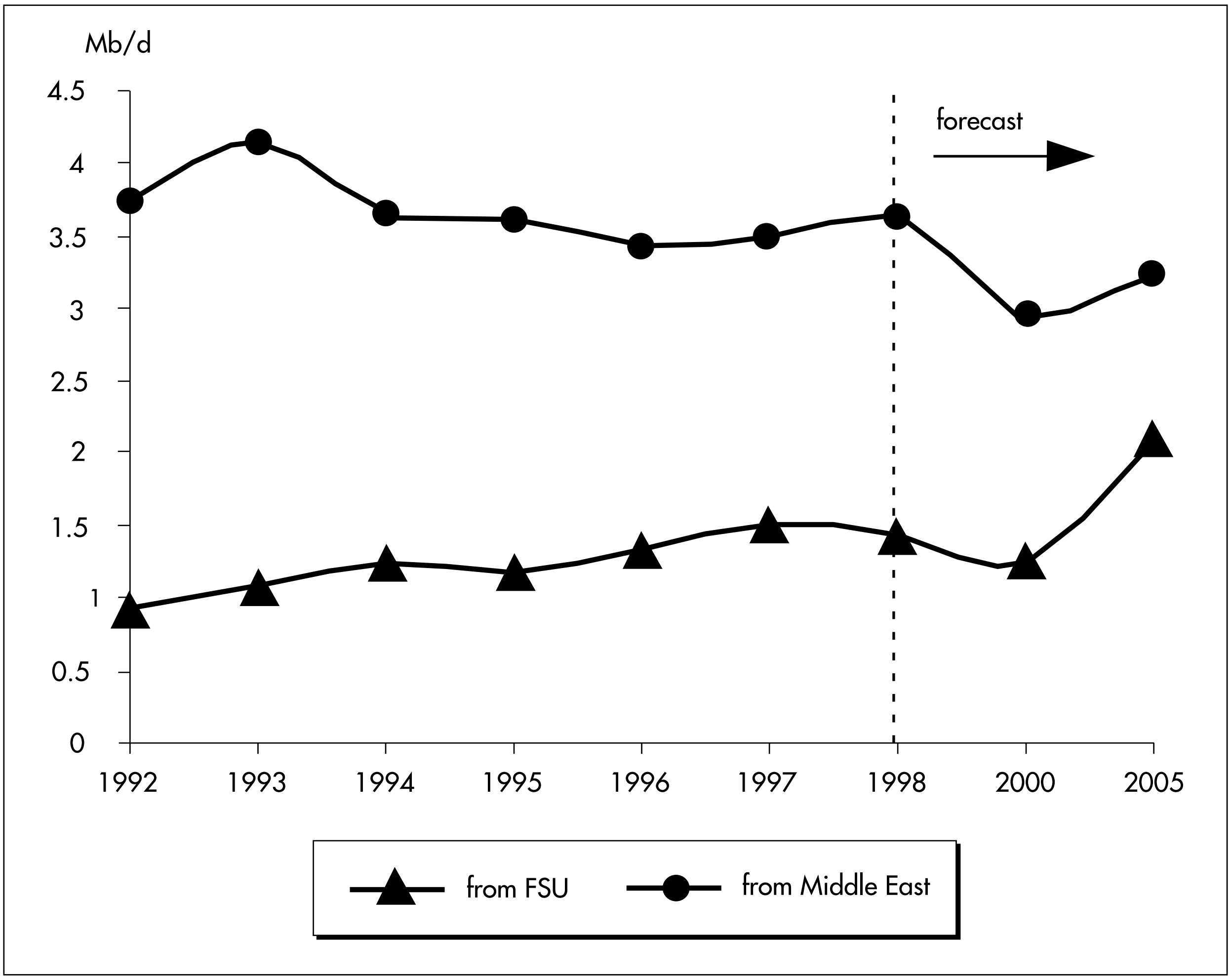
Figure 3 Middle Eastern crude oil exports to Asia, the US and western Europe.



Mediterranean markets

After the turn of the century, Central Asian and Transcaucasian crude is expected to compete strongly with oil from Russia, especifically western Siberian crude exported from Novorossiysk.

Figure 4 Western European imports from the FSU and Middle East



Central Asian and Transcaucasian crudes are of higher quality than Siberian crude and less expensive to produce. Production costs are steadily rising in western Siberia due to a number of factors, including depletion of existing wells, rising water content in the oil, a difficult operating environment and an absence of large new discoveries. Transportation costs are also likely to be more favourable in the case of Central Asian and Transcaucasian oil. The high production and transportation costs of Siberian crude will make it increasingly sensitive to small fluctuations in world oil prices.

The cost of producing one tonne of oil from the Tengiz field in Kazakstan and transporting it to Novorossiysk via the planned CPC route is expected to be US$40/tonne cheaper than producing and transporting the same amount from western Siberia. Moreover, Azeri crude delivered to the Black Sea coast is expected to cost US$50-$55 less per tonne than crude from western Siberia, which costs almost US$85/tonne to produce and transport to Novorossiysk, leaving little room for discounts. Transportation costs alone from western Siberia to Novorossiysk total some US$30/tonne.

Present annual oil supply to the Mediterranean totals 2.9 Mb/d. By 2010, the Caspian region's exports could reach 2.3 Mb/d, much of which would undoubtably end up in the Mediterranean. Moreover, Iraqi production and exports may revive to pre-war levels, causing extreme pressure on prices in the Mediterranean market.

Black Sea markets

Annual oil consumption in the Black Sea region is expected to increase from 1.5 Mb/d in 1996 to 2.2 Mb/d in 2010. Much of the region's 600,000 b/d of refining capacity is not currently utilised. Central Asian, Transcaucasian and Russian oil absorbed by this market will mean less oil that might otherwise pass through the environmentally sensitive Turkish Straits.

Ukraine is building an oil import terminal near Odessa in order to diversify its oil supplies. Initial capacity is to be 12 Mt per year. In addition to purchasing oil for its own use, Ukraine proposes sending oil from this terminal via the Druzhba pipeline to European refineries and/or Baltic ports. However, financing problems have halted construction of the terminal several times.

Effective demand for oil in the former socialist economies bordering the Black Sea is expected to expand in the coming decade, despite macroeconomic adjustment problems some of these countries, notably Romania, are facing.

Romania's domestic economy continues to grow but at a slower pace than its pre-1996 rate, due to serious fiscal deficits fuelled by direct credits and subsidies to its energy intensive industrial and agricultural sectors. Despite relatively healthy oil reserves, Romania is dependent on imports. The government is aiming to negotiate term contracts with Central Asian and Transcaucasian producers to meet the demands of its domestic economy. Additionally, the Romanian government is keen on leasing or selling its spare refining capacity and utilising Romanian pipelines and rivers for west-bound Caspian oil into Europe.

Bulgaria has liberalised prices and continues to introduce policy measures that strengthen that country's structural reform aimed at achieving sustainable future economic growth. The success or failure of adjustment will be a major determinant of the country's future demand for energy.

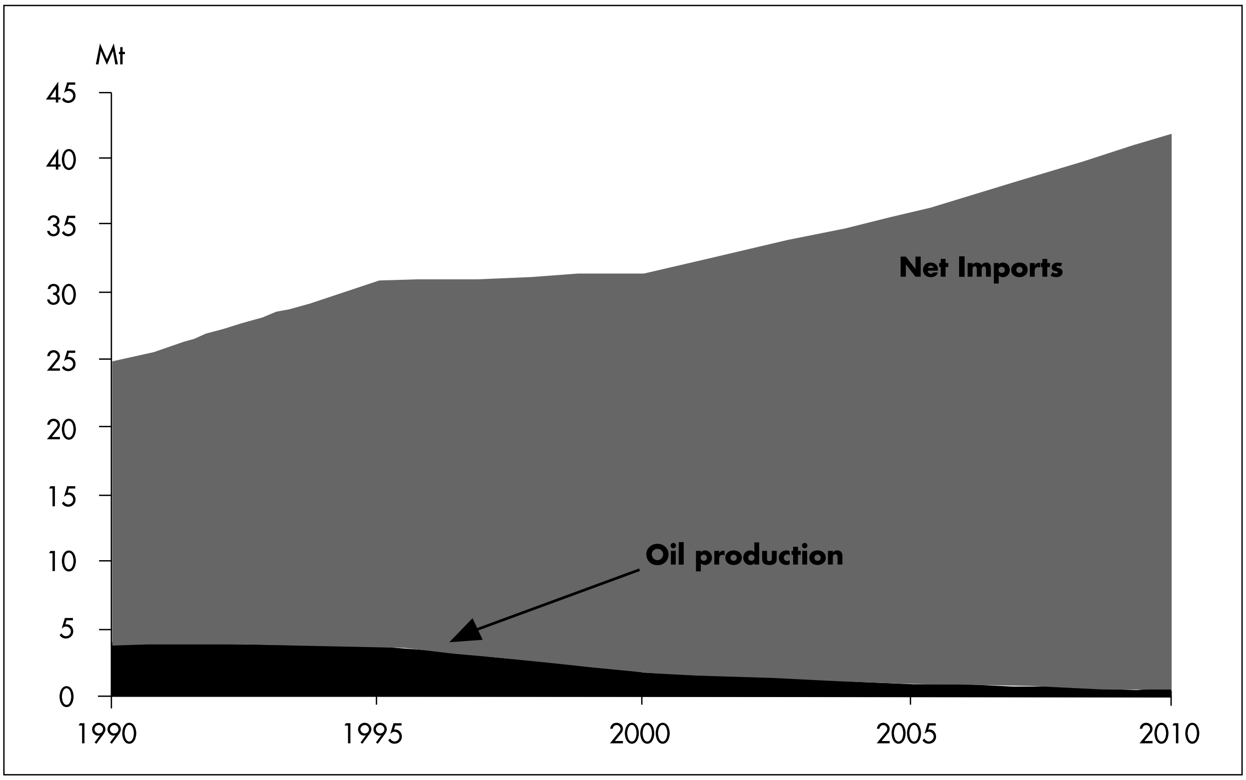
Turkey's economy is experiencing rapid economic growth despite current fiscal and inflationary uncertainties. The country's energy consumption and imports are projected to increase substantially, while domestic oil production is expected to decline.[2]

Turkey's net oil imports rose more than three-fold between 1973 and 1995 and have increased more than 30% since 1990 to reach approximately 545 kb/d in 1995. Before 1990, Iraq was Turkey's largest supplier. After the Gulf war, Turkey increased its crude oil purchases from Saudi Arabia and Iran, from which it received over two-thirds of its total crude oil imports in 1995. Net oil product imports have also increased, with the progressive reduction in refining over-capacity.

2. Oil production has been declining since the early 1990s due to the natural depletion of fields. In 1997 production was about 70 kb/d, which was just 11% of demand.

Given distance and cost considerations, Turkey would appear to be a natural market for future Central Asian and Transcaucasian crude oil exports. Moreover, Turkish companies are actively engaged in crude oil production activities in the Caspian basin, including the AIOC project.

Figure 5 Turkey's dependence on oil imports



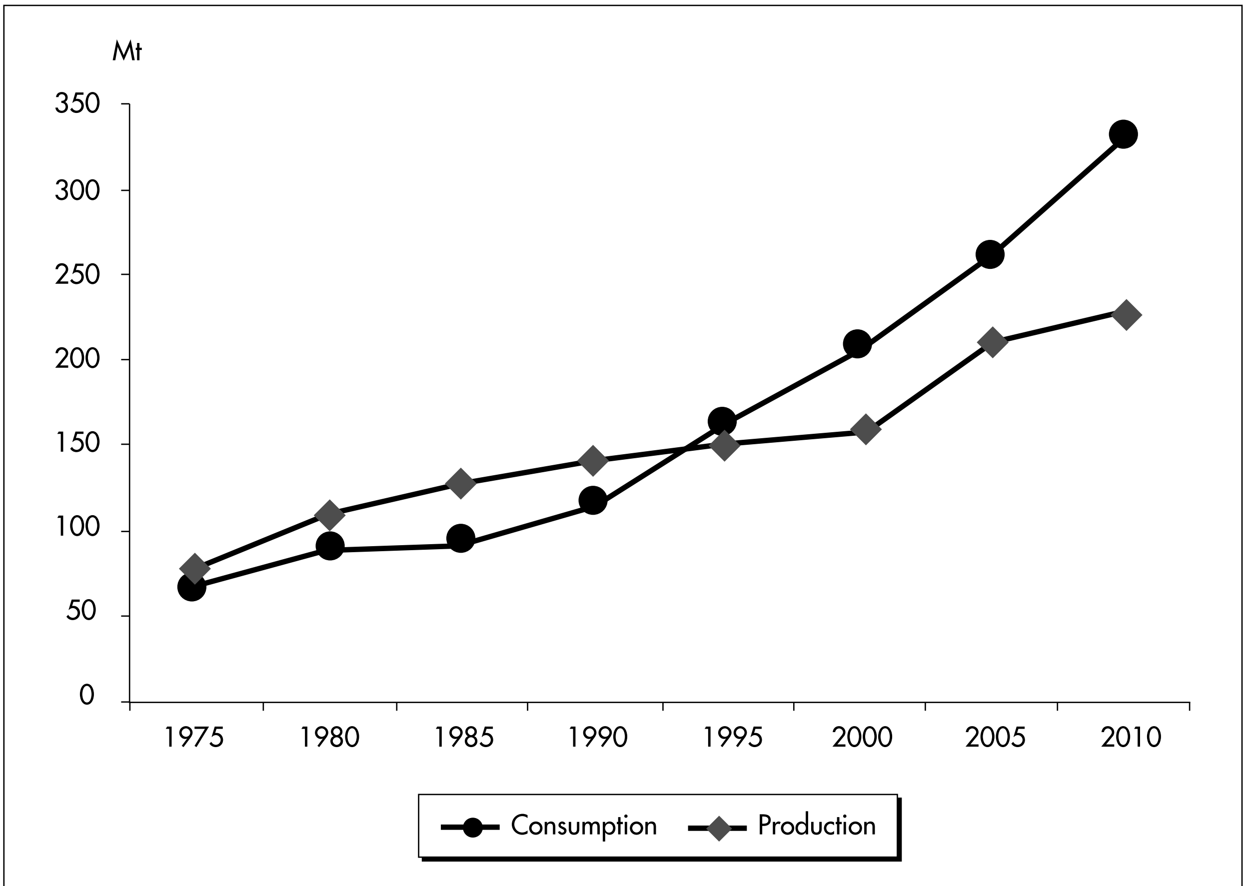
A number of factors could contribute to a decline of Russian exports via the Black Sea. For example, Russian domestic consumption is forecasted to increase; lack of investment may cause overall Russian oil output to fall; port expansions and de-bottlenecking in Northwestern Russia and the Baltics could increase Russian exports via the Druzhba pipeline and the Baltic States' ports, a move which could be accelerated by the arrival of cheaper Central Asian and Transcaucasian crude in Black Sea and Mediterranean markets. Competition from Caspian oil could even hit Russian producers in their own domestic markets, especially in Russia's southern tier where refiners could elect to purchase cheaper crude from Kazakstan and Azerbaijan.

The Chinese market

Significant inroads into Asia-Pacific markets by Central Asian and Transcaucasian oil producers appear unlikely in the medium term, especially given lack of progress on pipeline projects to the Persian Gulf via Iran and to the South Asian coast via Afghanistan and Pakistan. However, Central Asian and Transcaucasian crude could play an increasing role in China, especially following planned investments by that country in oil production and transportation projects in Kazakstan.

China's energy consumption is projected to rise by 4.5% annually over the next 25 years (2% less than its overall GDP growth), though annual oil demand growth is currently much larger at 8%. While coal still dominates China's energy mix, increased urbanisation, use of vehicles, and overall industrialisation has contributed to the country's rising demand for oil and gas. China has been experiencing a serious shortfall in domestic production, and became a net importer at the end of 1993. Although the Tarim basin and the South China Sea are projected to contain large reserves, both will require major development capital outlays and advanced technology.[3] Anticipated net oil import requirements are 0.9-1 Mb/d by 2000 and 2 Mb/d by 2010.

Figure 6 China crude oil production and consumption



While China regards the Middle East as an important supplier of oil, Beijing will probably continue to diversify its energy sources. In doing so it appears to be emphasising supplies over which it has some strategic control. These projects, while outside China, include heavy participation by Chinese companies. For example, CNPC is currently involved in production

3. In the case of the South China Sea, geopolitical issues are at stake as well.

sharing agreements (PSAs) in Canada, Peru, Thailand, Russia, Venezuela, Mongolia, Papua New Guinea, and Sudan, and has signed a US$1.2 billion contact with Iraq to develop that country's Ahdab field. CNPC also has interest in two Kazak oil producers (Aktobemunai and Uzen) and agreed to construct a pipeline from Kazakstan to China's Xinjiang province. Initial capacity of this pipeline is expected to be around 20 Mt per year, rising eventually to 40 Mt per year. A number of observers have expressed doubts about the economic feasibility of the pipeline. In any case, construction could be expected to take six to eight years, making completion of the project some time in 2004 at the earliest.

MARKETS FOR CASPIAN REGION GAS

SUMMARY

Factors affecting production: Central Asian and Transcaucasian gas production will be driven by export market developments, competition in these markets, the outcome of negotiations over access to Gazprom pipelines, the pace of new export pipeline construction, and domestic consumption. The level of reserves is not, and probably will not for a long time become a binding constraint.

Markets: Although South Asia is promising in terms of market dynamics, Afghanistan remains a risky transit country. Turkey may have contracted for more supply than needed, and the eastern, central and western European markets are also well supplied under existing contracts. Ukraine will probably remain a key market as payment problems abate. It may be cheaper for Russia's Gazprom to supply incremental domestic needs with imported gas and incremental exports with gas produced in its own Nadym-Pur-Taz area than to further develop the Yamal peninsula.

Competition from other suppliers: Central Asian and Transcaucasian gas producers face strong competition from established suppliers to Europe and from an array of would-be suppliers to Europe and South Asia, particularly Iran and various Middle Eastern and North African states. The anticipated future level of competition in the European gas market is another reason why Caspian gas producers might be well advised to concentrate their non-FSU efforts on markets in South Asia.

MARKETS FOR CENTRAL ASIAN AND TRANSCAUCASIAN GAS

In principal, there are no limits to where Central Asian and Transcaucasian gas could be marketed. Pipelines already move Siberian gas thousands of kilometres to western Europe. The technical possibility exists to build similar lines to bring Caspian gas to Europe, the Indian subcontinent, China and even East Asia. A line to an LNG terminal on a world ocean could bring other regions within reach. However, there are economic and other constraints on the freedom of Caspian governments and their private partners in choosing an export strategy. For example, many proposed export routes are complicated by transit issues or must traverse politically difficult regions. Some of the area's more ambitious export projects may also require gas prices in excess of current ones to be feasible.

Gas consumption is forecasted to increase faster than other energy consumption in both Europe and Asia for well documented efficiency and environmental reasons. However, price increases are far from certain. In most markets gas prices remain linked to oil prices, and oil companies generally expect little or no increase in real oil prices through 2010. Moreover, potential gas supply in these markets seems to be increasing faster than demand, implying the risks of gas-to-gas competition that could put real gas prices on a declining trend.

This chapter examines the markets that have figured most prominently in discussions of Central Asian and Transcaucasian gas, beginning with those in which the Caspian FSU republics already have positions.

Former Soviet Union

In the 1970s and 1980s Turkmen gas played an important though secondary role in the centrally directed provision of fuel to power plants and other end-users in the Soviet Union. The break-up of the Soviet Union at the end of 1991 did not end this situation, in part because Turkmenistan and other minor FSU gas suppliers remained constrained in their choice of export strategy by existing infrastructure. Until the end of 1997 there were no pipelines that allowed producers in Central Asia and Transcaucasia direct access to markets outside the FSU. All export routes to the so-called "Far Abroad" (markets outside the FSU) went via Russia.[1]

Because inter-republican energy payment problems are severe, FSU countries generally remain markets of last resort to the gas exporters of Central Asia. However, when payment problems are eventually resolved, positions in Ukraine and other FSU gas markets could be valuable assets.

To some extent Turkmen exports to Ukraine have been encouraged by Gazprom, which has wished to reduce its exposure to non-payment problems in the Ukrainian market. Ukraine's virtual monopoly as a transit route for Russian gas deliveries to Europe places it in a strong position vis à vis Gazprom, since Ukraine can compensate for any cuts in supplies by siphoning off deliveries intended for Europe. According to gas expert Jonathan Stern, the implied reward to Turkmenistan for taking over some of Gazprom's non-payment burden in the Ukrainian market is the resumption of profitable Turkmen gas exports to Europe, which were halted by Gazprom in 1994 and had not been resumed as of the beginning of 1998. Turkmenistan has repeatedly confounded any such plans, however, by demanding European level prices for its gas and by refusing to deliver when Ukraine didn't pay.

A December 1997 agreement between Gazprom and Ukraine that lowers the price of gas to Ukraine in exchange for lowering the transit tariff for Russian gas to Europe, may have changed this relationship somewhat, to the detriment of Turkmenistan and other potential Central Asian gas suppliers.[2] The lower price for Russian gas to Ukraine is one with which Central Asian suppliers may not be able to – or at least may not wish to – compete. Moreover, if the new lower price turns out to be one that Ukrainian customers can or will pay, ending years of late or non-payment, Gazprom may have little incentive to further accommodate other suppliers in Ukrainian and other FSU markets, let alone transit arrangements to markets outside the FSU.

1. As of mid-1998 the only exception was a small line from Turkmenistan to northern Iran, opened at the end of 1997 (see Turkmenistan chapter).
2. A price of US$50 per thousand cubic metres to Ukraine in return for a transit tariff for Russian gas to Europe of US$1.01 - 1.09 per thousand cubic metres.

Problems and possibilities in the Russian market are of a different nature. Although Russia is a large gas producer and exporter, Russian gas authorities could decide to import Caspian region gas for cost reasons. Such imports could even free up more Russian gas for export and help Gazprom to avoid developing more costly deposits such as Yamal. However, since Gazprom probably would not be willing to pay European level prices, Russia could be seen by potential suppliers as a market of last resort.

Ukraine

Ukraine received the bulk of Turkmenistan's gas "exports" during Soviet times. It remains Turkmenistan's largest single market, although deliveries were halted in March 1997 over price disagreements and non-payment.

Ukraine is a large, relatively energy inefficient country with a consumption structure reflecting years of systematic substitution away from other fuels to gas. Indigenous gas production covers only one fifth of its needs and, until recently, Ukraine had no alternative to sourcing its imports from Russia and Turkmenistan. In 1990 gas consumption was about 115 Bcm, corresponding to 36 % of total primary energy supply (TPES). By 1995 the consumption of gas had declined to an estimated 73 Bcm, though its share of energy use had increased to 41%. Moreover, gas availability fell as indigenous production dropped and imports were hit by Russia's and Turkmenistan's attempts to increase prices.

The IEA has predicted that under moderately optimistic assumptions on reform policies and economic growth, Ukrainian gas use could recover to about 83 Bcm by 2000 and 110 Bcm by 2010. Ukrainian authorities very optimistically project gas production by 2010 at 35.5 Bcm, while many independent analysts consider that merely stabilising annual output at around 20 Bcm could take a considerable effort. Thus, barring new gas discoveries domestically, Ukraine's import needs could reasonably reach 90 Bcm per year by 2010.

In 1992 both Russia and Turkmenistan attempted to charge "world" prices (typically, European levels of around US$80 per thousand cubic metres) for their gas exports to other FSU republics. In most cases, inability to pay led to mounting debts and cuts in deliveries. Russian-Ukrainian arguments over gas payment terms and arrears on a number of occasions led to drops in pipeline pressure levels at the Ukrainian-Slovak and Ukrainian-Romanian borders. Turkmen-Ukrainian gas pricing and payment clashes usually lasted longer.

By mid-March 1997 Kiev had run up gas debts to Ashgabat of almost US$1.1 billion. Ukraine, whose debts to Russia's Gazprom historically have been even higher than its arrears to Turkmenistan, has been unable to pay for gas supplies in large part because the Ukrainian enterprises involved in gas imports and distribution have similarly been unable to collect payment from their customers.[3]

3. A high share of industrial consumers habitually ignore their gas bills. Among the worst offenders are state enterprises and organisations such as Minenergo (the state holding company for the electricity sector) and the Ministry of Industry. Outside advisors have urged the Ukrainian government to raise prices, improve the metering and billing of gas consumption, and to authorise supply cut-offs in order to force payment by customers that have money but still seem to consider gas as a free good.

Ukrainian authorities have strongly criticised the Russian decision to build a new export pipeline across Belarus and Poland to Germany, arguing that Ukraine stands ready to transit much more Russian gas than it currently does. If Kiev persuades Gazprom to route a high share of incremental gas exports to Europe via Ukraine, and Gazprom convinces Kiev to continue taking payment for transit services in gas rather than cash, Ukraine's incremental gas needs could be covered, more or less, for the foreseeable future by Russia.

The Ukrainian government has nonetheless signalled an interest in diversifying gas imports. In 1997 it began importing 6-10 Bcm per year of Uzbek gas, in part to replace volumes cut by Turkmenistan. Ukrainian leaders have also held exploratory talks with Iran. One plan is to build a pipeline from Iran via Azerbaijan and Russia, while another is to build one or two Ukrainian spurs off of a planned pipeline from Iran to Europe via Turkey. (Such a pipeline could conceivably also carry Central Asian gas.) The first option would have to cross Russian territory, implying Russian participation and possible control, while the second presupposes the existence of a line that remains on the drawing board. Both face financial hurdles related to difficulties in funding projects with Iranian participation. Moreover, neither Iran nor any other new supplier can be expected to extend Ukraine softer terms than those offered by Russia.

Since 1995 the Ukrainian authorities have experimented with gas import liberalisation, though reforms so far have been indecisive and appear driven more by a desire to stave off further cuts in supplies than to put the supply system on sounder financial footing. In the past, Ukrgazprom, a state owned joint stock company, had a monopoly on gas imports and transmission. Currently, half a dozen private or corporatised trading companies handle the bulk of imports from Gazprom, Turkmenistan and Uzbekistan. Turkmen authorities have suggested that if the intermediaries are the problem, gas trade should be re-established on an intergovernmental basis. In March 1997, Ukrainian President Kuchma fired the head of the State Oil and Gas Committee, citing the failure of the new system to stem the accumulation of debts. The responsibility for importing gas is to be given back to Ukrgazprom.

Russia

Russia can influence the Central Asian and Transcaucasian countries' chances of becoming significant gas producers and exporters in a number of ways:

- as an investor or partner in field development and pipeline projects,
- as a transit country for their exports to FSU and other markets,
- as a competitor in most of these markets, and
- as a market in its own right.

The Central Asian republics currently export limited amounts of gas to Russia at prices well below the European levels that the Central Asian countries desire. The future, however, may see an upswing in Russia's needs for Central Asian gas. If the establishment of inter-republican gas trade on commercial terms proceeds apace, Gazprom could theoretically emerge as a customer equally as attractive as European ones.

Such a scenario is rendered plausible by Gazprom's plans to increase its annual exports to Europe from 112.5 Bcm in 1995 to some 200 Bcm by 2010. (Gazprom expects an increase in Europe's gas use from 406 Bcm in 1995 to around 600 Bcm in 2010 and plans to win almost half this incremental market). Gazprom could conceivably import relatively cheap Turkmen and Kazak gas into southern Russia, allowing it to export a higher share of output from producing and new fields in the Nadym-Pur-Taz region in western Siberia. By doing so it could delay potentially expensive new development projects such as fields onshore and offshore the Yamal Peninsula.[4]

Gas industry consultant Jonathan Stern puts Russian imports of Central Asian gas by 2010 at anything between 0 - 60 Bcm. Another expert, Michael Korchemkin, estimates that if Russia decides to increase supply this way, imports from Central Asia by 2010 could amount to around 40 Bcm per year.

Turkey

Turkey plays a key role in Turkmen gas export strategies, and its market is followed closely by other Central Asian gas producers. The potential size of the Turkish gas market makes it a prime target for all producers supplying, or hoping to supply, Europe. Moreover, Turkey provides the only realistic routes for Central Asian and Transcaucasian gas deliveries to Europe that bypass Russia. Many potential Central Asian gas suppliers feel uncomfortable about gas routes via Russia, since that country has little incentive to accommodate competitors in profitable European markets.

Currently, Turkey is a minor gas consumer. In 1995 total gas use amounted to 6.4 Bcm, corresponding to 9.3% of TPES; though only a decade earlier the gas share of TPES was virtually zero. Between 1987 and 1995 consumption increased by an average of 32% per year, and while growth is not forecast to continue at this pace, further significant increases in demand are expected. The Turkish Ministry of Energy and Natural Resources sees total primary energy demand rising by an average of 6.2% per year between 1995 and 2010 (i.e., from 63.1 Mtoe in 1995 to 155.6 Mtoe in 2010) and gas use in particular increasing by an average of 10.5% per year (i.e., to about 31 Bcm, representing 18% of forecasted TPES in 2010). Botas, the national pipeline company, is making arrangements to supply 27 Bcm per year by 2000 and some 60 Bcm per year by 2010 from various sources.

Currently the electricity sector accounts for more than 50% of gas use in Turkey, although gas-based power generation still accounts for only 15% of total generation. Gas consumption by industry and households remains restricted by the current size of the transmission and distribution grids. The one transmission pipeline in operation extends from the Turkish-

4. Yamal offshore fields such as Bovanenko, Kharasavey and Kruzenshtern would be technically challenging, costly, and risky to bring on-stream, since lead times would be so long as to make highly uncertain Gazprom's assumptions on the size of, and the rules of the game and level of competition in, the European gas market by the time production starts.

Bulgarian border via Istanbul, Izmit, Bursa and Eskisehir to Ankara, although spurs are under construction. There are also plans to bring gas to eastern Turkey.

Turkey's own gas production is relatively small. In 1995 the country's seven gas fields yielded a total of 182 million cubic metres. Remaining recoverable reserves are estimated at 8.7 Bcm. TPAO, the national upstream oil and gas company, does not foresee a major increase in production levels. Thus the envisaged massive growth in demand will have to be supplied mostly from imports.

Botas has been negotiating with various sources for further imports to close the envisaged gap between projected demand and contracted supply. As of the beginning of 1998, contracts or memoranda of understanding existed with some 10 different potential suppliers, including Russia and Algeria. In 1994 a liquefied natural gas (LNG) terminal was commissioned at Marmara Ereglisi near Istanbul to accommodate imports of LNG from Algeria.

Turkey began importing gas from Russia in 1987 under a contract that provided for the delivery of 6 Bcm per year for 25 years. The first contract, signed in 1988, stipulates delivery of 2 Bcm per year over a 20-year period. Later contracts provide for total imports of 4 Bcm per year from the late 1990s.

In September 1996 Gazprom and Botas signed a memorandum of understanding to increase deliveries of Russian gas via Bulgaria from 6 to 14 Bcm per year, and to build a pipeline with an annual capacity of 9 Bcm from Russia via Georgia to eastern Turkey. A subsequent memorandum of understanding concerned the construction of a pipeline with an annual capacity of 16 - 18 Bcm from Izobilnoye (location of a compressor station on a pipeline moving Siberian gas to the Northern Caucasus) to Tuapse on the Russian Black Sea coast, with a sub-sea pipeline onward to Samsun or Trabzon on Turkey's northern coast. In December 1997 it was decided to proceed with this project.

In August 1996 Iran signed a major gas export contract with Turkey that provides for deliveries of up to 10 Bcm per year by 2000, continuing through 2020.[5] The estimated value of the project is US$ 23 billion. Construction of a pipeline to move gas into eastern Turkey is reportedly ready to proceed, while Botas has called for bids to build the 300-km segment between the Turkish towns of Dogubeyazit, located close to the Iranian border, and Erzurum, from whence a pipeline could be laid to Ankara. Iran would be responsible for building the 270-km segment from Tabriz to the Turkish border. Turkey has been discouraged from proceeding with this project by the United States, which wishes to isolate Iran economically in order to make it difficult for that country to sponsor terrorism.

Turkish authorities have also turned to Iraq to discuss future gas supply. During 1996 a plan took shape to build a 1,380-km pipeline with a capacity of some 10 Bcm per year from fields in north-eastern Iraq to Anatolia. Turkish authorities reckon that the project would not breach the UN embargo on Iraq, and that by the time such a line could be commissioned, sanctions probably already would be lifted or relaxed. Botas has contracted for delivery of the LNG equivalent of 1.2 Bcm per year from Nigeria. It has signed memoranda of understanding with Egypt for the equivalent of 4 Bcm per year and with Qatar for 1 Bcm per year. It is also negotiating with Abu

5. Deliveries were to start at 3 Bcm in 1997, though as of May 1998 the requisite infrastructure was not in place.

Dhabi, Oman and possibly other LNG suppliers. A US company has carried out a feasibility study on constructing a second LNG import terminal at Iskendrum or Izmir.

In early 1996 the presidents of Turkey and Turkmenistan signed a memorandum of understanding for deliveries of Turkmen gas beginning at 2 Bcm per year in 1998 and increasing to 15 Bcm per year after 2010.

Supplying Central Asian gas to Turkey appears economically feasible. Gas production costs are thought to be around US$18 per thousand cubic metres in Turkmenistan (similar to those in the Middle East and Siberia), and transport costs for moving 7 Bcm per year 2,000 km from Central Asia to Turkey are estimated at around US$60 per thousand cubic metres. Meanwhile, the costs of coal and fuel oil for Turkish power plants (the fuels that Turkmen gas would have to back out) are put at the equivalent of US$127 and US$198 per thousand cubic metres of gas, respectively. If Azerbaijan should find itself with gas available for export, transport costs for moving it to Turkey would be even lower, and Azerbaijan's ability to compete on costs correspondingly better.

There is currently a widespread feeling that Botas' demand forecasts could be over-optimistic and that the company has over-contracted.[6] However, given the difficulties with many of the potential supply sources, not all contracts and memoranda of understanding are expected to lead to actual deliveries.

Iran

Iran has enormous gas reserves, is a major producer and could become an important gas exporter. It could thus become a strong competitor to the gas-producing Central Asian and Transcaucasian republics. However, Iran could also absorb significant amounts of its northern neighbours' output.

Iranian gas consumption is booming. In the mid 1980s the gas share of TPES was about 17%, while today it is estimated at 40%. The Iran-Iraq war led to limits being placed on domestic oil product use. After the war, consumption sky-rocketed, cutting into crude oil exports and threatening to deprive the state of annual revenues approaching US$9-10 billion. The Rafsanjani regime responded by dismantling oil product subsidies and launching a gasification programme. By 1995 about 220 cities and towns with more than three million homes had access to gas. The National Iranian Gas Company (NIGC) reportedly plans to link up another 65 towns, bringing the number of homes with access to gas to 4.7 million by 1999. Total domestic gas use (exclusive of re-injection, flaring and venting) is planned to reach 45 Bcm by 2000.

The Iranian oil industry needs increasing amounts of gas for re-injection into its ageing oil fields (in particular the southern Khuzestan onshore fields and the Kharg island area offshore fields) in order to maintain pressure and output rates. In 1976 plans to boost re-injection to 84 Bcm per year were presented, but the revolution and the war left this target unattained. The Rafsanjani government aims at re-injection of 48 Bcm per year by the turn of the century, but continues to face severe funding problems for such a programme.

6. The World Bank expects Turkish gas demand to increase to 11.5 Bcm in 2010, i.e., to less than 20% of the level forecasted by Botas.

Iran thus currently requires more gas than it can supply internally. Moreover, these needs are expected to increase in the years ahead, if only to substitute for oil in order to allow crude exports to continue at current levels.

Iran's gas pipeline network remains small compared to the size of the country's gas endowments and ambitions. By 1993 around 4,600 km of transmission pipelines carried gas from fields in western and south-western Iran north to Esfahan, Arak, Qom, Tehran, Qazvin, Rasht, Tabriz and Astara. The backbone of the system is Igat-1 and Igat-2, originally built for export, though currently serving mainly domestic customers.[7] The only transmission pipeline apart from these runs from the Sarakhs field near the Iranian-Turkmen border westward to the south-eastern corner of the Caspian Sea.

Building new pipelines from the fields on and off the Iranian Gulf coast to eastern and northern Iran – which do not yet have access to gas – would be very expensive, since distances are considerable and the terrain mountainous. The gas industry will therefore probably give priority to building distribution lines, missing links in the east-west line, and branch lines from the Igat-1 and Igat-2 systems.

In the near future Iran should be able to offer transportation from the Iranian-Turkmen border to its frontier with Turkey. This would allow Iran to could carry Iranian and Turkmen gas to Turkey and to import Turkmen gas into northern Iran. The investment and operating costs of supplying Iranian gas to this part of the country would probably be so high that NIGC could pay relatively high prices for Central Asian gas and still save money. If northern Iranian gas consumption and/or Iranian gas exports to the West grow quickly, deliveries of Turkmen gas could become significant.

Central and eastern Europe

Network-bound energy trade patterns are difficult to break. Nevertheless, a number of countries in central and eastern Europe are scaling down their trade with Russia in the interest of diversifying gas imports. Central Asian and Transcaucasian gas could complement, if not replace, Russian gas in some instances. However, it will probably not be viewed by central and eastern European customers as an alternative unless its supply routes are diversified as well.

If imported via pipelines outside Gazprom's control, Central Asian or Transcaucasian gas could trigger some price competition and provide for added security of supply. As for competitiveness, the Central Asian states might be more willing than other potential suppliers to offer barter arrangements, still an important consideration for some central and eastern European states.

Russia might be more willing to yield shares in its central and eastern European markets than in its western European ones. (Gazprom's offer in late 1996 to reintroduce a Turkmen quota within total FSU gas exports was limited to central and eastern European markets.) However, even here Russia appears reluctant to give up market share, as evidenced by its apparent concessions in

7. Igat stands for "Iran Gas Trunkline".

allowing some re-instatement of barter in contracts with Slovakia and Poland. The central and eastern European states have traditionally imported Russian gas under inter-governmental arrangements linked to their contributions towards the development of Russian gas fields in Orenburg and Yamburg, and not under western style, long-term take-or-pay contracts.

According to Cedigaz, in 1995 Bulgaria, the Czech Republic, Hungary, Poland, Romania and the Slovak Republic consumed a total of 69.7 Bcm of gas, of which they imported 39.3 Bcm, or about 40%. Consumption in these countries could increase to 100 - 110 Bcm per year by 2010, of which import needs are expected to be about 70 - 90 Bcm.

Currently, Central Asian gas can only reach central and eastern Europe through Gazprom's export pipelines running via Ukraine to the Czech and Slovak republics and onward to Germany, or via Ukraine and Moldova to Romania and Bulgaria. These lines have very limited spare capacity and various potential bottlenecks must be removed to allow for envisaged increases in flows.

Only a small share of projected demand in 2010 is already contracted for, meaning that a large portion is still up for grabs. It is attracting strong interest from Russia, which intends to hold onto its old markets, if necessary on updated terms, from other established suppliers to western Europe, and from newcomers. For this reason, the windows of opportunity for Central Asian and Transcaucasian gas in central and eastern European markets may not remain open for very long.

Poland, which could become a transit country for a high share of incremental Russian gas exports, recently signed a long term take-or-pay contract with Gazprom for the delivery of 250 Bcm over a 25-year period. It also signed a letter of intent with Dutch Gasunie on imports of 2 Bcm per year of Russian gas carrying a Gasunie guarantee beginning in 1999 or 2000. Polish gas company POGC is also considering imports of Norwegian gas and the building of an LNG terminal at Gdansk.

In Hungary, Panrusgaz, a JV owned by the Hungarian national oil and gas company MOL and Gazprom, signed a 20-year contract with Gazprom stipulating delivery of a total of 225 Bcm, with the gas set to arrive via Austria as well as Ukraine. Hungary has also contracted with Ruhrgas and Gaz de France for supplies via the new HAG (Hungary-Austria) pipeline.

Serving as transit countries for the bulk of Russia's gas exports to Europe, the Czech and Slovak republics pay less for Russian gas than countries further “downstream”, i.e., below or at the lower end of the range of western European import prices. Transport cost advantages represent a strong argument for continuing to work closely with Gazprom. Nevertheless, for import diversification reasons the Czech Republic has contracted with Norway for the delivery of a total of 53 Bcm over 20 years. Supply diversification has come at a cost, since Norwegian imports are considerably more expensive than the Russian gas they replace. The country also plans to sign a long term contract with Gazprom, and indications are that the Russian company will continue to be the Czech Republic's main supplier.

Slovak authorities so far do not seem interested in even a symbolic diversification of imports. In late April 1997 Slovak and Russian ministers signed a 10-year gas supply contract providing for delivery of as much gas as Slovakia is likely to need during the contract period. Nevertheless, it would appear that Slovakia was able to use the threat of diversification presented by its neighbour's contract with Norway in order to arrange its own deal with Gazprom on largely barter terms.

If any one of the plans to build independent pipelines from Central Asia or Transcaucasia via Turkey to Europe is realised, Bulgaria and Romania would, for location reasons, seem the most likely customers among the central and eastern European states. However, both countries currently import gas exclusively from Russia, and diversification plans are only at an early stage. Neither has hard currency to spare or much room for manoeuvre in reorienting their trade.

Gazprom has had difficulties in Bulgaria recently because of the new government's desire to seem independent of Gazprom. Both Bulgaria and Romania, and especially the former, play extremely important roles as transit corridors in Gazprom's plans to capture a high share of incremental gas demand in the eastern Mediterranean, especially Turkey. Pipelines carrying Russian gas to Bulgaria continue to Turkey, Greece and FYROM (the former Yugoslav Republic of Macedonia). A decision has been made to construct a line from Bulgaria to Serbia, and in the future Russian gas could flow along this southern route all the way to Italy. Thus, old relationships of mutual dependence between Bulgaria and Romania, and of both on Russia, could grow stronger rather than weaker.

There are plans to build an LNG terminal at Constantza, Romania, and intentions to tap into planned pipelines carrying Iranian, Turkmen or Kazak gas via Turkey to Europe as and when any of these pipelines materialise. Projects that are likely to be implemented sooner include one to link into the main system moving Russian gas through Ukraine (so as to achieve at least a diversification of import routes for Russian gas) and another to build a link to the Hungarian network (which would pave the way for access to supplies from the European network).

Western Europe

Western Europe[8] continues to hold a special attraction for potential gas producers in Central Asia and Transcaucasia. It accounts for some 16% of world gas consumption, has shown increasing dynamism in its gas market, is not prohibitively far away, and pays in hard currency.

Western European gas use increased by some 6% (from 330.5 Bcm to 350.4 Bcm) between 1994 and 1995, and a further 10% between 1995 and 1996. In the latter period the United Kingdom saw consumption jump by 16%, while Germany and France posted increases of 12% and 10%, respectively. Even in the Netherlands, where gas already accounted for more than 40% of TPES (indicating that some market segments were close to saturation), consumption rose by 7%. Cold weather played a part, but growth rates also reflected further switching to gas in the power sector and in the residential and commercial sectors. In the United Kingdom, price drops related to increased competition for gas customers gave an extra boost to consumption.

8. Austria, Belgium, Bosnia-Herzegovina, Federal Republic of Yugoslavia, Croatia, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Norway, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

Opinions on how fast the western European gas market will grow in the years ahead form a fairly wide range. The 1996 IEA *World Energy Outlook* forecasts consumption by 2010 at 460 Bcm in its "Capacity Constraints" case, and 340 Bcm in its "Energy Savings" case, i.e., a growth in consumption between 1995 and 2010 of between 8% and 46%. The consultancies DRI/McGraw Hill, Wood Mackenzie and WEFA see demand increasing by 54%, 54% and 50%, respectively, between 1995 and 2010 in their reference scenarios, while Gazprom appears to subscribe to a consumption growth forecast of about 50%. Western companies are generally more conservative in their expectations. For example, Ruhrgas forecasts western European gas use at 380-400 Bcm by 2010.

By mid-1997 western European gas import and transmission companies had already contracted for gas supplies corresponding to forecasted demand through sometime between 2005 and 2008. Some countries are oversupplied now and may remain so under existing contracts through 2010, meaning that they will have to utilise the flexibility in contracts, where available, by nominating minimum volumes. Assuming extensions of most existing contracts and considering that 1) established and new gas suppliers are lining up to fill the remaining gap between supply and forecasted demand (see section on competitors), and that 2) Caspian region gas would not be a particularly cheap alternative, western Europe may not need to tap into Central Asian and Transcaucasian reserves until much later in the new century.

Concerning the competitiveness of Caspian region gas, *L'Observatoire Méditerranéen de l'Energie* in 1995 estimated that the costs of supplying Turkmen gas to western Europe would range from US$127 per thousand cubic metres for deliveries via Iran and Turkey, to US$152 per thousand cubic metres for deliveries via Russia and Ukraine. In comparison, Algerian piped gas would come for US$64 per thousand cubic metres and Russian gas for US$113-131 per thousand cubic metres. Moving out the supply curve for new gas, more than 200 Bcm could be made available to western Europe before it would be necessary to turn to new suppliers in Central Asia and Transcaucasia.

Most forecasters assume explicitly or implicitly that the governing principles of the majority of western European gas markets, including long-term take-or-pay contracts and indexation of gas prices to oil product prices, will remain in place. However, the United States and United Kingdom are providing examples of different ways to organise gas transportation and marketing. Moreover, the European Commission is pushing for a liberalisation of gas markets, as are many large European gas users, including electricity companies, industry and local gas distributors. Meanwhile, the network of transmission pipelines is growing denser, and "hubs" are emerging, making it easier for buyers to shop around. These and other trends could lead to rapid growth in gas spot markets and instances of gas-to-gas competition, pulling prices down and perhaps allowing for even more rapid growth in gas consumption than currently foreseen. Whether supply will grow in step with demand under such circumstances is another question. Some defenders of current arrangements contend that E&P will decline in the face of volume uncertainty in addition to price uncertainty, and that this will gradually affect production, choke off price declines and push consumers back towards long-term contracts.

For some new suppliers, a liberalisation of the European gas market could be good news. LNG shippers and gas suppliers with access to pipelines could conceivably capitalise on opportunities for spot sales. However, increased price and volume uncertainty may make it more difficult to fund new long-distance pipelines. Thus, the Caspian region producers may have little to gain from changes to the "rules of the game" in the western European market.

Pakistan and India

Pakistan

The Turkmen authorities and foreign oil and gas companies operating in Turkmenistan are interested in the Pakistani gas market. (As noted in the Turkmenistan chapter, two groups of companies are planning to build pipelines from fields in southern Turkmenistan via Afghanistan to Pakistan.) This interest is due to the fact that the Pakistani gas market, although not yet very big, is among the world's most dynamic. In 1985 Pakistan consumed 8.1 Bcm of natural gas. By 1995 consumption was up to 18.2 Bcm, representing an average annual growth of 8.4%. Moreover, between 1993 and 1996 Pakistan's gas industry implemented a 30-40% expansion of its transmission and distribution networks, including 700,000 new connections. TPES is forecast to grow rapidly and the gas share of energy use, currently 38%, is expected to increase. Pakistani authorities think consumption could exceed 40 Bcm per year by the turn of the century.

Currently, Pakistan is self sufficient in gas, and indigenous production is forecasted to increase to 28 Bcm in 1998. In the longer term, however, output growth is expected to fall increasingly behind demand. The country's Sui gas field, which was the world's seventh largest when it went on-stream in 1955, and the Mari field, which has been in operation since 1966, are at fairly advanced stages of depletion. The bulk of fields recently put into production, under development or slated for production, are comparatively small.

Most western analysts see Pakistan's gas consumption increasing to about 27 Bcm in 2000, 36 Bcm in 2005 and 48 Bcm in 2010, with annual indigenous production levelling out at 27-29 Bcm. This implies a supply gap opening up only after the turn of the century and increasing to about 20 Bcm by 2010. However, the application of new technology at fields already in production could yield higher than expected recovery rates, and recent and planned improvements in investment conditions for foreign oil and gas companies could lead to new discoveries on an unforeseen scale. Moreover, much of Pakistan remains to be explored. By the early 1990s only 0.42 wells had been drilled per thousand square kilometres of basin.The corresponding figures for India, the OPEC countries and USA were 6, 20 and 301, respectively. On the demand side, if gas price reforms put into effect by the caretaker government that took over in November 1996 are continued, the potential for efficiency improvements in gas consumption could prove to be larger than previously assumed.

These possibilities aside, there is no lack of gas-producing countries in the vicinity that would like to help Pakistan alleviate its looming gas shortage problems. Both Iran and Qatar, in addition to Turkmenistan, are promoting pipeline projects. It is not clear whether Pakistan will be able to support more than one or two such projects, nor whether the Turkmen one is the most likely to be realised in terms of costs, external support and political feasibility.

India

The Indian gas market is the larger prize in producing countries' and companies' race to gain footholds in South Asia. India in 1995 used only marginally more gas than Pakistan, despite its much larger population and economy. But consumption is expected to grow faster here than in Pakistan in the years ahead. Since gas accounts for only 5 - 6% of total primary energy use presently, the potential for substitution from other fuels into gas appears considerable, especially in the electricity sector and certain industries. Most western analysts forecast consumption of up to 38 Bcm per annum by 2000 and 75 Bcm by 2010. Indigenous annual production is forecast to increase to 21 Bcm by 2000 and 38 Bcm by 2010, calling for imports (when compared to western consumption forecasts) of around 16 Bcm in the former year and more than 35 Bcm in the latter.

India is currently looking hard for new supply. Gas could be imported via pipelines from Turkmenistan, Iran, Qatar, Oman or Bangladesh, and/or as LNG from Middle Eastern, Far Eastern and possibly other sources. The pipeline alternatives are fraught with problems, however, since India has strong political and security reservations against receiving supplies via Pakistan. India and Oman have discussed building an offshore pipeline bypassing Pakistan, but the Omanis in 1996 declared this project unfeasible. The Turkmen alternative, besides having to pass through Pakistan, also suffers from instability problems in another transit country, Afghanistan. And the Iranian alternative would have funding problems due to possible sanctions by the United States.

According to the World Bank, exports of Central Asian gas to Pakistan and India are economically feasible. The costs of piping gas approximately 2,500 km from Central Asia to Pakistan are estimated at US$ 60-78 per thousand cubic metres, depending on the level of exports. The costs of sending gas the approximately 3,500 km to India are put at US$81-109 per thousand cubic metres, predicated on the same assumptions with respect to volumes. At the same time the prices of the fuels that would have to be backed out (fuel oil in the case of Pakistan and coal in that of India) are the equivalent of about US$201 and US$120, respectively, per thousand cubic metres.

The competitiveness of Central Asian gas in the Pakistani and Indian markets with that of other potential suppliers is another issue. Supply cost differences lead the World Bank, in a study on gas trade in Asia and the Middle East, to put Middle Eastern producers ahead of Central Asian ones in both markets.

China and Japan

Both Turkmenistan and Kazakstan consider gas exports to China an interesting and feasible long-term alternative. The Chinese gas market is small but growing. In 1995 China's gas consumption amounted to only 16.7 Bcm, corresponding to some 1.8% of TPES. In the IEA's *World Energy Outlook* scenarios, Chinese gas use is expected to increase to 34 - 52 Bcm per year by 2010, though these projections reflect assumptions on high growth in GNP and energy consumption rather than a belief that gas will become a dominant fuel. In both scenarios the gas share of TPES increases, but only to 3.7%. This expectation of only modest switching (from coal) to gas reflects in turn an assumption that supply will become an increasingly tight straitjacket on demand. In other words, if more gas could be produced or imported at competitive costs, the demand would most likely be there. Moreover, pollution problems related to coal burning by power plants, industry and households in urban areas are already extreme and likely to get worse. Chinese leaders would probably implement more vigorous coal-to-gas substitution policies if given opportunities to do so.

Until now China has neither exported not imported gas. Between 1985 and 1995 production increased by an average of 3.9% per year, which is less rapidly than consumption is forecasted to increase. Proven reserves amount to 2,060 Bcm, implying a reserves-to-production ratio of over 120 years. However, a high share of undeveloped reserves are located in inhospitable areas far from consumption centres. Incremental demand may therefore have to be supplied in the medium term from a combination of incremental indigenous production and imports. With respect to local output, in 1994 a US$1 billion rehabilitation and upgrade programme was announced for the Sichuan gas fields, which currently account for about 55% of Chinese output. Chinese leaders also count on an upswing in offshore production.

There are plans to build three LNG terminals with a view to supplying the Pearl River Delta, the Yangtze River Delta and the Fujian area. There are also plans to build pipelines from Yakutsk, Irkutsk and Sakhalin in Russia, and from Turkmenistan and Kazakstan.

Central Asian gas exports to China could be economically feasible, according to the World Bank study referred to earlier. Transport costs for moving 27-28 Bcm per year via a 6,000-km pipeline to consumption centres in east China are put at US$106 per thousand cubic metres, while Chinese power producers pay a price for coal that is equivalent to US$120 per thousand cubic metres of gas. However, margins after adding production and transportation costs would be slim.

The competitiveness of Central Asian gas vis à vis several other possible sources is somewhat doubtful. Although transporting Middle Eastern gas as LNG around India and Malaysia to China could be even more costly than piping Central Asian gas to the same destinations, shipping Indonesian, Malaysian and other Southeast Asian gas as LNG to China would cost about the same. The most competitive option may be to move gas by pipeline from the Irkutsk region of eastern Siberia to eastern China, which, according to preliminary estimates, could be done at a cost of around US$57 per thousand cubic metres.

In 1995 Japan used about 59 Bcm of gas, corresponding to 10-11% of TPES. It imported nearly 100% of this as LNG. Gas consumption increased nine-fold between 1975 and 1995, but is forecast to grow by only 2 - 3.7% per year between now and 2010. Japan buys gas from the United States and Abu Dhabi in addition to all the major Asian exporters. Its needs are covered by contracts extending until well into the next century, though a number of projects have been identified with a view to extending this period of balance between contracted supply and forecasted demand. Japan is aiming for further import diversification, and Qatar and other Middle Eastern countries, which have launched themselves as LNG exporters, have obtained contracts with Japanese utilities. Japan's interest in stretching the proposed Turkmenistan-China pipeline to Japan (see Turkmenistan chapter) is probably more an expression of long-term thinking about security of supply rather than a declaration of intent to support such a project in the near future. Importing Russian gas via pipeline (e.g., from Irkutsk) is probably a more economic long-term option.

Summary

Adding up forecasted demand in all markets that could, in principle, import gas from the Caspian region yields an impressive figure. Western, central and eastern Europe might consume over 600 Bcm per year by 2010, compared to 420 Bcm in 1995. Projections of Turkey's gas needs by 2010 range, as noted, from 12 to 60 Bcm per year, with the Turkish Ministry of Energy and Natural Resources' expectation of around 30 Bcm per year representing the middle ground. Pakistani and Indian consumption could increase from 37 to 120 Bcm per year, Chinese consumption from 17 to 80 Bcm per year, and Japanese consumption from about 60 to 80-100 Bcm per year between 1995 and 2010. Finally, Ukrainian gas demand is projected to grow by 50% to some 110 Bcm. Taken together, these markets are seen as expanding their annual demand from about 615 Bcm to more than one trillion cubic metres. This does not even include Russia and Iran, which may wish to import gas for economic optimisation purposes.

From projected needs, however, must be deducted contracted volumes. As noted, western European needs appear fully covered until sometime between 2005 and 2008. The central and eastern European countries are only now beginning to import gas under regular long-term contracts, but agreements and ongoing negotiations with Gazprom indicate that Russia will remain their key foreign supplier. Turkey appears to have signed enough memoranda of understanding with exporters other than Central Asian ones to be fully supplied for decades ahead. The other non-FSU markets are covered by contracts and agreements to a lesser extent, but are also more difficult to access for distance and geopolitical reasons.

One should also adjust for the high probability of contract extensions, while keeping in mind that an established supplier to a particular market generally has an easier job than a new supplier in landing contracts; the exception may be cases where buyers aim specifically to diversify imports. Moreover, an established exporter with a good track record may be preferred to a new, untried exporter by an importing countries, even in the absence of previous contracts. Finally, the chances of Caspian gas producers getting to fill remaining supply-demand gaps would depend on the level of competition in individual markets.

The following section takes a closer look at the competitors to the Central Asian and Transcaucasian states, including their reserves, current positions, ambitions and strategies.

COMPETITORS

Established competitors in western Europe

Norway, Netherlands and United Kingdom

Norway, the Netherlands and the United Kingdom together hold 86% of western Europe's proven gas reserves and in 1995 accounted for 76% of its production. The three countries are at different stages of maturity as gas producers. Norway's reserves of 3,000 Bcm and 1995 output of 32 Bcm yield a reserves-to-production (r/p) ratio of almost 95 years. The Netherlands' reserves of 1,815 Bcm and 1995 production of 78.4 Bcm implies an r/p of 23 years, and the UK's 700 Bcm and 1995 production of 76 Bcm an r/p of 9 years.

Norway counts on extensions of current contracts with Germany, France, the Netherlands, Belgium, Austria, Spain, Italy and (since March 1997) the Czech Republic. It ponders whether and how sales could be increased without triggering gas-to-gas competition and provoking calls for price discounts. It would also like to resume exports to the United Kingdom, further strengthen its position in southern Europe and gain shares of the central and east European markets. Norway could face future competition with Central Asian and Transcaucasian suppliers in the latter markets especially.

Dutch gas production is kept in line with domestic demand and exports, while the Netherlands' own gas market is close to saturation. At the same time, Gasunie, the company in charge of imports, exports and transmission, is restricted in its pursuit of export contracts. These factors have together caused output to fluctuate for a number of years around a flat trend. Recently the huge Groningen field, the backbone of the Dutch gas industry, has shown signs of depletion. This could make Gasunie's position as western Europe's swing producer difficult to sustain. Dutch authorities have responded by lifting restrictions on exploration and development in some environmentally sensitive areas and by improving licensing terms. Moreover, in a recent White Paper on energy policy, they proposed giving Gasunie more freedom to position itself as a gas trader. The company has already moved toward a more aggressive export strategy. In 1996 it formed a strategic alliance with Gazprom aimed at central and eastern European countries striving for a diversification of imports. Gazprom will deliver the gas physically, but the Dutch company will guarantee deliveries using supplies from Groningen as a back-up. Although Dutch hopes of landing a firm contract along these lines with the Czech Republic have been frustrated, other buyers could find the offer of relatively cheap Russian gas coming with a Dutch guarantee attractive.

British gas production increased by more than 50% between 1990 and 1995. (The level of activity on the UK continental shelf illustrates how misleading r/p ratios can be as a production forecasting tool.) The United Kingdom, which until now has only produced gas for domestic consumption, may in the near future join the ranks of Europe's gas exporters. The Interconnector pipeline between Bacton and Zeebrugge is slated for completion in 1998 and will be able to move 20 Bcm per year from the UK to continental Europe, and 9 Bcm per year in the opposite direction.

Russia

Russia possesses more than one-third of the world's proven gas reserves and in 1995 accounted for over a quarter of its production and almost half of its exports.[9] Russia's Gazprom has considerable market power in the FSU and central and eastern European gas markets, making entry conditions for other producers and exporters potentially very difficult, although the diversification of supplies could be important to a number of governments. Gazprom is also a strong player in western Europe and could become one in key Asian markets.

9. Including Russian exports to the other FSU republics.

Gazprom's finances do not mirror the company's strong position in terms of gas reserves, output and exports. By April 1997 Gazprom was owed a total of 69.5 trillion roubles by Russian gas consumers, and in turn owed some 20 trillion roubles to the federal budget. Moreover, payment problems are reportedly escalating rather than coming under control. Under such conditions Gazprom will probably want to further strengthen its position in more solvent markets.

Gazprom intends to boost annual deliveries to Europe by 50 Bcm (to an annual total of some 170 Bcm) over the next few years. Such a growth in exports would require additional pipeline capacity, and Gazprom is implementing several major transportation projects. It is building the so-called Yamal pipeline, which will initially run from the Nadym-Pur-Taz region via Belarus and Poland to western Europe. It is also building new pipelines via Moldova, Romania and Bulgaria to south-eastern Europe; these lines could strengthen Gazprom's hold on markets of prime interest to Transcaucasian and Central Asian gas producers. The Russian company is also planning to build a sub-sea pipeline across the Black Sea to Turkey, though water depths of up to 2,000 metres spell major engineering challenges and high costs.

Positioning itself to capture a high share of incremental demand, Gazprom has set up a string of trading houses in European countries to buy Russian gas. Recently some of these have tried to take over import contracts and explore possibilities for engaging in direct sales to industry and power plants, as well as spot sales. None of the Caspian area gas producers currently have the resources to prepare for future market share battles in this way.

Gazprom's goals in Asia are perhaps less precise. In 1996 Gazprom joined the Unocal-led consortium which hopes to construct a pipeline from Turkmenistan via Afghanistan to Pakistan, although later pulled out. Gazprom also sees China as a possible market for eastern Siberian gas. Since 1994 Russian and Chinese experts have been working on a scheme to build one or more large gas pipelines from fields north-west of Lake Baikal (near Irkutsk) across Russia and China to the Yellow Sea. In 1996 President Boris Yeltsin and his Chinese counterpart, Jiang Zemin, signed an agreement providing for the completion of feasibility studies within two years, and an intergovernmental agreement on building a gas pipeline with an annual capacity of at least 20 Bcm via Mongolia to China. Although this project could be seen as a competitor to the Turkmenistan-China-Japan project, the Chinese market is potentially large enough to handle both. Nevertheless, the eastern Siberian project would appear to be more economic and to have a more obvious market.

There is some speculation that Gazprom could be split into several companies, of which one would provide transportation services on a commercial basis to foreign as well as Russian gas producers, though such a restructuring, if it happens at all, is probably many years away. The Russian Government is also under strong pressure from the IMF and other IFIs to reign in the monopolies supplying network-bound energy (United Energy Systems and Gazprom), and First Deputy Prime Minister Boris Nemtsov has tried to reassert the government's role in running Gazprom. Other reforms put on the agenda have been the introduction of a single transport tariff for all gas producers, and competition for rights to exploit new reserves. However, in the face of protests from industrial lobbies and the State Duma, such plans appear to have been shelved for the time being.

Algeria

Algeria is the largest gas producer among the Mediterranean littoral states, as well as in OPEC, although several members have larger reserves. Proven reserves are estimated at about 3,700 Bcm. Gross production in 1995 was 136.1 Bcm, but almost half of this was re-injected and close to 10% flared, vented or lost, leaving marketed output at 58.1 Bcm. Algeria's r/p ratio in 1995 was about 53 years. Some 37.5 Bcm (65% of marketed output) was exported, primarily to Italy, France, Spain and Belgium.

Social, religious and political unrest hangs over petroleum activities in Algeria. The authorities have so far managed to protect the oil and gas fields, which lie in the south of the country, as well as the pipelines, which run northward to the coast, north-westward to Tunisia and north-eastward to Morocco. The Islamic opposition is thought to have neither the resources nor the organisation to mount massive attacks on these installations. Nevertheless, the southern European countries receiving Algerian gas via the Transmed and Maghreb-Europe pipelines, or as LNG, have taken care to diversify their imports.

In 1996 Sonatrach, the Algerian state oil and gas company, entered into a combined E&P and marketing deal with BP. The UK company is to develop known fields and look for new ones in an area southwest of the key Hassi R'Mel field, with a view to exporting the output to southern Europe. The deal has been hailed as an important testimony to both foreign willingness to invest in Algeria and Algeria's increasing pragmatism in its dealings with foreign companies. It could help Algeria avoid falling behind in the struggle for positions in the European market.

Sonatrach is optimistic about the future. It expects to increase annual gas exports to around 60 Bcm in the medium term, and possibly to 100 Bcm in the long term. Exports are to be roughly evenly divided between piped gas and LNG. The annual capacity of the Transmed line to Italy could be raised from 24 to 30 Bcm by the addition of two compressor stations. The annual capacity of the Maghreb-Europe line to Spain could similarly be increased from 8.5 to 18.5 Bcm.

Barring a serious turn for the worse in its domestic political situation, Algeria looks set to remain a strong player, especially in southern European gas markets. Transportation distances are short and Sonatrach has gained a reputation for efficiency and aggressiveness. Central Asia is already facing Algerian competition in the Turkish market, and could do so in other European countries in the future.

New competitors in Europe and elsewhere

Iran

As noted earlier, northern Iran could become a market for Turkmen gas. Iran also looks set to become a partner in Turkmenistan's plans to sell gas to Turkey and other European countries. However, the dominant feature of Iran's long-term relationship to Central Asian gas producers and exporters could be that of a strong competitor in both European and South Asian markets.

Iran's 21,000 Bcm of proven gas reserves are truly gigantic, making North America's 6,500 Bcm and western Europe's 6,400 Bcm pale in comparison. Only Russia can boast larger reserves.

In 1978 Iran's gross gas production was about 55 Bcm. The Iranian revolution, followed by the war between Iran and Iraq, caused Iranian gas production to plummet to a low of 16 Bcm in 1981. However, the later war years saw a gradual recovery which strengthened in the post-war period. In 1995 gross output was 75.5 Bcm, and by 1997 it was estimated to have reached 80 Bcm. Despite such growth and an r/p ratio of about 260 years, Iran remains a gas producer on the same fairly modest scale as the Netherlands and the United Kingdom.Although r/p ratios can be incomplete guides to what output could and should be, Iran's gas resources clearly remain underutilised.

In 1992 the Iranian government announced a 20-year gas development programme, which aims to take annual production to 310 Bcm. Under this programme, annual exports were to grow to about 50 Bcm, primarily on the basis of a project to sell gas to Turkey and other European countries (via a proposed pipeline to eastern Turkey) and another to sell gas to Asia (via a proposed pipeline along the continental shelf of Iran and Pakistan, or overland via Pakistan to India). Recent speeches by Iranian leaders indicate that they continue to adhere to this vision. In 1997 the Iranian government forecasted exports to be in the range of 40 - 45 Bcm per year by 2005.

Iran's only export contract signed to date is the one with Turkey. The planning and financing of a 270-km pipeline from Tabriz to the Iranian-Turkish border is reportedly proceeding and in early 1997 the Turkish authorities tendered bids for the construction of a 300-km section from the border to Turkey's Erzurum region. The Iran-Pakistan-India project remains blocked by Pakistani-Indian relations, since India wants neither to be at the end of a pipeline controlled by Pakistan, nor to contribute to the Pakistani economy through transit tariff payments.

Because of sanctions, Iranian authorities have a difficult time funding E&P and pipeline projects. It may therefor take Iran longer to establish itself as a significant gas exporter than its authorities profess to believe. However, as and when conditions for Iranian gas exports improve, other Caspian gas producers could be edged out of key markets by their southern neighbour. The current spirit of co-operation between Iran and Turkmenistan could easily come unstuck, since the two are the region's largest gas producers and eye the same export markets.

Middle Eastern and African competitors

Qatar's gas reserves are estimated at 7,100 Bcm, with the bulk located in the offshore North field, the largest non-associated gas field outside Russia.[10] The North field is being developed in stages by various consortia. Qatargas, which includes Total, Mobil, Mitsui, Marubeni and the Qatari Government, is to produce LNG for exports to Japan. Rasgas, a JV between Mobil and the government, plans to supply LNG to South Korea, Thailand, Taiwan, China, India and Turkey. A third LNG project, driven by Enron and directed at the Israeli, Jordanian, Italian and Indian

10. Russia's Urengoy, Yamburg and possibly Boranenko are larger.

markets, has been delayed. If the Qatargas and Rasgas projects are implemented on schedule, Qatar could be producing about 42 Bcm of gas annually by 2000 and exporting 22 Bcm as LNG. Meanwhile, the so-called Gulf South Asia Gas Project, sponsored by various foreign companies, is trying to drum up interest in building a 20-Bcm per year pipeline from the North field to Pakistan with an overland segment across the UAE and an offshore section along the Iranian coast.

Abu Dhabi has proven gas reserves of 5,380 Bcm. LNG exports in 1995 amounted to 6.8 Bcm. Customers include Belgium, France, Spain and Japan.

Oman's proven gas reserves are minor compared to those of Qatar and Abu Dhabi. Nonetheless, the Omanis see themselves as future exporters of LNG and maybe also of piped gas. In October 1996 Oman signed an agreement with Korea Gas Corporation to deliver the LNG equivalent of 5.7 Bcm of gas per annum for 25 years starting in 2000. Negotiations with the Petroleum Authority of Thailand on deliveries of 3 Bcm per year are at an advanced stage. As for piped gas, Oman signed a memorandum of understanding with the Indian government in 1993 to build a gas export pipeline to India with an annual capacity of 10 - 20 Bcm. Water depths along the 1,150-km route are up to 3,500 metres, calling for as yet untested technology. Moreover, the Omani authorities in 1997 appeared to lose interest in the project. Such a pipeline, if it proceeded, might not interfere directly with Turkmenistan's plans for exporting gas to Pakistan, but could, as a first gas link between the Gulf and the Indian subcontinent, negatively affect perceptions of the long-term competitiveness of Central Asian gas in South Asian markets. India has also requested that the Omanis examine the possibility of sourcing gas from Abu Dhabi and other neighbours as a supplement to Omani supplies.

In 1995 Libya exported a total of 1.5 Bcm of gas to Spain, all in the form of LNG. It could become a more significant competitor in European and possibly other markets. In 1996 the Libyan Government and Agip agreed to build a pipeline from Libya across the Mediterranean to Sicily and the Italian mainland. Exports of about 8 Bcm per year could be sent via this line by 2000 or shortly thereafter. With proven reserves of over 1,300 Bcm, Libya has the geological potential to increase exports to this level and beyond. As an LNG exporter, Libya has been hampered by the absence of a liquefied petroleum gas extraction unit at its existing liquefaction plant at Marsa el-Brega, meaning that customers have had to fraction the product elsewhere. The plant is being upgraded and equipped to deliver normal LNG corresponding to 4.5 Bcm of gas per year.

Egypt does not yet export gas, but after a series of discoveries off the Nile delta and in the Western Desert, proven reserves are now reported at 850 Bcm. The country's r/p ratio is approaching 60 years, and proposed export schemes abound. Egyptian authorities and foreign companies holding development rights in the country have for years pushed a plan to build a pipeline to Israel and onward to Lebanon, Syria and Turkey, although the so-called "Peace Pipeline" lost much of its shine after the onset of clashes between Palestinians and Israeli troops and an Arab League decision to suspend normalisation of relations with Israel. Other companies wishing instead to build a gas liquefaction plant near Port Said to export LNG directly to Turkey have gradually gained the upper hand. In 1996 these interests and Botas signed a memorandum of understanding on LNG exports of 10 Bcm per year from 2001. The originators of the Peace Pipeline concept have responded by proposing a sub-sea line from Port Said to Iskanderun on the Turkish Mediterranean coast.

Nigeria's proven gas reserves are on the same order of magnitude as those of Norway and the UK taken together, i.e., around 3,500 Bcm. Nigerian LNG has been expected on the market for several decades, but due to (among other things) the terms offered by the Nigerian Government and financial hurdles related to the poor state of the Nigerian economy, it took a consortium of foreign and Nigerian companies until late 1995 to decide to go ahead with a project to build a two-train LNG plant on Bonny Island. Construction began in early 1996, and production is scheduled to start in 1999. The company set up to implement the project has supply agreements with Turkey, among others.

Asian competitors

Asian gas exports are mainly in the form of LNG. Indonesia supplies 40% of Japan's gas needs and more than three quarters of Korea's and Taiwan's. The outlook for Indonesia's LNG exports could have a significant impact on Japan's and Korea's interest in projects to make Central Asian gas available to East Asia.

Indonesia's proven gas reserves of 3,520 Bcm and 1996 production (net of re-injection) of 69.4 Bcm provide for a comfortable r/p ratio of 50 years. But key producing fields are in decline and untapped reserves are located far from existing infrastructure. Indonesia aims to have all its long term LNG contracts extended and to participate in the supply of new markets. It hopes to defend its share of world LNG trade by developing several large projects, in particular the giant Natuna field.

Malaysia, Brunei and Australia are the other significant Asian LNG exporters. Their combined proven reserves amount to almost 6,000 Bcm. Their combined gas output in 1995 was 67 Bcm, with LNG exports the equivalent of 31.2 Bcm. Customers are Japan, South Korea, Taiwan and Singapore. These exporters all have some spare capacity. Moreover, Australia and Malaysia have projects under evaluation that could further increase gas production and LNG supply.

PROSPECTS FOR LNG AND LPG EXPORTS

Prospects for exports of liquefied natural gas (LNG) from Central Asia and Transcaucasia are probably more limited than those for natural gas exports via pipeline. This is because

- There are currently no sea ports with LNG export terminals or liquefaction facilities in the region. (The closest re-gasification plant in the vicinity of the Caspian region is located in Marmara Ereglisi, near the Turkish Straits. A new re-gasification plant is being built in Revithoussa, Greece and there are plans to construct an LNG terminal at Constantza, Romania.)

- LNG exports require large gas reserves to support the required large infrastructure investments for 20 or more years, and gas reserves in the region may be insufficient to support such massive investments.

- Since LNG is typically shipped on large tankers of over 100,000 cubic metres of capacity, gas probably would have to be shipped first by pipeline to deep-sea ports in Turkey, Pakistan or India before being liquefied and shipped by tankers to more distant markets.

- There are environmental considerations regarding LNG shipments via the Turkish Straits.

- Many potential markets for Caspian gas are located within a relatively short distance from the region, favouring pipelines over LNG carriers.

- Any LNG scheme from the Caspian would have to compete not only with pipelines but with established LNG schemes; in particular, there would be intense competition from cheaper and relatively underutilised Middle East gas resources.

The prospects for liquified petroleum gas (LPG) exports from the region seem slightly better than those for LNG. Most LPG produced in the region is currently flared, though some foreign companies involved in production at the Azeri field offshore Azerbaijan are studying the viability of selling the product.

Caspian LPG could be transported by rail to one of the Black Sea ports. At present, the only port in the region offering LPG capability is Yuzhnoye (Ukraine), though Turkish LPG distributor Aygaz plans to open a 5-kt per year LPG terminal at the Georgian port of Poti. The latter would allow users to ship Azeri LPG to Turkey and possibly to points beyond. Aygaz also plans to increase storage capacity to around 18 kt by 2003. The terminal by then would have an unloading capacity of 120 railcars per day and an annual throughput of 1 Mt. A plan to build an LPG terminal in Russia's Black Sea port of Temryk appears to have stalled.

LNG Trade

Some 20% of the world's marketable gas production is traded internationally. Of this, about one quarter is shipped as liquefied natural gas (LNG). When cooled to -160°C, natural gas turns into LNG, which can be transported in insulated ocean-going tankers to specialised receiving terminals, where it is returned to a gaseous form and distributed as natural gas to end-users.

Traditional LNG projects are characterised by large capital costs, relatively long lead times, and long-term commitments between buyers, transporters and suppliers, with 20-year or longer contracts as the norm. This implies that large reserves are required to support LNG projects.

A typical grassroots LNG project supplying the equivalent of 6 Mt/year of LNG (1 cubic metre of liquid is equivalent to 0.45 tonnes, or to 570 cubic metres of natural gas) may cost as much as $5-10 billion. Investment in liquefaction usually accounts for 25-35% of the overall capital cost. Investment in new specialised ships can amount to 15-25%, depending on distance and number of vessels required. Receiving terminals account for about 5-15%.

Generally, the economic balance point between a pipeline and LNG shipping shifts to LNG for distances greater than 3,000 km, although this can vary depending on a host of other factors. LNG shipping provides flexibility to sell to multiple destinations, though the number of receiving terminals is limited. In 1996 world trade in LNG involved 23 country-to-country "flows" between 11 export terminals and 35 import terminals. The largest number of receiving terminals is in Japan, which meets around 10% of its energy demand in form of LNG imports.

Between 1975 and 1996 the LNG business grew from 10 to 73 Mt/yr. Southeast Asia currently accounts for three-quarters of the international LNG trade. Most of the remaining LNG shipments are to Europe, where the Mediterranean region, especially Turkey, is one of the most attractive and rapidly developing LNG markets.

INVESTMENT FRAMEWORK

It is useful to keep in mind the context in which the Central Asian and Transcaucasian countries are developing their investment frameworks. Tasks faced by the countries include:

- introducing market economies after more than 70 years of socialism and a breakdown in established industrial and logistical patterns;
- coping with a disintegration of trading relationships, a sharp fall in economic well being, and high inflation;
- building up a skilled caste of administrators and legal professionals to suit new economic and political conditions and to replace those who have emigrated or left for more lucrative careers in the private sector; and
- introducing the rule of law.

In the circumstances of the new republics, urgency has often outweighed thoroughness of consideration. As a result, laws can be unfinished in detail, ambiguous and often amended.

OPPORTUNITIES FOR PRIVATE RISK INVESTMENT IN THE OIL AND GAS SECTOR

The four countries covered by this survey inherited a situation in which all significant economic activity was in the hands of industrial monopolies. Except in Kazakstan, state companies maintain a monopoly – or at least a dominant position – in the oil and gas sector, although the degree of vertical integration differs. In Turkmenistan, one entity controls all oil and gas production, refining and distribution. Refining and production for the internal market are also integrated in Azerbaijan and Uzbekistan, though there is a market in oil product distribution and supply in which the state company competes. In Kazakstan the previous state companies have been broken up and transferred into commercial entities, many of which have been privatised.

There is no legislation or administrative controls requiring state entities to make a profit or preventing cross-subsidisation. As a result, if state entities in the oil and gas sector were competitively motivated, they would probably be able to drive private competitors out of business in any of the sub-sectors. It may be more appropriate in many cases to regard these entities not as commercial enterprises but as executive arms of the government, aiming not at profit but at meeting defined physical requirements. This situation can colour their behaviour toward private investors, which they often regard not as entrepreneurs but as contributors of finance and technology needed to achieve those requirements. The state companies thus generally co-ordinate and co-operate with, rather than compete with, the private sector.

It is often difficult to distinguish between the roles of the state companies and of government departments, though it can usually be assumed that all decisions of note regarding major foreign investment in the oil and gas sector in the four countries are cleared at the highest governmental levels.

Activities open to all qualified companies

Because the monopoly structure in most energy sub-sectors is unchallenged, legal protection for monopolies is rare. This leaves several types of risk investment opportunities open in principle to private investors, including foreign ones.

In theory, an investor may participate in a free, competitive market in which he acts as entrepreneur both in developing a product and a market without needing to contract with the government or with state companies that may become his competitors. In practice, in the oil and gas sector this is usually limited to oil product retail. There are a few examples in the provision of oilfield services, but joint ventures are more common in that industry, as they also generally are in oil-field equipment manufacturing.

Licensed activities

A number of sub-sectors are open to licensing or franchising by the State, including oil and gas production. Licences must be agreed with the government, but (except in Kazakstan) are usually negotiated with an appropriate state enterprise.

Choice of territory to be licensed hitherto has almost always been made by the government in all four countries, though private companies are not legally precluded from proposing acreage. It is not always clear in each country whether state or former state entities have priority rights to territory outside their current fields.

In Kazakstan, time-limited franchises have also been awarded, for example in running the gas transmission systems.

Joint ventures

Investors may form joint ventures with state companies. Joint ventures are arrangements under which a state enterprise and a private (usually foreign) venturer invest stated amounts of capital, which can take various forms, including money, intellectual property, or (especially in the case of a state enterprise) physical assets and rights to land. The partners share the risk and reward of the venture in proportion to the capital contributed. The procedures for taking decisions, making further contributions of capital, withdrawing from or winding up the venture, etc., are defined in the venture agreement. In practice, the amount of control the venturer has over the production process and market and production risks are negotiable and can vary greatly. At one extreme, JVs can be little more than contracts for the procurement of goods or services with no risk. This is often the approach used for the rehabilitation of existing facilities such as oilfields or refineries. At the other extreme, the venture may be akin to a production sharing agreement (PSA), with the venturer taking the production risk in relation to his share of the product (and possibly the state enterprise's share as well) and having complete title to that share, along with the attendant market risks.

Purchase of privatised assets

In Kazakstan, most state energy companies have been converted into joint-stock companies, and privatisation is taking place on a project-by-project basis. In the other three countries, energy sector privatisation is patchy or non-existent outside the oil product retail sector.

LEGAL CONTEXT FOR INVESTORS

Outside the limited area of petrol distribution, most private investors in the oil and gas sectors of the four countries have been foreign. (Only Kazakstan recognises the possibility of national private investment in upstream operations.) All four countries provide for international agreements to override domestic law, have ratified the Energy Charter Treaty (see below), and have concluded bilateral investment protection agreements which specify certain standards of assurance for foreign investors. Following the practice inherited from the Soviet Union, those assurances have found expression in foreign investment laws rather than in abstention from legislative and administrative action that contradicts them.

It is often difficult to obtain the texts of laws in the countries covered by this study, especially in languages other than the local one or Russian.

Standard assurances for foreign investment

Standard assurances for the protection of foreign investments are set out in the Energy Charter Treaty (ratified by all four countries covered by this study) and in various bilateral investment protection agreements. They are also provided for in the laws of all four countries, though with some variations:

- **National treatment:** only Kazakstan does not explicitly provide that the legal treatment of foreign investors may not be less favourable than that accorded to national investors, with stated exceptions.

- **Compensation for losses:** Kazakstan, Uzbekistan and Azerbaijan provide that, in the event of losses caused by wars, civil disturbances, etc., foreign investors will receive compensation at least as favourable as that granted to domestic investors, and will get full restitution or compensation if their assets are requisitioned or unnecessarily destroyed or damaged by government authorities. Turkmenistan provides the latter assurance.

- **Expropriation:** Turkmenistan and Uzbekistan ban all expropriation of foreign investments. Azerbaijan and Kazakstan provide that investments only may be nationalised or expropriated for purposes in the public interest, under due process of law, and on payment to their owners of prompt, adequate and effective compensation.

- **Transfer of profits:** in all four countries foreign investors are assured of the right to transfer returns and other investment related payments.

- **Key personnel:** only in Azerbaijan may the government deny the right to foreign investors to employ expatriate staff, although there have been no reported cases of this happening in practice.

- **International arbitration:** only Kazakstan appears to grant an unfettered right to the foreign investor to take an investment dispute with the government to international arbitration. The other three countries make this right conditional on it being expressed in the relevant contract with the government or its representative.

Additional guarantees

The foreign investment laws for all four countries allow for additional privileges to be granted to foreign investors. Generally, further privileges may be accorded for investments in defined priority sectors and regions, usually in the form of decreased taxes and import duties. However, such priority sectors usually do not include the oil and gas industries. This type of privilege is generally discouraged by the IMF. Moreover, it may be a deterrent to the development of domestic private investment.

All four countries also protect foreign investments against future changes in legislation that worsen the economic conditions for projects for a period of ten years after such changes or, in the case of Kazakstan, for the length of the investment contract made with an authorised state agency. However, the extent of such guarantees is not always clear and may not have been fully considered. The Kazak government specifies that it would not cover defined changes such as more stringent environmental standards; in such cases, compensation would be paid instead.

Petroleum exploration and production regimes

In all four countries, as in many OECD ones, the state is the sole owner of subsoil resources, including oil and gas. The Central Asian and Transcaucasian countries inherited laws on the subsoil from the Soviet Union and are at various stages of amending them. Turkmenistan has enacted comprehensive petroleum licensing legislation, and Kazakstan has introduced several Presidential Decrees on this subject. In Uzbekistan, the laws on Concessions and on Subsoil empower the Cabinet of Ministers to establish procedures, terms and conditions for allocating areas to foreign investors in oil and gas exploration and production. More comprehensive legislation is under preparation with aid from the World Bank. Although Azerbaijan still relies on the old Soviet law governing the exploration and production of hydrocarbons, foreign investors may acquire exploration and production rights under the Law on Protection of Foreign Investments, providing they have signed concession agreements with the government and that those have been approved by parliament.

All four countries regard competition as the normal way of awarding licences. Licences are awarded after a contract has been agreed between the foreign investor and either a government department in Kazakstan and Turkmenistan or a state oil enterprise in Azerbaijan and Uzbekistan. Final formal approval of licences is by the President in Kazakstan and Turkmenistan, and by parliament in Azerbaijan. The detailed terms of a PSA are contained in the contract, though they may also be summarised in legislation.

Non-negotiated terms include the general rights and obligations of the licensee, such as use of land, good oilfield practice, environmental requirements (including rehabilitation of land) and period of validity of the licence. The work programme and the main financial payments other than profits/income tax are negotiated and specified in the contract. The latter include the share of "profit oil" going to the State (or its enterprise), royalty, bonuses on signature, commercial discovery and various levels of production, and annual rentals. A negotiated proportion of the annual oil production is set aside to repay the licensee's costs until they have been recovered. The licensee is exempted from all other taxes (Azerbaijan), other profits and property taxes (Turkmenistan) or from all taxes except those named (Kazakstan). The level of profits tax is “grandfathered” (i.e., remains the same) for the duration of the licence.

Notable non-fiscal features of legislation regarding petroleum contracts include the following:

- Turkmenistan and Uzbekistan give the government pre-emptive purchasing rights if the public sector share of oil is insufficient to meet internal demand. Kazakstan reportedly has a similar provision;
- Azerbaijan (Socar) has a right to all associated gas. Turkmenistan has formally foregone such a right;
- Kazakstan and Turkmenistan have national procurement requirements, providing the national supplier is competitive. Turkmenistan also requires that investors train Turkmen staff;
- Turkmenistan’s petroleum legislation covers trunk pipelines as well as production, and envisages a third party access system;
- Turkmenistan has a sophisticated system for providing, over time, for the costs of abandonment;
- in Turkmenistan and Uzbekistan, consent is needed to assignment; in Kazakstan, no consent is needed.

Little is publicly available on the terms of individual joint ventures. In Kazakstan and Turkmenistan they are subject to the petroleum legislation, though detailed terms are in private contracts with state entities. In Kazakstan they are subject to a graduated excess profits tax levied on internal rates of return above 20% (intended to equalise the fiscal terms with those of PSAs).

Private companies express a preference for PSAs. However, for a number of reasons, some of the advantages claimed for PSAs do not necessarily apply in the countries under review. For example, there is provision under the foreign investment laws of all four countries for protecting foreign investments against adverse changes in tax or other laws (though usually for 10 years rather than the life of the licence). Moreover, in Kazakstan and Turkmenistan, provision is included to achieve equality of taxation between PSAs and JVs. In Azerbaijan, the gross taxation is negotiated between the foreign licensee and Socar, whether the contract form is a PSA or JV.

Independent arbitration

The foreign investment legislation of all four countries provides for a possibility of international arbitration in case of a dispute between an investor and the State arising from the investment. However, this right must be enshrined in the contract governing the investment. In Turkmenistan and Kazakstan this is echoed in the petroleum laws. The Energy Charter Treaty provides investors from other Parties to the Treaty the right to take to international arbitration any disputes with the State arising from their oil and gas investments.

Land

At the dissolution of the Soviet Union, all land belonged to the State. It still does in Turkmenistan and Uzbekistan. In general, property laws in the region are complex. Following is a brief summary for each country:

- **Kazakstan:** land may be owned by nationals; foreigners may own only residential land and land allocated for development. Other land may be provided for permanent use to nationals but for foreigners only on the basis of a lease limited to 99 years;
- **Azerbaijan:** foreign natural and legal persons may not own land. Joint ventures with both national and foreign participation may obtain land for permanent use, but only from the State, not the current user;
- **Turkmenistan:** foreigners may apparently lease land only if no nationals wish to lease it on the same terms;
- **Uzbekistan:** land, other than that attached to buildings (which can be privatised and therefore presumably owned) may be given only for temporary use. Nationals may lease it from the local authority; foreigners only from the Cabinet of Ministers.

Regarding the exploration and development of oil and gas under a JV, the state enterprise partner is likely to make the necessary land rights available as part of its contribution to the venture's initial capital. Under PSA legislation in Kazakstan and Turkmenistan, the licensee is guaranteed all land rights (but not ownership) needed for the licence activities, and the public sector partner accepts the obligation to achieve that result with the local authorities. The same result is achieved in the individual PSAs negotiated by Socar in Azerbaijan. Uzbek legislation specifies property and plots of land as objects which can be provided to foreign investors as part of hydrocarbons concessions. All rights to land and to immobile equipment on the land revert to the state at the end of the licence period.

The license period in Azerbaijan is a maximum of 5 years for exploration and 30 for production; in Turkmenistan, 10 for exploration and 25 for production; in Uzbekistan 15 in aggregate. In Kazakstan, licences and associated rights to land can be freely assigned; in Turkmenistan, consent is needed for assignment.

Incorporation

In all four countries, foreign-owned companies follow procedures different from those followed by domestic investors for incorporation or registration. However, the differences seem to derive from different circumstances rather than from any discrimination. It is also unclear whether a foreign company takes its nationality from the country where ultimate control lies or from that in which it is incorporated.

Taxes

The main taxes affecting investments in the oil and gas sectors are: profits tax, value added tax (VAT), excise taxes, import and export duties, and property tax. The standard rates for the four countries are shown in the following table:

Table 1 Selected taxes affecting investments in the oil and gas sector

Tax	Azerbaijan	Kazakstan	Turkmenistan	Uzbekistan
Profits	25-35%	30%	25%	20-37%
Withholding	15%	15%		20%
VAT	20%	20%	20%	18%
Excise on oil products	24-57%	yes	55-60%	yes
Export duties on oil	*			
Property tax	yes	0.5%	yes	3%
Natural resource tax			22%	

* 70% of difference between home and export price, but not on crude oil exported by a foreign partner in a JV or PSA.

Various privileges are available for foreign investors according to the proportion of a joint venture's capital they subscribe and total capital. Privileges may also be available for investments in special regions, those exporting a large portion of their production, reinvesting profits or investing them in other activities in the host country, or investments in government priority industries.

Accounting

The Central Asian and Transcaucasian countries inherited the Soviet accounting system, which was designed for a planned economy and not suited for determining the financial position of companies according to western standards. All four countries are currently in the process of replacing the old Soviet accounting system with generally accepted western accounting principles. In Kazakstan, larger enterprises started to employ a new western-based system in 1996. Turkmen legislation is precise in requiring oil and gas producers to follow international accounting practice for petroleum operations but to follow Turkmen rules regarding salaries and social costs.

Pipeline regulation

Only Kazakstan has constructed a common carrier regime for gas and crude oil transmission pipelines. In the other countries, the assumption appears to be that, while government and the state oil company are very much involved in route planning and negotiations of new export pipelines, private producers will be expected to provide much of the finance. Although private investors will have rights of ownership and carriage, the problem of how to treat new producers has not been addressed in detail. However, Turkmenistan provides such producers with a right to carriage on non-discriminatory terms, providing there is spare capacity.

Price controls

Except in Kazakstan, internal prices for oil products and gas are controlled. In practice they appear to be derived on a cost-plus basis, although the costs used tend to be average costs, may not fully take inflation into account, and usually do not fully reflect capital costs. In Uzbekistan, oil product prices have been raised to world market levels.

A problem in all four countries is the lack of sufficient competition needed for effectively determining market prices. This is general throughout the world in relation to gas distribution and to services rendered by both oil and gas transmission pipelines. For a transitional period, it also will affect refining and oil product marketing until monopolies inherited from the Soviet Union are dissolved. Even then it may take time for strong competition to emerge in the rural areas of such sparsely populated countries as Kazakstan and Turkmenistan.

Social obligations

In the Soviet Union, state owned companies were expected to provide retirement benefits and health care for their employees, as well as housing, education and even holidays. Progress in relieving employers from such social responsibilities has been slow, and private investors may be expected to pick up some social burdens that would be the responsibility of the state in most western countries.

Privatisation

Each country has general enabling legislation on privatisation establishing rules, procedures and institutions involved. These often differ according to the size of the asset to be privatised and the sector. Before a large enterprise is privatised, it may be restructured into smaller joint-stock companies to reduce the degree of vertical integration and to break up monopolies.

It is common in each of the four countries for the staff and workforce of a company being privatised to receive a portion of the shares free or on preferential terms. Except in Uzbekistan, citizens or permanent residents may also be granted vouchers which they can use in lieu of money to purchase shares in particular industries or in funds set up to hold a portfolio of privatised shares. Citizens may also be given advantages in the purchase of minor privatised assets such as petrol stations. There are no constraints on the resale of privatised shares, although stock markets are not well developed.

In all four countries, foreign investors, both individuals and corporations, may acquire privatised assets. However, Azerbaijan has a complex system requiring foreign investors to pass through an extra step which may amount to a minor financial surcharge on foreign investors. Kazak legislation requires privatisation to be implemented through competitive bidding. That appears to be the practice in Turkmenistan and Uzbekistan as well, apart from minor assets such as petrol stations.

With the exception of minor assets, the situation varies greatly in the four countries with regard to privatisation in the energy sector. Kazakstan has converted most of its energy sector enterprises into joint stock companies and has privatised a number of oil and gas production associations and refineries. The oil product distribution network and 98% of petrol stations were privatised by the end of 1996. It is envisaged to retain state control over the oil and gas pipeline systems and over gas distribution, although management of the gas transmission system has been devolved to a foreign investor.

In Azerbaijan, energy enterprises have been transformed into state joint stock companies and placed on a list for possible privatisation via staged reductions in the State's share holding.

However, privatisation in the energy sector still must be approved by the President, who will presumably also decide at that time on the admission of foreign investors. So far privatisation of such enterprises does not appear to be on the government's agenda.

Uzbekistan has included enterprises and organisations of the energy sector on a list for eventual privatisation. Over 80 oil and gas enterprises have been converted into corporations, and around half of the country's petrol stations have been auctioned off. However, the government expects to retain a majority share in the major energy enterprises for the foreseeable future.

In Turkmenistan, entities in the energy sector are excluded from divestment and privatisation, except in the case of some related construction organisations.

INVESTMENT CONTEXT BY SUB-SECTOR

Oil and gas production

The largest opportunities for private sector investment in the four countries covered by this study are in oil and gas production. The current legal situation has been described above. In joint ventures with state-owned oil companies in Kazakstan and Azerbaijan, investors put their own equity capital at risk.

Kazakstan has made over 60% of known recoverable reserves available to foreign companies and joint ventures with foreign participation, and the share of oil produced by joint ventures in that country reached almost one-third in 1997. Azerbaijan had concluded over nine major development projects with foreign investors by the end of 1997, mainly on a PSA basis offshore, and on a JV basis for the rehabilitation of fields onshore. In both Turkmenistan and Uzbekistan, foreign companies have been involved in exploration and field developments and workovers; in the latter, this has been on a contractual basis without a clear equity interest in the fields.

Petroleum storage and transmission

A number of foreign private companies, with or without exploration or production interests, are promoting particular pipeline schemes. In other cases consultants have been hired to perform feasibility studies. Both Kazakstan and Azerbaijan expect private licensees to bear the brunt of expenditure on new export pipelines at their own risk. Turkmenistan specifies that pipeline owners can be licensees or other private persons. Considerable expenditure is also planned on internal gas and oil transmission lines and gas storage facilities. However, only in Kazakstan, where a franchise for managing and upgrading the gas transmission system has been awarded to a foreign company, has there been significant private participation in such projects.

Oil refining

Considerable investment is planned in upgrading the oil refining sectors of the four countries examined in this study. Although many upgrading projects involve foreign contractors, most appear to be turnkey or construction projects, with no indication that investors will be given an equity interest. A notable exception is Kazakstan, where two refineries are run by private investors, including one on a contract basis.

Oil product distribution

Distribution (other than major terminals) and retail of oil products have been largely privatised in all four countries. Most privatised petrol stations are in the hands of domestic investors. However, the state refinery companies are competing in the same market and there are no formal rules to prevent them from abusing their refinery monopoly powers.

Oilfield equipment and services

The capacity to supply oilfield equipment and services in the region is well below prospective demand. Moreover, the logistics are not easy for importing large equipment. There are generally no impediments to establishing equipment and servicing investments. Where there are relevant state companies, they appear anxious to form partnerships. Given their access to land, installations and skilled workforces, such enterprises may be attractive partners for foreign investors. (See also the Azerbaijan chapter.)

ENERGY CHARTER TREATY

In all four countries, international treaties which the legislatures have ratified have direct effect without the need for further legislative processes to align domestic laws with the treaty terms. All four have legislated that, in the event of a conflict between domestic legislation and the provisions of such treaties, the latter take precedence. Azerbaijan, Kazakstan, Turkmenistan and Uzbekistan have all ratified the Energy Charter Treaty (Treaty), which came into force in April 1998 (with provisional effect until that time, to the extent that it did not conflict with domestic legislation).

Part III of the Treaty covers the promotion and protection of investments by entities of other Contracting Parties, which include all OECD countries except New Zealand, the Republic of Korea, Canada and the United States, as well as many non-OECD countries. It applies to all investments in "economic activity in the energy sector", which is defined as "an economic activity concerning the exploration, extraction, refining, production, storage, land transport, transmission, distribution, trade, marketing or sale of energy materials or products". This includes such services as construction of energy facilities, prospecting, consulting, management and design. The Treaty requires signatory governments to:

- fulfil any obligations entered into with an investor of another Contracting Party;
- treat the investments of an investor of another Contracting Party no less favourably than those of its own investors or the investors of any other country. (A supplementary Treaty, to be signed in 1998, will determine the conditions under which this principle will also apply to the admission of new investments by investors of other Contracting Parties);
- permit investors to employ key personnel of their choice, regardless of nationality, so long as such personnel have work and residence permits;

- pay compensation for any losses suffered by a foreign investor in time of war or civil strife at least as fully as for losses suffered by the country's own nationals;

- pay prompt, adequate and effective compensation for any assets expropriated; and

- allow a foreign investor freely to transfer out of the country, in convertible currency, capital invested and any associated earnings.

The Treaty does not require its Contracting Parties to encourage equity investment, reform its monopolies or to privatise. However, it does contain other provisions of substantial value to investors in the oil and gas sub-sectors, including the following:

- Countries are required to have and enforce laws addressing anti-competitive practices.

- Transit states must facilitate transit; not impose more onerous terms on transit traffic than on goods originating in or destined for their own territory; not impede the construction of new transit capacity if access to existing capacity cannot be gained on commercial terms; and refrain for up to 16 months from interrupting a transit to enforce a claim in a dispute.

- Contracting Parties are required to publish laws and administrative rulings of relevance to the matters covered by the Treaty and to set up inquiry points for potential investors and other interested parties.

- Contracting Parties are obliged to ensure that state entities follow the non-discrimination rules in the sale and provision of goods and services to foreign investors, and may not require a state enterprise or monopoly entity to act against the Treaty rules. Similarly, Contracting Parties must do all they reasonably can to ensure that regional and local governments observe the provisions of the Treaty.

- Trade in energy materials and products involving a Party to the Treaty that is not a party to the General Agreement on Tariffs and Trade (GATT) must in general follow GATT rules except in relation to public procurement and fixing tariffs, as well as in some other minor matters. An amendment has been prepared to apply the Treaty's trade rules to specified energy-related equipment and to substitute the outdated GATT rules with the relevant rules of the World Trade Organisation.

The four countries covered by this survey, as Treaty signatories, still have grace periods for a few provisions concerning, in particular, competition, before they must fully implement them. On the other hand, each already had introduced legislation to implement some of the more important requirements before the Treaty was signed.

An important and far-reaching feature of the Treaty is its provisions for dispute resolution. Separate articles cover inter-state disputes and those between states and foreign investors. The latter have an unequivocal right to take a dispute about provisions of the Treaty to international arbitration, including, in the case of the four countries covered here, over observance by the state of any obligations that it has entered into with an investor or his investment. The Treaty provides that the awards of arbitration shall be final and binding and obliges Contracting Parties to carry out the awards without delay and to provide for the enforcement of such awards within their countries.

MARINE TRANSPORTATION IN THE CASPIAN AND BLACK SEAS AND THE TURKISH STRAITS

THE TURKISH STRAITS

Currently, most oil exported from the Caspian region goes via the Russian Black Sea port of Novorossiysk. Several oil pipelines being built from the region also terminate on the Black Sea. From there, most of the oil passes through the Turkish Straits to reach world markets. There is concern that future oil exports from the region could significantly increase tanker traffic through the Straits, thereby raising the chance of a serious accident that could pose environmental and safety threats, as well as disrupt the flow of oil from the region.

The Turkish Straits comprise the Istanbul Strait (Bosphorus), the Sea of Marmara, and the Canakkale Strait (Dardanelles). The 19 nautical miles of the Istanbul Strait contain four turns of more than 45 degrees, and at one point the passage narrows to only 700 metres. The Strait passes through Istanbul (population 12 million) and constitutes one of the busiest waterways in the world.

Some 50,000 large ships of over 1,000 deadweight tonnes passed through the Straits in 1997. About 15% of these were estimated to contain hazardous cargoes, including oil. In addition, more than 1,500 local passenger ferries cross the Straits daily.

The total number of foreign ships transiting the Straits has risen significantly in recent years, especially between 1994 and 1997. This largely has been due to newly emerging trade patterns resulting from the breakup of the Soviet Union and the opening of the Main-Danube canal, creating a link between the Black Sea and the North Sea. However, the number of tankers and the amount of oil passing through the Straits does not appear to have risen significantly during that period.

Table 1 Number and tonnage of ships passing through the Strait of Istanbul

Year	Number of ships	Net tonnage (million tonnes)
1938	4,500	7,500
1985	24,100	105,500
1996	49,952	156,057

The increase in overall traffic coincided with a rise in the number of accidents in the Straits. Between 1984 and 1994 there were approximately 20 major collisions.[1]

New rules and recommendations for the Straits

Turkey has implemented a number of measures to improve safety, but the government is limited in its ability unilaterally to change regulations regarding international commercial traffic in the Straits because of stipulations of the Montreux Treaty of 1936. Although Turkey has been given responsibility for implementing the Montreux treaty, the Treaty says in part, "*merchant vessels shall enjoy complete freedom of passage and navigation in the straits, by day and by night, under any flag and with any kind of cargo, without formalities. No taxes or charges shall be levied by the Turkish authorities...Pilotage and towage remain optional.*"

In 1994 Turkey presented recommendations to the International Maritime Organisation for increasing safety in the waterway. The IMO, which noted that navigation through the Straits presents "an increasing potential risk to shipping, safety, the environment and the local community," introduced new traffic separation schemes for the Turkish Straits, effective 24 November 1994. It also issued a set of routing measures which contains further rules and recommendations for navigation through the Turkish Straits. These include:

- requiring ships unable to comply with the traffic separation scheme (usually because of their large size) to inform the Turkish traffic authorities of this inability well in advance;
- granting the Turkish authorities the right temporarily to suspend two-way traffic and regulate one-way traffic in order to ensure the safe passage of vessels which cannot comply with the scheme;
- recommending that ships report their cargo and use a qualified pilot while navigating the Straits (only about 20% of vessels report their cargoes and only 33% use pilots); and that ships with a maximum draught of 15 metres or more and those over 200 metres in overall length navigate the Straits in daylight. (Turkey has made these recommendations mandatory for Turkish-flagged vessels, which make up an estimated 20% of traffic through the Straits.)

Since the introduction of these measures and recommendations, the number of accidents in the Straits has decreased significantly, from 25 in 1993, to 2 in 1996. Nevertheless, there have been complaints by some parties about delays caused by closing the Straits to two-way traffic during the passage of large vessels. Part of the problem is that there are differing interpretations of what constitutes a vessel "not able to comply with the requirements of the TSS". This is an important issue for oil transit, since the economics of shipping oil generally improve as the size of the ship increases.

Some environmentalists argue that using larger tankers (100,000 dwt and over) increases the chance of a serious environmental accident, due to the potentially large volume that may be spilled, as well as the increased difficulty of navigating such vessels in the Turkish Straits. Others counter that using smaller vessels increases the risk of (smaller) accidents due to the larger number of ships that would be needed to carry the same amount of oil.

1. The most serious accident took place in March 1994, when a freighter and an oil tanker (the Nassia) collided. Twenty-nine sailors died in the ensuing fire, and the 20,000 tonnes of spilled crude continued burning for a week. Another collision, between two tankers, released over 95,000 tonnes of oil, which also caught fire and burned for several weeks.

Table 2 Number of collisions in Istanbul Strait

Year	Number of collisions
1990	43
1991	49
1992	39
1993	25
1994 (first half)*	10
1994 (second half)	2
1995	4
1996	2

* Before TSS (Before 01.07.1994)

The IMO further recommended the installation of a modern Vessel Traffic System (VTS), which could further decrease the risk of accidents. However, a VTS would probably be difficult to finance, since the Montreux Treaty prohibits Turkey from charging foreign vessels fees for using the Straits. Although foreign ships are major users of the Straits and thus would be major beneficiaries of the VTS, some countries are unlikely to approve requisite changes to the treaty if they would result in significantly increased transport costs.

Oil flows through the Turkish Straits

Table 3 Oil transported through the Turkish Straits in 1996 (kb/d)

Transit of FSU (mainly Russian) oil from Black Sea	1,170
Transit of Romanian and Bulgarian oil from Black Sea	70
Transit of oil *into* Black Sea	151
Total oil transported through Turkish Straits	1,391

In 1996 approximately 1.4 Mb/d of crude and products were shipped through the Turkish Straits. By 2010, oil exports from Central Asia and Transcaucasia could be as high as 2.3 Mb/d. Much of this is expected to pass through the Turkish Straits to the Mediterranean. However, a number of things could lessen the overall impact of increased Caspian region oil on the Straits:

- Demand in countries bordering the Black Sea is expected to increase by approximately 0.7 Mb/d, from 1.5 Mb/d in 1996 to around 2.2 Mb/d in 2010. A significant portion of this demand could be met by Central Asian and Transcaucasian oil. Moreover, such oil could also displace some of the oil passing through the Straits from the West.

- Under certain conditions, a decline in Russian oil exports via the Black Sea cannot be excluded. Russian domestic oil consumption will increase with rising economic output. If lack of investment in oil production should continue, this could cause overall Russian output to fall again. Finally, port expansions and pipeline de-bottlenecking in northwestern Russia and the Baltics could increase Russian exports via the Druzhba pipeline and the Baltic States' ports – a move which could be accelerated by cheaper Central Asian/Transcaucasian crude pushing some Russian crude out of Black Sea and Mediterranean markets.

At least two export pipelines for Central Asian oil that would avoid the Mediterranean are being considered: one to China, and another to Pakistan, each of which is planned to have a capacity of 1 Mb/d. In addition, swaps of up to 650 kb/d are being considered by some projects for Iranian oil in the Gulf, although this latter possibility looks unlikely under the current sanctions regime.

Bypassing the Straits

Pipeline routes bypassing the Turkish Straits could help diminish the risk of a serious accident, which, besides causing damage to lives, property and the environment, could impose a bottleneck on the transport of Central Asian/Transcaucasian oil to world markets. In this sense, pipelines bypassing the Turkish Straits would enhance energy security by increasing the number of export options. They would also allow the loading of larger tankers which could not transit the Turkish Straits.

There are two ways of avoiding the Turkish Straits. One is to bypass the Mediterranean completely, for example by sending oil via Russia, Iran, China, or Pakistan; these options are discussed elsewhere. The other is to build a pipeline to the Mediterranean around the Straits. Proposed projects of this sort include the following:

- across Turkey to the Turkish Mediterranean port of Ceyhan, either from Samsun on the Black Sea, or from a point in Georgia or Armenia where it would connect with a pipeline from Baku; (The Ceyhan option with the Baku connection is also one of three routes actively under consideration for transporting peak production from the AIOC project offshore Azerbaijan)
- across Turkish Thrace, from Kiyikoy to Ibrikbana;
- from Burgas, Bulgaria, to Alexandroupolis, Greece, or to Vlore, Albania.

Apart from the Ceyhan option with the Baku connection, all of these alternative bypass routes would involve additional loading and unloading of tankers, with associated costs and environmental risks.

MARINE TRANSPORTATION IN THE CASPIAN AND BLACK SEAS

A number of existing oil and oil product export routes involve tanker movements across the Caspian and/or Black seas. Many such routes are temporary solutions until pipeline transportation is available. This section examines current port and tanker fleet capacities and plans for their expansion. Selected shipping flows and infrastructure are shown in Map 7 at the beginning of this book.

Caspian Sea

Total transfers of crude oil and products across the Caspian, including those from Azerbaijan, were around 7 Mt in 1997. These transfers are constrained by the capacity of ports, which are small, shallow and often poorly equipped, and by the number of tankers. Other limiting factors include storage capacity and means of transportation from ports to markets and refineries. Vessel loading and unloading times can also be a problem. Round trip voyages commonly take 4 - 10 days, though waits of up to 25 days to unload cargoes have been reported.

Current plans by private companies and governments in the region suggest that volumes of crude oil and products shipped across the Caspian Sea could triple to more than 20 Mt by 2000. The bulk of the incremental volumes would most likely be shipped from Aktau to Dyubendi and to northern Iranian ports, the latter being contingent on the fate of swap arrangements with Iran. Implementing such plans will require major modernisation and expansion of several ports, storage facilities and the tanker fleet.

Table 4 Capacity of selected Caspian Sea ports (Mt/year)

	1997	2000 (proj.)
Export capacity		
Kazakstan	5.0	10 - 12
Turkmenistan	1.1	1.1
Import/transit capacity		
Azerbaijan	2.6	10
Iran	3.5	10
Russia	0.5	0.5

Kazak oil exports

Kazakstan's exports beyond the FSU in 1997 increased significantly over those of 1996. In part this was due to the development of marine export routes across the Caspian Sea. Kazakstan shipped an estimated 5 Mt in 1997 via three routes from its port of Aktau. Around 2 Mt was transported by Kazakstan's Tengizchevroil (TCO) joint venture to markets in southern and western Europe via a multi-modal route extending to Georgia's Black Sea port of Batumi. Oil is first sent by rail from Tengiz to Aktau, where it is loaded onto small tankers (5,000-7,000 dwt) sailing to Azerbaijan's Dyubendi terminal near Baku. From there it is transported across Azerbaijan by rail or through the Dyubendi-Dashkil-Ali Bayramli pipeline, and further by rail to Batumi, where it is loaded onto tankers (10,000-50,000 dwt) sailing to the Mediterranean. Transport costs are reportedly US$ 6 per tonne to Dyubendi and an additional US$ 45 per tonne overland to the Black Sea, including handling costs at Batumi. TCO plans to increase such shipments to 3 - 4 Mt in 1998 and to 10 Mt by 2000. To achieve that target, the company will refurbish terminals at Aktau, Dyubendi and Batumi, and expand the fleet of available Caspian tankers and railroad tank cars. In the future TCO's oil may be transported by the AIOC's western pipeline from Baku through Georgia to Supsa, which is to be completed by 1999. There are also plans to create a unified pipeline system between Dyubendi and Batumi by 2000, with an eventual capacity of 7 - 8 Mt/year.

Kazakstan's second major trans-Caspian marine route is a swap arrangement by which the Kazak government has delivered crude to northern Iran for an equivalent amount of Iranian crude lifted by Kazak shippers in the Persian Gulf. According to official Kazak statistics, 70 kt of crude was exported this way during the first half of 1997. There were reportedly no swaps during the second half of the year due to disagreements over crude quality and other technical problems. The swap deliveries to Iran were originally expected to reach around 1 Mt in 1997, and increase to 2 Mt in 1998 and 6 Mt by 2000.

Turkmen oil exports

Turkmenistan exported an estimated 2.9 Mt of crude oil and products in 1997, of which about 0.6-0.7 Mt was shipped across the Caspian Sea from the port of Turkmenbashi (capacity of around 1 Mt/yr) to Dyubendi near Baku. The operation was contracted to Swiss- registered Glencore, which shipped diesel oil and other products from the Turkmenbashi refinery to Azerbaijan for further rail transport across Georgia to the Black Sea port of Batumi.

In November 1997 Caspian Transco began shipping small volumes of Turkmen crude to Baku for further transport to Batumi. The company expects to ship 2 Mt of Turkmen crude via this route in 1998.

Glencore has also shipped Turkmen crude and fuel oil to the northern Iranian port of Bandar Anzali where the cargoes are discharged into tank trucks. Reported volumes for 1997 were one 5,000-t cargo per week, implying 0.3 Mt on an annual basis.

In 1995 the trader Vitol began shipping fuel oil from the Turkmenbashi refinery to the northern Iranian port of Neka. From there product was sent by truck to Bandar Abas. Peak volumes of 25 kt per month in early 1996 reportedly fell to nothing by late 1996, although Vitol's local partner, Iran Marine Industries Co., reportedly continues to provide services in Neka to arriving oil product cargoes.

Azeri oil exports

In 1997 Azeri state oil company Socar reportedly shipped 0.5 Mt of petroleum products to the Russian Caspian port of Makhachkala under a contract with Lukoil, and 1.5 Mt to Iran under a government-to-government agreement. The latter shipments included deliveries of gas oil and kerosene to Bandar Anzali and Nowshahr, and fuel oil for a power station near Neka. Volumes fell during the latter part of 1997, and in December 1997 were running at less than 0.1 Mt per month, roughly half earlier monthly levels.

Port constraints

Total transfers of Kazak and Turkmen oil across the Caspian currently amount to a little over 5 Mt per year. These transfers cannot be increased significantly without expansions to the Kazak port of Aktau and the Turkmen port of Turkmenbashi, which together have a combined capacity of around 6 Mt/year. The unloading facilities at the Azeri port of Dyubendi and the

Iranian ports of Bandar Anzali and Neka are also fully utilised. Dyubendi was expanded in 1997 by 0.6 Mt/year to 2.6 Mt/year in order to allow increased deliveries of oil from Kazakstan and Turkmenistan.

Local shipments of Azeri oil products across the Caspian to Russia's port of Makhachkala and to Iran are also constrained by the unloading capacity of these ports, as well as by loading capacity at Baku. Moreover there are restrictions on the movement of Russian-flagged vessels in Baku.

Overview of selected Caspian oil ports and expansion plans

Baku (Azerbaijan) is designed to export about 4 - 4.5 Mt of refined products annually and is not suited for imports or exports of large volumes of crude oil. It can accept vessels of up to 12,500 dwt with a maximum draft of 12 metres. Baku has three small jetties, each with two berths for product tankers only. The physical condition of one jetty (a wooden construction from late 1800) is considered substandard. Operation of the second jetty is hampered by the rising water level of the Caspian Sea. The condition of the third jetty, which is believed to be used as a lay berth only, is not clear.

Dyubendi (Azerbaijan), where a new terminal increased capacity in 1997 to 2.6 Mt per year, is located about 40 km northeast of Baku. It is used for the transit of oil from Kazakstan and Turkmenistan for exports overland to the Black Sea, as well as for landing Azeri offshore oil. The port contains a purpose-built tanker terminal with three finger jetties, storage tanks and a pipeline connection to the refineries in Baku. The three jetties have two berths each, but only one is currently in working condition. The port is suitable for 7,000-dwt tankers. The US$14 million expansion project conducted by Caspian Transco in 1997 included a new terminal, a pipeline to a railway terminal, a loading system for 20 tank cars and 15 kt of storage facilities.

Aktau (Kazakstan) has a total throughput capacity of around 5.0 Mt/year, which reportedly could be increased with improved vessel turnaround time. The two 15-year old berths and one 30-year old berth are reportedly suitable for 5,000-7,000 dwt tankers. The water depth at Aktau is 7-8 metres. There are plans to refurbish the general cargo port, though not the oil berths, using a US$54 million loan from EBRD and US$20 million from Kazak government sources.

Turkmenbashi (Turkmenistan) has an annual export capacity of around 1.1 Mt, most of which is currently utilised. The port has four berths which can accommodate tankers of up to 7,000 dwt. The maximum draft is 7 metres. There are no plans reported for the port's expansion in the near future.

Neka (Iran) has an estimated annual unloading capacity of 1.5 Mt/year. The port has one berth capable of accommodating oil tankers of up to 4,200 dwt. The maximum draft of 4 metres may have been increased in late 1997 through a dredging operation. Onshore storage tanks can handle some 6,200 tonnes of crude oil and products.

Bandar Anzali (Iran) has an estimated unloading capacity of 1.7 Mt/yr. It is basically a dry cargo port with one berth handling gas oil imports from Baku (shared by a passenger vessel).

The maximum draft in late 1994 was 4.5 metres and the maximum size of tankers served was 5,000 dwt. Substantial investment reportedly would be required to increase throughput and to enable the port to handle crude oil. Proposed investments include a dedicated single point mooring (SPM) tanker berth and new storage facilities. Reversal of an existing products pipeline, or construction of a line to bring crude to a nearby refinery have also been contemplated.

Bandar Nowshahr (Iran) is a small dry cargo port with one berth for occasional small tankers delivering gas oil. The port is not likely to be used for crude oil imports mainly due to a very shallow draft.

Tanker capacity

Table 5 Estimated oil tanker capacity in the Caspian Sea

Fleet	Vessels	Average Size (,000 dwt)	Max. annual vessel oil cap. (kt)[1]	oil shipment by fleet (Mt)[2]
Sea tankers				
Caspian Shipping (Az)	29	5-7.5	5.6	8.1
Iran	6	3	2.7	0.8
Others [est.]	6	3	2.7	0.8
				9.7
Sea/river tankers[3]				
Volgotankers (Rus)	18	2.7-5	3.5	3.1
Lukoil (Rus)	2	2.7-5	3.5	0.4
				3.5
				13.2

[1] Assuming 50% of ships at each end of size range and oil carrying capacity of 90% of deadweight capacity.
[2] Assuming 350 working days, 7 days per return voyage (i.e., 50 trips per vessel).
[3] Assuming these tankers are used full time on trans-Caspian routes and not on Volga-Don.

Available information on numbers of vessels and capacities in the Caspian Sea is extremely limited. Based on various sources, the IEA estimates that in 1997 there were some 60 -65 oil and product tankers in the Caspian with a total carrying capacity of around 250 - 300 kt of oil or products. This gives an estimated maximum transport capacity of about 13 Mt per year, assuming an average return trip of 7 days (which implies minimum delays loading and unloading) and that about 20 sea/river tankers were employed full time on trans-Caspian routes. (Estimated annual capacity excluding the sea/river tankers was about 9.7 Mt.) Total transfers of crude oil and products across the Caspian, including from Azerbaijan, were around 7 Mt in 1997. This suggests that logistical capacities of Caspian ports may have been a limiting factor on deliveries. The condition and availability of the tanker fleet also probably imposed limits.

The introduction of new tankers is difficult due to the land-locked nature of the Caspian Sea, and those brought in via the Volga-Don Canal are limited by the depth of the channel. Both Russia and Azerbaijan have shipbuilding yards on the Caspian that could be used for constructing new vessels, though such yards have seen little investment in recent years.

The Azeri government-owned Caspian Shipping Company, based in Baku, is the main tanker operator in the Caspian Sea. It has 29 sea tankers in the range of 5,000 - 7,500 dwt, with drafts of 4.2 - 5.3 metres. (The company also has five tankers operating in the Black Sea.)

Iran has half a dozen small tankers with a typical capacity of 3,000 dwt. In addition, some local trading companies, including Glencore, have a similar number of small tankers.

Russia's Volgotankers, the major Volga River operator based in Samara, owns a fleet of sea/river vessels able to cross the Caspian Sea (e.g., from Aqtau to Astrakhan) as well as navigate the Volga-Don Canal. (The company reportedly transports 90% of all oil shipped on the Volga River.) Its vessels are typically 2,700 - 5,000 dwt with a maximum draft of 4 metres. The number of Volgotankers in the Caspian fluctuates with demand. In 1997 some 20 ships were in circulation.

Volgotankers plans to add six new oil tankers to its fleet. Lukoil, which currently has two vessels and otherwise charters ships from Volgotanker, plans to build ten sea/river tankers of its own by late 2001. Each will be designed to carry 3.6 kt on rivers and 6.6 kt on the sea.

Volga-Don canal and river system

The mouth of the Volga River is on the Caspian Sea, while the mouth of the Don is on the Black Sea. The two rivers are connected by the Volga-Don canal. This allows limited amounts of oil to be shipped from the Caspian to the Black Sea. The low draft along this route (2.8 - 3.0 metres) limits individual oil cargoes to about 2 kt. In 1997 the KazakTurkMunai joint venture exported around 2 Mt of Kazak crude from Aqtau to Turkey via the Volga-Don canal using sea/river tankers.

A typical trip between Turkmenbashi to the Turkish Black Sea port of Trabzon reportedly takes 15 days, including about 10-12 days on the Volga-Don canal and river system. The Volga-Don system contains a number of check points, and includes one bridge in Rostov that must be raised.

The route was not used by Azeri tankers in 1997 because of differences between Azerbaijan and Russia regarding access to each others' ports and territorial waters.

The traffic on the Volga-Don system is poised to increase when Russia, under an agreement signed with the European Union, reopens this internal water route to foreign ships by 2000. (Fourteen Russian ports on the Baltic and the Caspian seas, the Sea of Azov and the Amur River already have been opened to foreign ships.) To increase shipping, it reportedly will be necessary to substantially modernise the canal as well as the system of shipping locks in the lower stretch of the Don River.

Black Sea routes

The Russian Black Sea ports of Novorossiysk and Tuapse and the Ukrainian Black Sea port of Odessa have a combined export capacity of around 50 Mt per year (1 Mb/d), most of which was utilised in 1997. (Selected import capacity in the Black Sea is discussed below.) Most exports are of Russian oil, although since 1996 all three have handled small volumes of Kazak crude and could provide significant export outlets for future volumes of oil from the Caspian region.

Table 6 FSU crude oil exports via the Black Sea, 1995-1997 (thousand tonnes)

Export point	1H'95	1H'96	1H'97	Annual capacity	Capacity utilisation (%) 1H'95	1H'96	1H'97
Novorossiysk	13,579	15,206	15,891	34,000	79.9	89.4	93.5
Russian Crude	13,579	14,819	15,264				
Kazak Crude	0	387	627				
Odessa	4,039	5,203	5,123	8,000	101.0	104.1	102.5
Russian Crude	4,039	4,323	4,307				
Kazak Crude	0	880	816				
Tuapse	2,359	2,211	2,271	5,000	94.4	88.4	90.8
Russian Crude	2,359	2,201	2,251				
Kazak Crude	0	10	20				

Source: PlanEcon, October 1997

Kazak oil exports

Slightly over 1 Mt of Kazak oil was transported in 1997 via the Russian pipeline system to the Russian Black Sea port of Novorossiysk. Around 50 kt went to the Russian port of Tuapse. Some 3.6 Mt went via pipeline and rail to the Ukrainian port of Odessa, of which 2 Mt was shipped via Odessa to markets in Turkey. A further estimated 2 Mt of Kazak crude was shipped across the Caspian Sea to Baku and then by pipeline and rail to the Georgian Black Sea port of Batumi, and another 2 Mt to the Black Sea via the Volga-Don Canal. Total Kazak shipments to or through the Black Sea in 1997 thus reached about 8.6 Mt, or more than half of the country's gross exports to markets outside the FSU.

Turkmen and Azeri oil exports

Turkmen and Azeri oil exports to or via the Black Sea in 1997 reached a combined volume of around 1.5 Mt, most of which was in the form of oil products (around 0.7 Mt for each country) railed from Baku to Batumi. After including Kazak oil exports, Batumi handled at least 3.5 Mt in 1997, compared to maximum loading capacity of approximately 5 Mt/year.

Proposed export pipelines to the Black Sea

In October 1995 the Azerbaijan International Operating Company (AIOC) decided to split its "early" oil exports between two pipeline routes, both of which terminate on the Black Sea: Baku-Novorossiysk (Russia), which was completed at the end of 1997, and Baku-Supsa (Georgia), which is expected to be ready in 1999. The lines to Novorossiysk and Supsa will each have an initial capacity of 5 Mt per year, with expansions possible in both cases. Since there is only limited spare capacity at the port of Novorossiysk and no oil terminal at Supsa, new terminals are being constructed at both locations.

Production from the AIOC project came on-stream in late 1997. Exports are expected to exceed the capacity of the "early" Novorossiysk and Supsa routes by about 2003. To accommodate increased volumes, the AIOC is evaluating plans to build a third and larger export line, the routing of which is to be decided by the end of 1998. In July 1997 the AIOC narrowed the options for the "main" oil pipeline to the two routes used for early oil, plus a third route to the Turkish Mediterranean port of Ceyhan. One of the advantages of a pipeline to Ceyhan is that it would bypass the environmentally sensitive Turkish Straits. (See also the section on the AIOC pipelines in the Azerbaijan chapter and the section on the Turkish Straits in the present chapter.)

The other major pipeline project that is to terminate at the Black Sea is the Caspian Pipeline Consortium (CPC) line from Tengiz, Kazakstan, to Russia's port of Novorossiysk. The pipeline is expected to be operational around the turn of the century with an initial capacity of 28 Mt per year, to be expanded to 67 Mt per year by about 2012. (See also the Kazakstan chapter.)

Overview of selected Black Sea ports and plans for their expansion

Novorossiysk (Russia) had an export capacity of 34 Mt per year in 1997. In 1994 it prepared a plan to construct a new berth opposite that which currently handles 95% of the port's crude oil exports. The US$60 million project would allow the port to accommodate vessels of up to 80,000 dwt and would reportedly boost the terminal's annual capacity to 50 Mt. Capacity could also reportedly be increased by 3 - 4 Mt by improving delivery through pipelines feeding Novorossiysk. As stated earlier, the CPC is building a new terminal in nearby South Ozeryevka with an annual export capacity of 15 Mt.

Odessa (Ukraine) has an annual export capacity of around 10 Mt. The port has two berths for handling crude and two for products. A fifth berth was being refurbished in 1997. Maximum draft is 11.5-12.0 metres, allowing for vessels of up to 80,000 dwt.

Tuapse (Russia) has a nominal annual throughput of around 10 Mt per year, including 4 Mt for crude and 6 Mt for products. It can accommodate vessels up to 50,000 dwt with a maximum draft of 13 metres. Due to space limitations imposed by the location of the nearby town, expansion possibilities are limited to extending the port outward to deeper water. Phase one of a proposed expansion project would take four years and cost around US$250 million, while construction of an entirely new port would require an estimated US$1 billion. However, the required funds are reportedly not presently available to carry out either project.

Batumi (Georgia) has an estimated annual capacity of 5 Mt. One inside berth can receive crude oil tankers, while two others handle small product carriers. The outside buoy berth at the entrance (12 metres draft) normally can accommodate vessels of 60,000 dwt, but has been out of commission for several years due to problems with a sub-sea connecting pipeline. The potential for port expansion is limited by the proximity to the town. Throughput could be increased somewhat through the addition of an SPM berth outside the harbour basin.

Poti (Georgia) can export small amounts of petroleum products via its general cargo terminal, though is not capable of handling crude oil due to safety considerations. It also has very limited storage facilities. Vessel draft is officially limited to 11.5 metres, but due to continuous silting the actual draft may be closer to 9 - 10 metres. (A maintenance dredger reportedly was being employed in August 1997.) The port has space available for expansion, and Turkish LPG distributor Aygaz plans to open a 5-kt/year terminal at Poti to accommodate possible future Azeri LPG shipments to Turkey.

Supsa (Georgia), near Poti, is the future sight of the oil terminal for AIOC's western pipeline from Baku. As of early 1998 Georgian firm Gruztonnelstroi had finished the first stage of a US$60 million SPM system. The terminal's initial capacity will be 10 Mt/year, with plans to increase this to 50-70 Mt/year. Four storage facilities will be able to handle 240 kt of oil. Both the terminal and the western export line are to be ready in 1999. Itochu (Japan) is contemplating building an oil refinery and a petrochemicals complex near Supsa.

Selected import capacity in the Black Sea

Selected ports that could import oil for transportation to other markets include the following:

Yuzhnoye (Ukraine), near Odessa, is the sight of a planned SPM berth which is to have an annual import capacity of around 12 Mt, with the possibility of expansion to 28 Mt. Construction of the US$250 million first stage began in 1994, but has been held back several times by funding shortages and environmental considerations. Phase two reportedly could be completed in five years at a cost of around US$500 million. The terminal is to be connected to the Druzhba pipeline with a 650-km link from the Black Sea to the western Ukrainian town of Brody. The port could be used to import oil to Ukraine or as a transit point for deliveries to markets on the southern Druzhba pipeline.

Illichevsk (Ukraine) is a small port through which Ukraine plans to import up to 3 Mt of Azeri crude in 1998. The oil will first reach the Black Sea via the Georgian port of Poti to the Ukrainian port of Illichevsk.

In November 1997 Romania signed a protocol with Georgia to land some exported oil at **Constantza**, which is connected to the Black Sea by the Danube River. The governments foresee eventual shipments of 35 Mt per year. The projected transit fee is US$0.30 per tonne.

Bulgaria is discussing the possibility of landing some Caspian crude at its **Burgas** terminal where it could either be refined or shipped onward to Europe.

Table 7 Information on selected key ports for the transit of Central Asian and Transcaucasian oil

Port/Terminal	Berths (No.)	Max. draft (m)	Max. vessel size (k dwt)	Load rate (t/hr)	Capacity (Mt/yr)	Planned expansions
Caspian Sea						
Dyubendi	6	7	7	225	2.6	projected volumes indicate need for 10-11 Mt/yr capacity by 2000
Aqtau (Kazakstan)	3	7-8	5-7	570	5	projected volumes indicate need for 16 Mt/yr capacity by 2000
Turkmenbashi (Turkmenistan)	4	7-8	5-7	130	1.1	none
Neka (Iran)	1	4	4	165	1.5	none; port dredged in 1997
Bandar Anzali (Iran)	1	5	5	200	1.7	none
Black Sea						
Novorossiysk (Russia)	7 1	10-13 24	30-90 250	4,000	35	new berth for 80,000 dwt with 15 Mt/yr throughput
Tuapse (Russia)	6	9-13	50	570	5	new $1 billion port extending to deeper waters planned
Odessa (Ukraine)	5	12	80	1,140	10	new 12-Mt/yr terminal planned nearby in Yuzhnoye
Poti (Georgia)	3	9-10	70	165	1.5	plans to build a 10-15 Mt/yr terminal at Supsa
Batumi (Georgia)	3 1	11-12	60 45	570	5	
Samsun (Turkey)	10	11-12	60	0	0	new container & ro-ro facility rail ferry to Constantza
Burgas (Bulgaria)	3	12	100	685	6.0	
Constantza (Romania)	1	14	150	1,140	10	expand to handle more grain, foodstuff & possibly oil
Mediterranean Sea						
Ceyhan (Turkey)	2 2	18 22	150 300	9,100	80	current utilisation of 17 Mt/yr
Iskenderun (Turkey)	3	12-19	300	0	0	
Alexandroupolis (Greece)	2	7	2	0	0	
Vlore (Albania)	1	6	25	430	3.8	improve old facilities & build a new port
Persian Gulf						
Kharg Island (Iran)	10	31	250	10,000	88	capacity could be increased to original 250 Mt/yr if all berths used

Sources: IEA , Black Sea Economic Co-operation, Ekomorsphera Ltd, Intertanko, Lloyd's, various port authorities.

LEGAL STATUS OF THE CASPIAN SEA

BACKGROUND

A large portion of the oil and gas reserves in Central Asia and Transcaucasia are thought to lie under the Caspian Sea.[1] The question of the ownership of those resources, including the right to license and tax their development, is being debated by the Caspian littoral states. Nevertheless, oil and gas development projects involving a large number of foreign companies have already begun in some sections of the sea.

The legal status of the Caspian Sea effectively came onto the international agenda in April 1994 when the Russian Ministry of Foreign Affairs sent a diplomatic note to the British Embassy in Moscow warning that the issue of ownership of Caspian resources "remained to be settled". The MFA raised the issue in the context of an investment agreement that had just been signed with the Azeri government by a British Petroleum-led consortium (the future AIOC). The MFA's position was further elaborated in a note to the United Nations (see box).

Russia's statements caused concern in the capitals of other Caspian littoral states, as well as the board rooms of companies negotiating offshore contracts in the Caspian. The implication of Russia's claim was that it or any other littoral state might be able to block or critically delay projects, either by veto or by requiring a cumbersome approval process involving all littoral states. They realised that such a situation could make Caspian projects less attractive to investors, and in turn hamper the economic development of Azerbaijan, Kazakstan and Turkmenistan, which hoped to attract significant foreign investment to their offshore regions.

The legal uncertainties do not appear to have significantly slowed investment in the Caspian Sea. Favourable geological prospects provide significant incentives for companies to be present in this important producing region, preferably from the start of its development. Morever, since companies had few indications as to how long a final settlement of these issues would take, they apparently preferred not to delay their plans indefinitely. They appear to be confident that, because agreements have been signed with a large number of companies coming from a variety of states, these agreements will be honoured.

Since 1997 the Caspian legal debate about seabed mineral rights appears to have shifted from a discussion of joint-ownership vs national zones, to where to draw the boundaries between such zones, while agreeing that waters and fishing resources should be jointly managed to promote the freedom of navigation and protect the environment.

1. The Caspian Sea is approximately 1,204 km long with a surface area of 436,000 km^2. In the northern third the average depth is 6.2 m, in the centre 176 m, and in the south 325 m.

Origins of the dispute

In a note to the United Nations of 5 October 1994 the Russian Ministry of Foreign Affairs stated that the Caspian should not be subject to the provisions of international maritime law. (The significance of the application of international law is that a "sea" under the 1982 Law of the Sea Convention would be subject to division into national zones for the development of its mineral resources.) Russia stressed that, until all five of the Caspian littoral states (Azerbaijan, Russia, Kazakstan, Turkmenistan, and Iran) came to a unanimous decision on some other arrangement, the legal status of the Caspian Sea was subject only to the provisions of the more general

- Treaty of Friendship between Iran and the USSR of 26 February 1921, and
- Treaty between Iran and the USSR on Trade and Maritime Navigation of 26 March 1940.

According to the 1994 position of the Russian foreign ministry, the treaties of 1921 and 1940 gave the USSR and Iran national zones only within 12 nautical miles from shore. The area outside these sectors, it claimed, was the common property of the littoral states. It furthermore argued that dividing the Caspian Sea completely into national zones threatened joint co-operation on such important issues as preserving the Caspian's unique eco-system and maintaining freedom of navigation.

The Azeri government countered Russia's position by arguing that

- the two bi-lateral treaties between Iran and the USSR did not pertain to minerals development and therefore should have no bearing on such a discussion;
- Azerbaijan considered the Caspian a sea and therefore subject to division into national zones; even if the Caspian were not declared a sea, there was little precedent in international law for subjecting land-locked bodies of water to joint sovereignty;
- during the Soviet period, the USSR had treated the Caspian as if it were divided into two sectors and did not consult Iran on development outside its 12-mile zone; moreover, Soviet-era maps drew a strait line across the sea delineating an Iranian- Soviet border;
- as further precedent for division, maps drawn up by the USSR Ministry of the Oil Industry divided the Caspian Sea into zones among the local oil industry branches of the respective littoral Republics.

THE RESPONSE OF THE OTHER LITTORAL STATES

At the time of Russia's note to the UN, almost all offshore contracts were being negotiated with Azerbaijan, 95% of whose oil reserves were estimated to lie in what it considered its offshore sector. The legal uncertainty raised by Russia's claims thus directly threatened the economic interests of Baku. Not surprisingly, Azerbaijan has since argued insistently for division of the Sea into national zones (see box).

Kazakstan also called for national zones, though it pointed out that the issue was unsettled, and that a collective approach was needed to solve the ecological and maritime traffic issues. Although Turkmenistan did not specifically endorse Moscow's approach, and has appeared somewhat inconsistent on the issue, it agreed that the issue needed to be solved and that, until there was unanimous agreement, the only relevant legal framework was the treaties of 1921 and 1940.

Some observers point out that Kazakstan and Turkmenistan, which are economically, politically and militarily more dependent than Azerbaijan upon Russia, traditionally have been more circumspect than Azerbaijan about publicly siding against Russia on international issues. Turkmenistan has been completely dependent upon Russia for the transit of gas. It has also traditionally been sensitive to the views of Iran, through which it also hopes to transport gas, and which Iran has been insistent on calling for joint ownership of Caspian resources.

INTERESTS

If the Caspian were divided into national zones, the largest hydrocarbon deposits probably would be in the Azeri and Kazak sectors, and to a lesser extent in the Turkmen sector. In terms of economic development, Russia and Iran both have significant oil and gas deposits elsewhere. The pace of development of hydrocarbon resources of the Caspian Sea, however, is highly significant for the economic development of Azerbaijan, Kazakstan and Turkmenistan.

In practice, Azerbaijan and Kazakstan have offered companies from other Caspian littoral states participation in the development of projects which they consider to lie in their respective national zones. A pattern of de facto benefits sharing seems to be developing. Should this pattern continue, the remaining questions on the status of the Caspian Sea could lose some of their original significance.

While the Russian Ministry of Foreign Affairs has spoken against division of the Caspian into national zones, Russian companies have participated in offshore projects with the Azeri government and western partners. (For example, Lukoil participates in the AIOC, Karabakh and Yalama projects.) Azerbaijan and other FSU littoral states have included Russian companies in projects, at least in part to give Russia a stake in the projects' success, and thus reduce their political uncertainty. As Western investment has grown, Azerbaijan and Kazakstan have become more assertive in affirming their territorial claims and in demanding more from Russian companies just as they have from western ones.

Some observers have noted that by allocating acreage to companies from a broad base of foreign countries, including Russia and Iran, Azerbaijan has given these companies' governments an interest in Azeri development and therefore strengthened its position on Caspian ownership.

FURTHER DEVELOPMENT OF THE RUSSIAN POSITION

At a November 1996 meeting of foreign ministers from Caspian littoral states, Russian Foreign Minister Evgeny Primakov proposed a new legal regime for the Caspian that would have extended the exclusive national zones from 12 nautical miles to 45 (though with only 10 for fishing rights), with the central part of the sea to be held in common. He also proposed the establishment of an interstate committee to license oil and gas exploration in the joint zone, with the possible exception of acreage already awarded. This position was supported by Iran and Turkmenistan, while Azerbaijan and Kazakstan dissented.

In July 1997 Russia announced a tender for Caspian acreage that included areas outside Russia's 12-mile zone. Russia explained this tender by saying that until the Caspian legal issue was settled, joint ownership did not necessarily imply that a consensus was needed for development outside the 12-mile limit.

In January 1998 the Russian government proposed sectoral division of the seabed coupled with shared use of the surface for transportation and of biological resources. In February 1998 Russia and Kazakstan reached a bilateral agreement in principle on seabed division of their sectors along a median line. Further bilateral agreements between littoral states were expected as of April 1998.

BORDER DISPUTES

Division of the seabed potentially can lead to disputes over specific sections. The most difficult border dispute is arguably between Azerbaijan and Turkmenistan. In 1997 the Turkmen president sent a letter to the Azeri president stating that two fields being developed by the AIOC were in Turkmen waters. Specifically, Turkmenistan claimed title to the entire Azeri field and part of the Chirag. It also claimed the Kyapaz field, which recently had been assigned by the Azeri government to Russian companies Lukoil and Rosneft. (Lukoil and Rosneft later postponed the project.)[2] Turkmenistan has said that it is not interested in disrupting the AIOC project or making companies transfer their contracts to Ashgabat. Rather, it says it is asking Azerbaijan for a portion of the profits accruing from the project to the Azeri government.

In February 1997 Azerbaijan and Turkmenistan set up a joint working group to look into the matter. In November 1997 Turkmenistan also lodged an appeal to the UN for help in mediating the case of Kyapaz. As of the beginning of 1998, the issue of the three fields was still under discussion, although the two governments had agreed in principle to demarcation on the basis of median division, subject to negotiation.[3]

2. A major reason for differing interpretations of the boundary has been the different maps each country used to define its national zone. The maps were produced by the USSR Ministry the Oil Industry, giving "zones of influence" to its various republican branches.
3. There are various ways to determine a median line. Moreover, a median line can change depending on the water level, and the Caspian Sea has risen more than 2.5 metres over the past 15 years.

AZERBAIJAN

Azerbaijan at a glance	
Land area	86,600 km^2
Population	7.8 million
Capital	Baku
President	Heydar Aliyev (next election 1998)
Currency	US$ = 4,000 manat (October 1997)
GDP	US$ 3.2 billion (1996)
Real GDP growth	1.3 % (1996)
Consumer price inflation	7 % (1996)
Primary energy production	14 Mtoe (1996)
Energy consumption	13 Mtoe (1996)

SUMMARY

Oil and gas reserves: Proven oil reserves are estimated at 3 - 11 billion barrels, and proven gas reserves at 300 - 800 Bcm. Over 90% of Azerbaijan's total estimated petroleum reserves are offshore. Extensive exploration is to continue in both deep and shallow parts of the Caspian Sea offshore Azerbaijan.

Oil production: Output peaked in 1940, when Azerbaijan accounted for some 70% of total USSR crude oil production. The discovery of oil in Russia's Volga-Urals region, and later in western Siberia, transferred Soviet investment resources away from Azerbaijan and resulted in decreased Azeri production. In more recent times, oil production fell almost 30% between 1990 and 1996 as a result of continuing depletion of existing fields, poor maintenance due to lack of funds, and limits imposed by outdated technology. Oil production in 1997 was 9.02 Mt, of which 7.5 Mt came from offshore fields. Almost 80% of offshore oil production was accounted for by the Guneshli field, with most of the remainder by Neft Dashlary (both operated by Socar). Many new deposits being developed with foreign firms are located at water depths greater than 200 metres. Given proposed foreign investment projects, oil production could reach 14 Mt by 2000, and around 70 Mt per year by 2010.

Oil exports: Over the past five years, Azerbaijan has exported only 10-20% of its oil production. Oil field and pipeline projects under development and planned could raise annual oil exports to 4 Mt by 2000 and 30 - 55 Mt by 2010. Since existing Azeri oil production is already more than enough to meet domestic demand, most oil produced by foreign investment projects will probably be exported. A major issue is lack of adequate export infrastructure. The major projects to build additional export pipelines are being co-ordinated by the AIOC consortium.

Refining: Azerbaijan has traditionally refined most of its own crude oil production, as well as crude imported from other republics, while exporting products. Total refining capacity in Azerbaijan is 20 Mt/year (400 kb/d), over double the country's oil production in 1997. Throughputs fell in the late 1980s as both Azeri crude production and crude imports declined. Most refinery capacity needs significant rehabilitation. Around 8.8 Mt of oil was processed by Azeri refineries in 1997.

Gas: In the early 1990s, natural gas accounted for over 60% of primary energy supply, making Azerbaijan one of the most gas-intensive economics in the world. About 40% of this was imported. Consumption has declined since then, mainly due to a fall in imports from Turkmenistan related to non-payment problems. Since most gas produced in Azerbaijan is associated, declines in gas production have mirrored falls in oil output. Gas production is only likely to increase significantly after 2000, when some of the large offshore oil projects being developed with international consortia begin to come on-stream. Associated gas produced by private investors belongs to Socar. Socar produced about 5.7 Bcm of natural gas in 1997, over 90% of which came from offshore. Production could reach 7.4 Bcm by 2000, and 15 - 24 Bcm by 2010. The country could conceivably reach gas self-sufficiency between 2000 and 2005.

Foreign investment: Major offshore oil and gas deals with foreign investors have been conducted as production sharing agreements (PSAs), each of which is approved by the parliament as a separate law.

ECONOMIC BACKGROUND

Azerbaijan is one of the oldest oil provinces in the world, and was one of the most important mineral resource bases of the USSR during the early Soviet period. Moreover, it maintained a near monopoly in manufacturing oil and gas equipment within the USSR, and remained an important refining centre for Siberian oil.

After the dissolution of the Soviet Union, Azerbaijan's economic lifelines with the rest of the USSR were severed. Economic and political problems were exacerbated by ethnic unrest among the Armenian population in the Nagorno-Karabakh region, culminating in a three year war.[1] Azerbaijan's economy suffered further when Russia, its largest trading partner, closed all rail and road borders between the two countries in September 1994, citing the conflict in Chechnya. (Road traffic was reopened in May 1995.)

Since 1995, several factors have contributed to a gradual return to political and economic stability. The incumbent president, Haidar Aliyev, has consolidated his position internally; an armistice in Nagorno-Kharabak has been adhered to since 1994; and foreign oil and gas companies have confirmed huge offshore reserves under the section of the Caspian Sea claimed by Azerbaijan.

1. A Russian-brokered cease-fire has been in place since May 1994, and the continuing peace process is being mediated by the Organisation for Security and Co-operation in Europe (OSCE).

Azeri foreign policy focuses increasingly on two goals: attracting foreign investment in the oil sector from a wide array of countries, and ensuring a diversity of oil export routes in order to avoid becoming dependent upon any one transit country.

The first years of stabilisation and transition

Between 1990 and 1995, Azerbaijan's GDP plummeted 58%. Oil production fell by only 25%, due mainly to continuing oil product exports to neighbouring countries and an increasing use of heavy fuel oil in domestic power stations to substitute for imported gas. Other sectors, such as chemical fertilizer and machine tool production, were more heavily hit.

In 1996, GDP grew for the first time in six years. Much of this was due to foreign investment, mainly in the oil services and construction industries. Data for the first half of 1997 suggest a GDP growth of 5.2% for the year, with foreign investment apparently filtering down into other sectors such as machine building and non-ferrous metals.

Due to the tightening of monetary and budgetary policies, the fiscal deficit dropped from 11.4 % of GDP in 1995 to less than 2% in 1996; and inflation fell from over 1,700% in 1994 to 82% in 1995, and to only 7% in 1996. Moreover, external debt in 1996 was less than 10% of GDP. By December 1996 such progress convinced the IMF to award an Enhanced Structural Adjustment Facility of US$ 135 million and an Extended Fund Facility of US$ 84 million.

A weak spot has been the exchange rate of the local currency, the manat. After the manat moved to a unified and deregulated exchange rate, the central bank continued to intervene through the foreign exchange market. The currency stabilised somewhat prematurely at around 4,000 manat per US dollar at a time when inflation was still relatively strong. The de facto revaluation of the currency caused imports to soar and the current account deficit to widen. The current account had already been weakened by heavy imports linked to foreign investments (in 1994 it was -5.3% of GDP, and in 1996 it was -12.8%). As long as investments increase, a further deterioration in the current account can be tolerated. However, in the medium and long term, additional oil exports must be large enough not only to compensate for growing consumption related to imports, but also to finance needed infrastructure investments.

Structural reforms

Price and trade liberalisation

When budget subsidies from Moscow ceased after the demise of the Soviet Union, Azerbaijan, like most FSU states, felt obliged to follow the lead of Russia in deregulating prices. However, soft budgetary policies helped turn price reform into rampant inflation. In order to protect consumers, the government continued to control prices for such essentials as food and energy. Although price controls on food were lifted in 1995, energy prices remain administered at all levels. With the exception of utilities for households, energy prices have been raised gradually toward international levels.

Quantitative foreign trade restrictions have been eliminated and most tariffs reduced. The export registration system has also been simplified. For "strategic" exports, including oil, a tax is levied on 70% of the difference between the higher world market price and the domestic price, although this tax does not appear to be applicable to most projects with foreign investment.

Foreign exchange regulations are fairly liberal. The official exchange rate is determined by daily auctions of non-cash foreign exchange on the Baku Interbank Currency Exchange (BICEX). After June 1996, exporters were no longer required to sell 30% of their export revenue at the auctions. Residents and non-residents may open foreign exchange accounts at commercial banks without declarations on the origin of foreign funds, and non-residents may transfer funds relatively freely abroad.

Privatisation and demonopolisation

In accounting terms, the State is much less involved in the economy than it was in 1992. The share of government consumption in GDP fell from 24.2% in 1992, to 9.7% in 1996. According to the EBRD, however, only 25% of the Azeri economy could be considered private by the end of 1996, with most large and medium scale enterprises still fully state owned. Among the four countries reviewed in this report, only Turkmenistan, with a rate of 20%, was considered less privatised. Small scale enterprises represent the only sector where privatisation is relatively advanced. The approximately 3,600 small enterprises privatised and newly created by the beginning of 1997 included 203 petrol stations (out of a total of 670).

The first round of mass privatisation, done on the basis of vouchers, was carried out by the State Property Commission in early 1997 and excluded energy enterprises. According to the Privatisation Programme for 1995-1998, energy enterprises may only be privatised by presidential decree.

Payment arrears

Inter-industry arrears rose from 27.4% of GDP in 1994 to 104.5% by the end of 1996. In September 1996 a presidential decree allowed the netting out of existing arrears among enterprises and the selling of net positions to the banking system. The payment discipline of budgetary organisations is still a major handicap for the economy.

Arrears for general taxes due have grown, especially among enterprises in the oil and gas industry.

The Banking system

Parliament enacted a central bank law in June 1996 that gives the Azeri National Bank (ANB) independence in monetary policies and relieves it from the obligation to finance the state budget. The ANB's new tasks are to achieve price stability and foster the development of a sound banking system, which in 1997 consisted of four large state-owned banks and some 160 private banks. Interest rates have been lowered by the ANB with a lag to the fall in inflation. The large spread among rates for final lenders has narrowed as stage guarantees for state-owned enterprise were phased out and credit risks became more evenly distributed among different groups of lenders.

Long term outlook

Crude oil exports are expected to be the driving force behind the development of the country's industry and infrastructure. Although the oil an gas sector is not extremely labour intensive, a secondary oil equipment and oil service industry should offer ample opportunities for a well-educated work force. Important infrastructure requirements such as the building of pipelines, telecommunications, power plants and petrochemical industries will provide further opportunities. Obstacles may occur from slow progress in market reforms and poor corporate governance. Moreover, there are external political risks related to ongoing tensions with Armenia over Nagorno-Karabakh.

Among the four countries covered by this study, Azerbaijan is expected to have the highest foreign investment share in GDP (around 30%) by 2010.

OVERVIEW OF THE ENERGY SECTOR

Oil and gas account for a large portion of both energy production and consumption. Energy production in 1996 was around 14.4 Mtoe, of which approximately 36% was gas, 63% oil, and 1% hydro-electricity. Azerbaijan produces almost no coal. Energy consumption has traditionally been dominated by gas, though its share has declined with the fall of gas imports.

Until recently, Azerbaijan imported large amounts of gas, mainly from Turkmenistan. Higher prices and subsequent payment difficulties led the government to cut imports, substitute fuel oil for gas in power generation, and concentrate on developing indigenous gas resources. Unlike new oil projects, which are intended mainly for export, new gas developments have been aimed primarily at the domestic market.

Electricity

Both oil and gas play an important role in electricity generation in Azerbaijan. Total electricity generating capacity is about 5,100 MW, of which 3,600 MW (71.6%) is accounted for by the country's nine thermal plants. Azerbaijan's nine hydro-electric plants account for 820 MW of capacity, and its CHPs for 616 MW.

Thermal plants produce over 90% of Azerbaijan's electricity. Electricity production in 1996 was 24% below the 23.2 billion TWh produced in 1990.[2] Generation might have fallen further had it not been for the ability to substitute domestic fuel oil for imported gas in many of Azerbaijan's thermal power plants. Of the 17.5 billion kWh generated in 1996, 13.2 billion kWh was produced from fuel oil and 2.3 billion kWh from gas. In the past, when natural gas supplies were reliable, thermal generation was roughly evenly divided between fuel oil and natural gas.

2. The relatively small fall in output compared to the drop in overall economic activity is similar to the pattern in other transition economies. In part this is due to the large overhead uses of energy in the industrial sector, implying that energy intensities have risen dramatically. This may also signify problems in accounting for energy used in the black and grey areas of the economy.

Before the breakup of the Soviet Union, Azerbaijan was a major supplier of electricity to the rest of Transcaucasia. It lost markets due to a number of factors, including lower demand in Georgia and the Azeri blockade of Armenia. In recent years Azerbaijan imported small amounts of power.

Some 25% of total generating capacity is considered spare capacity and is likely to remain idle due to decreased demand, lost export markets, lack of fuel and spare parts, and insufficient funds for maintenance. The government programme, *Development of Electric Power in the Republic to the Year 2010*, envisages new construction and reconstruction of existing thermal stations, with an emphasis on gas turbine technologies. This programme reportedly will require some US$1.5 billion in investments through 2010, in addition to US$30 million for the further development of the power grid.

Coal and shale

Azerbaijan uses very little coal and imports virtually all the coal it uses. However, such imports have fallen to less than 0.1 Mt per year, from around 0.2 Mt in 1990.

Azerbaijan has some 150 Mt of oil shale reserves, mostly in the eastern part of the country. It is not clear whether exploitation of these resources is economical. Possible uses of oil shale are burning in thermal power stations, high temperature processing to obtain gas, and semi-coking of shale tar to produce liquid fuel and other chemical products.

ORGANISATION OF THE OIL AND GAS SECTOR

As of the beginning of 1998, there was no co-ordinating body for energy issues; policy was made by the President's office and by the state-owned companies that operate in the various energy sub-sectors.

The State Oil Corporation of the Republic of Azerbaijan (Socar)[3] was created in 1992 by combining the onshore upstream operations of Azneft and the offshore activities of KhezerDenizNeft, successor organisations to the former Soviet Ministry of Oil and Gas operating in Azerbaijan. It produces most and oil and gas in Azerbaijan and negotiates contracts with foreign investors in this area on behalf of the government.

Azerigaz is responsible for the transportation, storage and sales of natural gas (while Socar handles production and processing). It was formed in 1992 with the merger of the national gas transmission company and the natural gas distribution branch of the State Fuel Committee. As part of the conditions related to a World Bank loan for the rehabilitation of the country's gas industry, a Presidential decree of May 1997 corporatised Azerigaz and transferred its shares to the State Property Committee for sale at a later date.

The government announced in 1997 that it intended to set up a ministry to co-ordinate energy policy, though by the beginning of 1998, such a ministry had not been created. The functions

3. In Azeri: Azerbaycan Respublikasi Dövlet Neft Sirketi. It is also sometimes referred to by its Russian acronym, GNKAR.

of the new ministry are to include developing energy policy, preparing legislation, setting tariffs, and ensuring the state's energy security. It is not clear how much of a role such a ministry would have in the oil and gas sector. Although the separation of Socar's policy making and licensing role from its commercial functions has been mooted, the new ministry might concentrate on the domestic provision of electricity and gas. In any case, most important policy decisions affecting the oil and gas industry will probably continue to be made by the President's office.

OIL RESERVES AND PRODUCTION

Oil reserves

According to Socar, Azerbaijan's proven oil reserves total some 17.5 billion barrels, while most outside estimates place recoverable oil reserves at 3 - 11 billion barrels. For example, a 1996 US government report estimates proven oil reserves at 3.6 billion barrels, with some 27 billion barrels additional reserves classified as possible. Over 90% of Azerbaijan's total oil reserves are thought to be offshore.

Extensive exploration is to continue in both deep and shallow parts of the Caspian Sea offshore Azerbaijan, especially near the Apsheron Peninsula. Onshore exploration during the next few years is to concentrate on the central and western parts of the country.

In common with the situation in most OECD countries, the State holds monopoly title to the subsoil, including offshore, and the undeveloped resources within it.

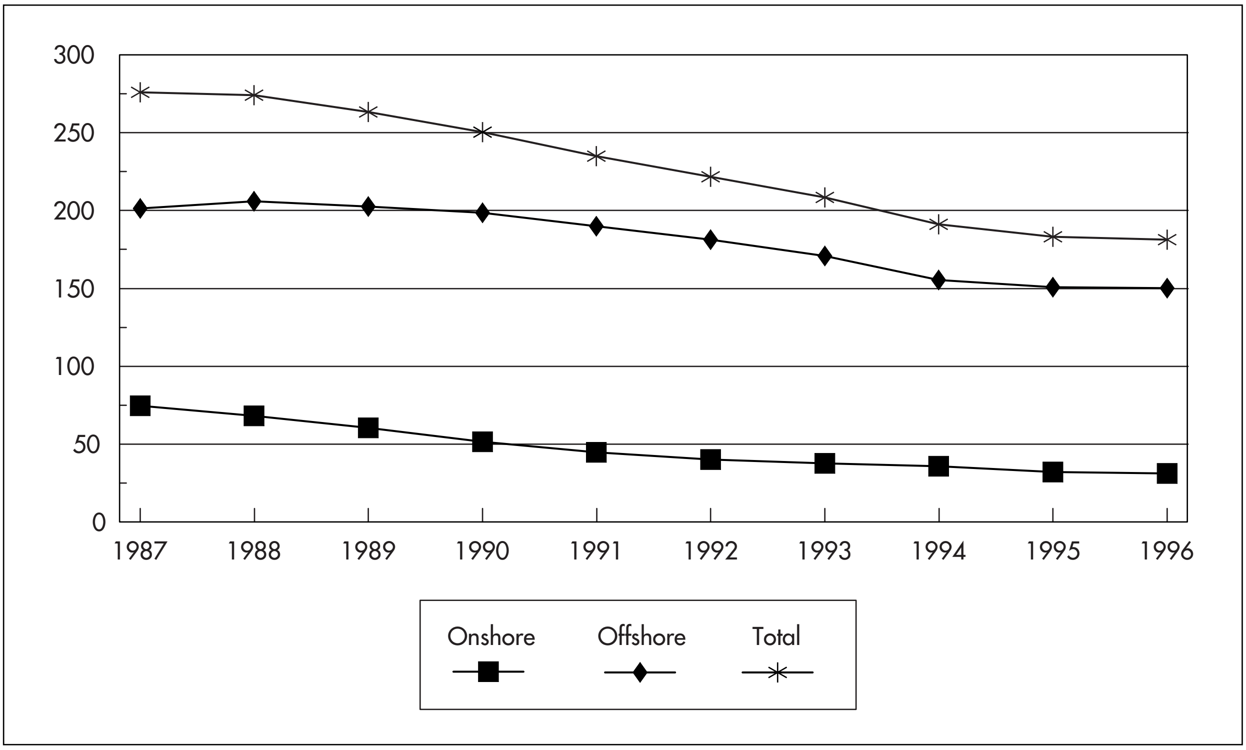
Oil production

Oil production fell from 12.5 Mt in 1990, to 9.02 Mt in 1997, due to continuing depletion of existing fields, poor maintenance because of lack of funds, and limits imposed by outdated technology.

One of the first oil wells in the world was drilled in Azerbaijan's Apsheron peninsula in 1848. By the beginning of the 20th century, Azerbaijan accounted for almost one half of world crude oil production. Output peaked at around 23 Mt in 1940, when Azerbaijan accounted for some 70% of total USSR crude oil production. The discovery of oil in the Volga-Urals region of Russia led to a switch in investment priorities in the Soviet oil industry that transferred resources away from Azerbaijan.[4] By 1950, production in the republic had fallen to 15 Mt. Azeri output climbed again to reach 20 Mt in 1970 as investments increased, though the drive to develop the new oil province of western Siberia led to a further decrease in resources and another decline. Total Azeri output was 12.5 Mt in 1990, at which time Azerbaijan accounted for around 2% of Soviet oil output. Oil production in 1996 was 9.13 Mt (183 kb/d), of which some 87% was produced offshore. Socar produced 9.02 Mt in 1997.

4. Another reason for switching field priorities eastward was the geographic vulnerability of Azeri fields, the capture of which was a German objective during WWII.

Figure 1 Azeri average oil production rates



The State Technical Inspection Agency, Goskomtekhnadzor, estimated "illegal" (unreported) production in 1996 at around 1.3 Mt (26 kb/d) of additional oil. Products refined from undeclared crude are either sold on the internal black market or exported illegally.

Oil fields

Socar operates approximately 40 oil deposits. During the first quarter of 1997, the number of active wells was 6,901, of which 5,512 were onshore and 1,389 offshore. The total number of active wells was up from 6,802 in 1996, with most of the increase coming from the rehabilitation of idle wells.

Most of the oil produced onshore in 1996 came from only 10 fields. Onshore deposits are usually small, old and characterised by low productivity, high water encroachment rates and high gas factors. The typical onshore well produced 10 b/d with a water cut of 92%, while the typical offshore well produced 100 b/d, with a water cut of 46%. Between 1985 and 1995, onshore oil and condensate production fell by 59%, compared to an 18% drop for offshore production.

Exploitation of the Caspian Sea offshore Azerbaijan began in 1949, and annual production reached over 10 Mt by the late 1980s. Mirroring sliding oil output elsewhere in the former Soviet Union, Azeri offshore production fell to 8.09 Mt by 1994 and to 7.50 Mt by 1997. Offshore output in 1998 is expected to increase slightly, due to production by the AIOC consortium.

In 1997, Azerbaijan had over 17 offshore fields in production, most located in water depths of under 200 metres. Almost 80% of offshore oil production in 1996 was accounted for by the Guneshli field, with most of the remainder by Neft Dashlary. (Both are operated by Socar.)

Oil prices

Although most prices in Azerbaijan have been liberalised, those for utilities and petroleum continue to be administered. Domestic crude oil prices gradually have been raised toward world market prices minus transport costs. Domestic oil product prices before VAT, road tax and excise taxes, are comparable with international oil product prices. In February 1998 the internal price for one tonne of crude oil was 273,000 manats (US$70).

The oil sector's share in taxation

In an effort to diversify economic development, governments of oil exporting countries usually tax the oil sector more than what would normally be justified by its share in GDP. For example, the oil industry's contribution to total tax revenue in Kuwait is 3 times its contribution to GDP, and in Venezuela the oil industry's contribution to the budget is twice its GDP contribution. Oil exporters of the former Soviet Union have much lower ratio's. For example, Azerbaijan's is 1.2, Russia's is 1.1 and Turkmenistan's is 0.3. A major reason for the lower rate in FSU countries is the relatively larger level of tax arrears in the oil and gas sector, compared with the rest of the economy. In 1994, while over 90% of taxes due were collected in the rest of the economy, the rate for the oil industry was only 43%. Had it been 100%, Azerbaijan's oil industry would have paid 2.3 times its share in GDP, a figure more in line with oil exporters in other parts of the world.

OIL REFINING

Total refining capacity in Azerbaijan is 20 Mt per year (400 kb/d), which is approximately double the country's oil production in 1997. Of the three refineries, the main ones are in the Baku area, and the third in Sumgait. All are run by state-owned refiner, Azneftemash.

In 1997, Azerbaijan refined 8.8 Mt (kb/d), or almost all of the country's production. This compares to a figure of 9.70 Mt (194 kb/d) in 1992.

In the mid-1970s to mid-1980s, as domestic crude oil production fell, significant amounts of oil were imported from Russia and Kazakstan to utilise idle refinery capacity. By the mid-1980s, imported crude represented some 40% of the country's refinery throughput, and Azeri oil products were shipped to other Soviet republics via rail and across the Caspian by ship.

In 1981, Azerbaijan processed 13.3 Mt of domestic crude, while crude imports were 5.1 Mt from Russia and 2.2 Mt from Kazakstan. In 1985, imports of crude from Kazakstan surpassed those from Russia, at 5.6 Mt and 3.2 Mt, respectively, at which time Azerbaijan produced 12.4 Mt. By

Table 1 Azeri oil refining 1992-1995 (Mt/year)

	1992	1993	1994	1995
Refinery Input	9.70	9.49	8.97	8.44
Input minus 7% for losses	9.02	8.83	8.34	7.85
Actual refinery output	9.24	8.98	8.38	7.59
NGL	0.30	0.32	0.26	0.22
Refinery gas	0.20	0.27	0.22	0.15
Petrol	0.90	0.88	0.83	0.84
Jet kerosene	0.60	0.59	0.56	0.53
Other kerosene	0.20	0.10	0.10	0.10
Diesel	2.35	2.29	2.17	2.01
Heavy fuel oil	4.15	4.06	3.84	3.35
White spirit	0.02	0.02	0.02	0.02
Lubricants	0.20	0.16	0.13	0.13
Bitumen	0.08	0.08	0.07	0.06
Petroleum coke	0.04	0.05	0.03	0.03
Other	0.20	0.15	0.15	0.15

1991, imports of Russian and Kazak crude had fallen to 2.5 Mt and 2.2 Mt, respectively, and Azeri production to 11.1 Mt. Total refinery inputs fell 28% between 1990 and 1995, from 11.75 Mt to 8.44 Mt, reflecting a further drop in crude imports during this period. Output of most products fell accordingly.

Crude imported from Russia has been mainly from Tyumen, while that from Kazakstan has been mostly lower quality Buzachi crude, which has a high sulphur and metals content. Although both of Azerbaijan's main refineries were designed to run on higher quality domestic crudes, most imports have had to be refined at the more sophisticated Azerneftyyanadjag refinery, leaving most domestic crude for the older Azerneftyag plant.

Most of Azerbaijan's refining capacity requires significant rehabilitation. Refinery losses in 1994 of 0.7 Mt/y (14 kb/d) were equivalent to 7% of production. (A typical figure for refinery losses on crude intake in IEA countries is 0.5%.)[5] The lack of significant secondary refining capability results in a large proportion of heavy fuel oil output of 43 - 46%.

Most fuel oil is sold to state-owned utility Azerenerji to produce electricity. Almost all dual-fired Azeri power plants which can switch from gas to fuel oil have done so, due to the decision to decrease gas imports. Lower refinery throughputs have actually meant a shortage of fuel oil, leading to swaps of Azeri diesel for fuel oil from Turkmenistan. (About one tonne of Azeri diesel reportedly has been swapped for two tonnes of Turkmen fuel oil.)

A programme to increase output from Azerbaijan's two main refineries to 500 kb/d by 2005 was drafted by the government in 1995. It is estimated that around US$300 million of investments would be needed to raise product quality at these plants to world standards.

5. However, it is unclear whether the figure for Azerbaijan includes refinery fuel; if it did, Azeri losses would be within western ranges.

Refineries

Azerneftyag refinery

Much of Baku's Azerneftyag (formerly Bakinsky or Baku) refinery was constructed in the early 1930s, though the site dates from the 19th century. Azerneftyag has a current throughput capacity of around of 235 kb/d. It contains several crude and vacuum distillation units, though lacks reforming units to produce marketable petrol. Currently it is used mainly to produce lubricating oil and bitumen, with byproducts of diesel oil, fuel oils and straight run kerosene.[6] It also sells naphtha to the Sumgait petrochemicals plant as feedstocks.

In 1997, Laki Engineering (S. Korea) and Petrofac (US) began an expansion and modernisation project which will include construction of two atmospheric and associated vacuum distillation units.

Azerneftyyanadjag refinery

Baku's Azerneftyyanadjag (formerly Novo-Bakinsky) refinery was constructed in 1953 and substantially rebuilt in 1965. It contains a fluidised catylitic cracker, a coker and several light-end polymerisation units. A reformer was installed in 1980, and a combination catalytic cracking unit was brought on-line in 1993 to improve the quality of high octane petrol. Crude and vacuum distillation capacity was increased from 120 kb/d to 160 kb/d in 1976, though current throughput capacity is around 150 kb/d.

Environmental concerns at the refineries

Environmental standards appear to be fairly low at Azerbaijan's two main refineries. Both prefer to pay the relatively low penalties for non-compliance rather than invest in pollution monitoring and control. The refining industry is one of the main sources of air pollution in the Baku area. At the Azerneftyag refinery, part of the cooling water is discharged back into the sea without treatment, and there is significant seepage of oil into the ground. According to the World Bank, around US$1.5 - 2 million would be required for modernising the ariel pollution control systems at the two plants.

Distribution of oil products

Azerbaijan currently has over 670 petrol stations in operation, over one-third of which have been privatised. All stations were previously run by the State Fuels Committee (Goskomtoplivo), which was abolished in 1994. Lukoil has built three filling stations in Baku and plans to construct three others in the near future, including two outside the capital.

Product movements within Azerbaijan are by rail and road. There are no significant product pipelines.

6. Through the late 1980s it produced more lubes than was required for domestic consumption and was a major supplier of specialty lubes for other regions of the Soviet Union.

Consumption of oil products

Table 2 Azeri oil product consumption 1992-1995 (Mt)

	1992	1993	1994	1995
Total	6.49	7.31	6.56	5.50
NGL	0.30	0.32	0.26	0.22
Refinery gas	0.20	0.27	0.22	0.15
Petrol	0.90	0.88	0.83	0.75
Jet kerosene	0.46	0.53	0.43	0.34
Other kerosene	0.20	0.10	0.10	0.10
Diesel	1.30	1.29	0.66	0.38
Heavy fuel oil	3.49	4.02	3.78	3.55
of which for power stations	3.35	3.39	2.96	3.41
White spirit	0.02	0.02	0.02	0.02
Lubricants	0.20	0.11	0.03	0.01
Bitumen	0.08	0.08	0.07	0.04

Domestic consumption of oil products in 1995 was about 5.50 Mt (110 kb/d), down from 6.49 Mt in 1992. Domestic consumption in 1995 represented 72.5% of total crude oil production for that year.

In 1995, approximately 20% of Azeri oil product consumption was accounted for by road transport fuels, and almost 65% by heavy fuel oil, the latter mostly for the power sector. Consumption of fuel oil rose significantly in 1991 due to its use in the power sector to substitute for diminished imports of natural gas from Turkmenistan.

OIL TRANSPORTATION AND TRADE

Crude exports

Azerbaijan has traditionally refined most of its own crude oil production and some crude imported from its neighbours, while exporting products. Over the past five years, Azerbaijan has exported only 10 - 20% of its crude oil production, in the form of both crude and oil products. (This compares to a figure of well over 30% for Russia.) In 1997, Azerbaijan exported around 290 kt of crude, all via rail through Georgia, while importing some 260 kt from Turkmenistan and Kazakstan. Net oil product exports in 1997 were around 1870 kt.Azerbaijan plans to export a much higher percentage of future output than it does currently, though faces a number of problems, including lack of export pipelines. Oil field and pipeline projects under development and planned could raise oil exports to 4 Mt by 2000, and to around 30 - 55 Mt by 2010.

AIOC pipelines

The major oil export pipeline projects from Azerbaijan are connected with the Azerbaijan International Operating Company (AIOC) consortium's development of the Azeri, Chirag and deep-water Guneshli fields. As part of its contract with the Azeri government, the AIOC is responsible for helping the government to develop export routes. The construction of pipelines has been divided into an "early oil" phase, for production up to about 300 kb/d, and a "main oil" phase, to handle throughput of 700 - 800 kb/d of AIOC and other oil. According to the AIOC, the main oil pipeline will probably be needed by 2003, though some contend it could be delayed a few years by expanding the capacity of the early oil routes.

In October 1995 it was decided to split AIOC's early oil between two export routes: the "northern" route to Russia's Black Sea port of Novorossiysk, and the "western" route to Georgia's Black Sea port of Supsa. Both routes are to have an initial capacity of about 5 Mt per year (100 kb/d) apiece.

The northern route

The northern route, which opened in December 1997, consists mainly of upgraded (and in some cases rebuilt) sections of pipeline from Baku to Novorossiysk via Grozny (in Chechnya) and Tikhoretsk. The section within Azerbaijan was originally used to import Russian oil for processing in Azeri refineries and had to be reversed. The upgrading and replacement of the 1,411-km section within Russia was the responsibility of Russia's Transneft, which also financed the work. In return, Transneft is to receive a transit fee of US$15.67 per tonne.

Transneft takes title of the oil at the Azeri-Russian border and is responsible for delivering an equivalent amount of oil at Novorossiysk. This arrangement, which allows Transneft to substitute Russian for Azeri oil if necessary, in effect represents a trade of quality control for security of supply.

Some 153 km of the northern route pass through the secessionist region of Chechnya in the Russian Caucasus. Continued unrest in this region poses some concern for oil shippers in Azerbaijan. Much of this section was damaged during the Chechen war. An important issue has been the division of repair responsibilities between Transneft and the local Chechen oil company, Yunko[7], as well as the Chechen share of Transneft's transit revenues. A compromise was reached in September 1997 between Transneft and the Chechen company to cover deliveries and repairs in 1997, though a longer term solution was still being negotiated as of the beginning of 1998. In the meantime, the Russian government has ordered preparations for a 283-km bypass between Khasavyurt (in Dagestan) and Tikhoretsk, at an estimated cost of US$200-220 million, to be financed by Transneft. The Russian Ministry of Fuel and Energy has stated that the by-pass would be used principally as a back-up in case of problems on the route via Chechnya. The Chechen government has called the plan a bluff to increase Transneft's bargaining position in tariff sharing negotiations. The bypass appears to be influenced by Russia's determination to make the northern route an attractive option for the main oil pipeline. Upgrading the current northern route to serve as the main oil route would cost an estimated US$2 - 2.4 billion.

7. In October 1997 the Chechen government split Yunko into four separate companies, each of which reports directly to the Chechen Cabinet. Caspian Trunk Pipelines is the Chechen company that now oversees the pipeline shipping Azeri oil through Chechnya.

The western route

The 920-km western route from Baku to the Georgian Black Sea port of Supsa is scheduled for completion by early 1999. Similar to the northern route, it combines both existing stretches of pipeline with new sections. AIOC, which is financing the western route, has allocated US$315 million for the project, of which US$60 million will be used to build a terminal and storage facilities for 240 kt of oil in Supsa. The Supsa terminal will have an annual capacity of 10 Mt, with the possibility to upgrade eventually to 50 - 70 Mt. A tanker loading platform is to be built 2.5 km offshore. Five pumping stations are also to be constructed along the route.

In exchange for AIOC financing, Georgia is to be paid a relatively low transit fee of US$0.17 per barrel (about US$1.24 per tonne). The pipeline will be operated by the Georgian Pipeline Company, an AIOC affiliate. After 30 years the pipeline is to revert to Georgia. Some assistance in financing the western route may come from the EBRD and IFC.

New pipeline on the western route will include the 150-km section from Akstafa on the Georgian-Azeri border to the Georgian village of Samgori. After initial upgrading work on other sections, which included repairing several thousand illegal taps, the original timetable and cost estimates for repair appeared optimistic. In particular, it became evident in early 1998 that much existing pipeline in Azerbaijan would probably have to be replaced rather than refurbished.

After the initial planned capacity of 120 kb/d is built, the western route could be upgraded to handle 200 kb/d at an estimated additional cost of US$300 million. Upgrading the route to serve as the main oil pipeline would take an estimated additional US$1.2 - 1.5 billion. Since much of the early oil pipeline may now have to be built from scratch, there has been some talk of increasing the pipeline's initial capacity.

A number of refinery building and upgrade projects are being considered in Georgia to take advantage of the region's possible role as an oil transportation hub. These include a US$250 million modernisation of the Batumi refinery by Marubeni (Japan) to increase annual throughput capacity there from 2 Mt to 6 Mt.

Ceyhan route

In July 1997 the AIOC announced that it had narrowed the routes for the main oil pipeline to three routes: the two used for early oil, plus a third route to the Turkish Mediterranean port of Ceyhan.

Estimated costs for a main oil pipeline to Ceyhan are between US$2.5 - 3.4 billion, depending on the route[8] and the use of existing facilities, including pipelines and the terminal at Ceyhan. One of the main advantages of a pipeline to Ceyhan is that it would bypass the environmentally sensitive Turkish Straits (see Background and Issues chapter). This route has received strong

8. The Turkish government reportedly would like the pipeline to run through Tbilisi and the Turkish cities of Erzurum, Erzincam and Kayseri. Such a route would be about 1,700 km.

endorsement from the governments of Turkey, Azerbaijan and the United States. However, its cost competitiveness against other routes may depend on the offering of significant fiscal and other incentives by the Turkish government.

Main oil

An Azeri government-AIOC commission headed by Deputy Prime Minister Abed Sharifov is to make a final decision on the main oil route in October 1998. Financing, ownership, and access issues are also to be discussed at this time. It is expected that Socar will own a large percentage of the pipeline, with the rest divided between various shippers, perhaps including companies outside the AIOC consortium. The terms for shipping oil owned by pipeline non-shareholders also remains to be determined. The pipeline commission will be empowered to negotiate with the governments of potential transit countries. Since Socar is expected to be one of the largest users of the main export pipeline, and since AIOC members are able to recover transport costs before paying revenue to the Azeri government, it will be in Baku's interest to keep transport costs as low as possible.

Exports of oil products

Prior to the breakup of the Soviet Union, and a corresponding deterioration in trade and payment relationships between its constituent Republics, Azerbaijan was a significant exporter of refined products, especially to Georgia, Armenia and Ukraine. Total product exports in 1990 were 3.65 Mt, of which about 1 Mt was diesel and 1.4 Mt heavy fuel oil.

In 1994, when oil product exports accounted for about 75% of hard currency earnings, Azerbaijan exported 1.82 Mt of petroleum products, of which about 1 Mt went to Iran. Petroleum product exports reached 2.09 Mt in 1995 and 2.60 Mt in 1996, over half of which were diesel. In 1996 approximately 0.72 Mt of oil products were exported from Azerbaijan via the Georgian Black Sea ports of Batumi and Poti. The rest went via rail, road or across the Caspian Sea by tanker. For example, Russia's Lukoil shipped some 0.5 Mt of products by tanker from Baku to the Russian Caspian port of Makhachkala. In 1997, Azerbaijan exported some 2.9 Mt of oil products, which reportedly earned US$2.62 million.

New trading relationships are developing, with oil product sales to Georgia, Kazakstan, Russia, Turkmenistan and Iran. In 1997, with the increased domestic demand for heavy fuel oil as a substitute for gas in power generation, most product exports were diesel.

Table 3 Azeri crude and product exports in 1997 (Thousand tonnes)

Destination	Crude	Petrol	Diesel
Iran		129.8	1,021
Georgia	292.7	104.1	344.0
Russia		74.0	263.6

Source: Interfax

Table 4 Azeri crude and product imports in 1997 (Thousand tonnes)

Source	Crude	Diesel
Turkmenistan	114.6	68.1
Kazakstan	146.3	

Source: Interfax

Given the poor shape of Azerbaijan's refineries, it is questionable whether continued refining for domestic use, let alone exports, will prove more economical than importing products.

Oil storage

Some 120,000 tonnes of oil storage capacity is located at the Dyubendi oil terminal near Baku, where state-owned Trunk Oil Pipelines manages six tanks, each with a capacity of 20,000 tonnes. Two of these tanks were completed in July 1997.

GAS RESERVES AND PRODUCTION

In the early 1990s, natural gas accounted for around 60% of Azerbaijan's primary energy supply. This figure decreased in the mid 1990's, mainly because of a fall in the amount of gas imported from Azerbaijan's suppliers due to non-payment problems. Nevertheless, gas continues to play a dominant role in the Azeri economy.

According to Socar, Azerbaijan's proven gas reserves are about 800 Bcm, while most outside sources place them between 300 - 800 Bcm. A 1997 US Government report estimates recoverable gas reserves at around 300 Bcm, with another 1,000 Bcm classified as possible.[9]

The three offshore fields being developed by the AIOC consortium alone are estimated to contain 70.8 Bcm of natural gas, while the Nakhichevan and Kyapaz fields may contain an additional 280 Bcm. Onshore reserves appear nearly exhausted.

The main upstream gas producer is Socar. Most of Azerbaijan's gas production is associated with offshore oil production. The gathering infrastructure for offshore natural gas is relatively well developed for the main producing fields and is expected to be expanded as new offshore oil fields are brought on-stream by the AIOC and other consortiums. According to most contracts signed with international investors, associated gas belongs to Socar, though the responsibility to develop and gather it appears to vary by project.

Gas production in Azerbaijan reached a high of 14 Bcm in the mid-1980s, though declined to 6.4 Bcm by 1994, at which time only 0.2 Bcm came from onshore fields. Production increased

9. Report to Congress on Caspian Region Energy Development, 1997.

slightly to 6.6 Bcm in 1995, due to the one-off effect of a project to capture gas previously vented at the Guneshli and Neft Dashlari offshore fields. (Over 1 Bcm per year was flared at Guneshli prior to the gas capture project). The declining trend continued again in 1996 when total production decreased to 6.3 Bcm in 1996 and 5.7 Bcm in 1997.

Increased offshore gas recovery

In 1994, Pennzoil (US) and Ramco (UK) completed a US$150 million project to recover gas from the Guneshli and Neft Dashlary offshore oil and gas fields. The project involved laying an underwater pipeline from the Guneshli field to the Neft Dashlary shallow water offshore complex, constructing a compressor plant at Neft Dashlary, and completing a partially built pipeline from Neft Dashlary to the onshore processing plant at Karadag. The scheme allows the capture of up to 1.4 Bcm per year and reportedly saved the country some US$90 million on gas imports during its first year of operation. A 900-mm gas pipeline is to be built from the AIOC's Chirag field to the compressor at Neft Dashlary.

In 1997 Itochu (Japan) was awarded a contract to build a US$1 million gas compressor station at the Bakhar field, which could increase Azeri gas production by some 2 Bcm per year.

Azerbaijan's largest single domestic source of gas in 1998 was the offshore Bakhar field, which produces large amounts of gas condensate. In 1991 Bakhar accounted for 51% of Azerbaijan's gas production. However, since the mid-1980s, production at Bakhar and most other large fields has declined. Only production from Guneshli has remained relatively constant. Five new wells being drilled at the Bakhar, Bulla-Deniz and Apsheron fields could reportedly increase gas production by 2 Bcm per year and should be on-line in 1998. (Development costs for the five wells are estimated at US$8 million.) Refurbishment of the Bakhar fields and the shallow portion of the Guneshli reportedly could supply another 6 Bcm per year, doubling current production.

Table 5 Azeri natural gas production, trade and consumption (Bcm)

	1990	1991	1992	1993	1994	1995	1996
Produced*	9.925	8.681	7.873	6.805	6.378	6.643	6.305
Delivered*	8.779	7.694	6.969	5.998	5.353	5.677	5.301
Imported (gross)	13.113	14.165	5.264	2.972	2.502	0.594	0.24
Exported/transited	5.424	5.995	0.951	0.448	0.0	0.0	0.0
Consumed	12.190	10.956	11.235	8.881	8.880	7.237	6.239

* The definition of production apparently includes gas flared and vented, while delivery includes only gas delivered to the transmission/distribution system, whether processed or not.

Source: Azerigaz.

Since most gas produced in Azerbaijan is associated, declines in gas production have mirrored falls in oil output. Gas production is only likely to increase significantly when some of the large offshore oil and gas projects being developed with international consortia begin to come on stream. Azerigaz forecasts production to reach 18 Bcm in 2010, while the IEA scenarios call for 15 - 24 Bcm.

GAS PROCESSING, TRANSMISSION AND DISTRIBUTION

Gas processing

Socar is responsible for gas processing. Azerbaijan's main gas processing facility is the Karadag plant, most of which was built in 1961. Its six gas processing trains and one condensate train have a design capacity for processing 6.5 Bcm per year of gas and 675 kt of condensate. Actual capacity in 1997 was about 4.5 Bcm. Karadag receives gas from two main pipelines. The Guneshli line brings gas from offshore fields east of Baku, while the Narimov-Bulla Deniz line transports gas from onshore and offshore fields south of Baku.

Gas studies

Statoil (Norway) has produced a study, "Gas Infrastructure of Azerbaijan", which it presented to Socar in January 1998.

In February 1998, Exxon (US) began a one-year study to assess the Azeri gas market and the potential for gas exports.

Around the same time, Conoco (US) began a joint study with Socar to evaluate Azeri onshore and offshore gas reserves, as well as the commercial viability of upgrades to gathering, processing and transportation infrastructure to bring liquid and natural gas to domestic and export markets. Conoco is reportedly also studying the feasibility of exporting Azeri LPG to Turkey.

In March 1998, Shell announced that it would carry out a joint study with Socar on prospects for developing the country's gas sector.

Although Karadag is in poor condition, a more serious problem is probably the lack of field compression and pipelines to transport offshore gas to the processing facility. Many gathering pipelines lead directly into the transmission system, exacerbating corrosion problems for the network and end-use equipment. In addition to increasing the amount of gas available for distribution, the 1994 project to recover gas from the Guneshli and Neft Dashlary offshore fields (see box) increased the amount of gas sent for processing from 2.9 Bcm in 1993 to some 4.3 Bcm in 1995. Azerbaijan reportedly processed 5 Bcm per year in both 1996 and 1997, although some sources suggest considerably lower amounts. The World Bank has financed a feasibility study to replace the Karadag plant.

Gas transmission and distribution

State-owned Azerigaz is responsible for transportation, transit, storage and distribution of natural gas. The company was formed in 1992 with the merger of the national gas transmission company and the natural gas distribution branch of the State Fuel Committee. Azerigaz's charter forbids it to engage in gas-extraction, which remains the prerogative of Socar. As part of conditions relating to a World Bank loan for the rehabilitation of the country's gas industry (see below), a Presidential decree of May 1997 corporatised Azerigaz and transferred its shares to the State Property Committee to be sold at a later date.

The high pressure gas transmission system maintained by Azerigaz has a total length of about 4,500 km, with pipes up to 1,200 mm in diameter, and a total annual throughput capacity of 30 Bcm. It includes the following lines with connections to neighbouring countries:

- **Mozdok (Russia) - Kazi Magomed:** Total length 700 km, of which 240 km is in Azerbaijan. The pipe's diameter is 48", and annual throughput capacity is 13 Bcm.

- **Bind - Bland (Iran) - Astara - Kazi Magomed (Igat-1):** Total length 1,147.5 km, of which 296.5 km is in Azerbaijan. The pipeline, built in 1971, has a diameter of 48", 9 compressor stations (3 in Azerbaijan), an operational pressure of 75 bar, and annual throughput capacity of about 10 Bcm. It has been mothballed since 1993.

- **Kazi Magomed - Kazakh (2 lines):** Total length of each line is 378 km. The first, with a diameter of 40", has an annual throughput capacity of 10 Bcm. The second, with a diameter of 48", has an annual throughput capacity of 13 Bcm. There are 3 compressor stations. The operational pressure for both lines is 55 bar.

- **Kazakh - Georgia:** Total length within Azerbaijan is 120 km. The dimension of the pipeline varies between 20", 32" and 40". Operational pressure is 55 bar and total annual throughput capacity is 10 Bcm.

- **Kazakh - Armenia:** Total length within Azerbaijan is 38 km. The dimension varies between 40" and 20", with an operational pressure of 55 bar and an annual throughput capacity of up to 7 Bcm. It has not been in use since 1992.

- **Yevlakh - Nakhichevan (via Armenia):** Total length of this pipeline that connects Azerbaijan proper to the Azeri province of Nakhichevan, which lies on the other side of Armenia, is 350 km, of which 290 km is on Azeri territory. The diameter of the line is about 28". Operational pressure is 55 bar and annual throughput capacity is 4.5 Bcm.

Seven compressor stations are currently in operation in Azerbaijan, and 150 distribution stations. Two underground storage facilities located in depleted oil and gas fields at Kalmas and Karadag have a capacity of about 3 Bcm. According to Azerigaz, these could be expanded to 10 Bcm at relatively low cost. The sites do not contain gas processing or dehydration facilities to separate out the large amounts of water and liquid hydrocarbons absorbed by the gas during storage. Expansion and reconstruction of the storage facilities is reportedly underway.

Azerigaz has 12 regional distribution companies, which allow it to deliver gas to over 1 million customers via some 31,000 km of medium and low pressure distribution lines.[10] This high degree of gasification has been achieved despite some 50% of the population living in rural areas. However, at the end of 1997, due to ongoing gas shortages, only about one third of the network was being supplied, mainly in the Baku region.

10. According to a 1997 Azerigaz brochure, the company serves "65 towns and district centres, 43 small towns, about 2,000 villages, 800 industries and over 13,000 communal properties and social services," including 1.2 million families.

In many areas there are parallel gas distribution systems – a low-pressure network for households, and a medium-pressure one for industries. According to the World Bank, operational efficiency could be improved by eliminating the low-pressure system in such areas.

According to Azerigaz, the gas distribution system suffered from losses of around 8% in 1997, down from 15% a few years earlier. It is estimated that up to two-thirds was due to non-technical losses such as theft and metre tampering. However, these losses were presumably only in the third of the system actually in operation. According to outside experts, the transmission and distribution system as a whole is highly dilapidated. Poor measurement devices and a lack of a modern control and communication systems also impede efficiency.

Another important problem contributing to loss is insufficient cathodic protection of pipelines, combined with the often high quantity of corrosive salts and acids in the Azeri soil. Many pipelines also appear to have been built in unsuitable areas that would be considered unsuitable in OECD countries, for example under buildings and close to main roads and rail crossings.

Total investment needs for rehabilitating the gas transportation system are estimated by Azerbaijan at around US$150 million. The World Bank is to make available US$20.2 million in the first stage of a US$100 million gas industry rehabilitation programme.[11] Priority investments identified under this programme include anti-corrosion measures for pipelines, the purchase and installation of gas metres for large customers, consulting services for a household metering system, and corporatisation of the LPG distribution system. The EBRD and other IFIs may provide additional financing for this programme.

The EC, under its TACIS programme, has provided ECU 2.7 million to Azerigaz for improving accounting systems related to customer services and for rehabilitating and expanding the two gas storage facilities.

According to Azerigaz, the large municipalities will soon take over their respective distribution systems from Azerigaz.

LPG

In addition to distribution by pipeline, Azerigaz is responsible for bottling and distributing LPG, which is produced at four plants: the Novo-Bakinskiy refinery (annual LPG capacity of 90 kt), the Karadag processing plant (30 kt), the Azerigaz NGL processing plant (1.1 kt), and the Sumgait rubber factory, which produces propane and butane as by-products. Some LPG is also imported from Russia.

LPG is dispatched to five bottling plants by rail, and to three others by truck. It is then distributed in bottled form to distribution points and to end-users by road. The wholesale price of LPG was about US$169 per tonne in 1996. According to Azerigaz, LPG operations are profitable, due in part to stricter payment procedures than those for piped gas.

11. Lent via the International Development Association (IDA) for 35 years at an interest rate of 0.75%, with an 11-year grace period.

An increase in demand for LPG is expected in the future, since the delivery system for piped gas may be overextended and may have to be cut back in an effort to rationalise distribution. The government is considering separating LPG operations from Azerigaz and soliciting foreign investment for improving and enlarging LPG operations.

Conoco is reportedly studying the feasibility of exporting Azeri LPG to Turkey.

Gas consumption

Azerbaijan traditionally has met most of its non-transport energy needs with gas. However, total gas consumption fell from 12.2 Bcm in 1990 to about 6.2 Bcm in 1996, largely due to a decline in imports from Turkmenistan and consequent restrictions on consumption imposed by the Azeri government. Gas-saving measures included switching Azerbaijan's dual-fired power generating units from gas to fuel oil and restricting gas use by industry. Industrial use dropped by around 25% between 1993 and 1995.

Table 6 Azeri natural gas consumption (Bcm)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Total	12.190	10.956	11.235	8.881	8.880	7.237	6.239
of which Azenergo	5.474	4.423	1.621	0.817	0.936	1.182	1.440
of which households	2.700	3.100	2.850	3.085	2.686	2.487	1.685
of which industry and other	4.016	3.433	6.764	4.979	5.258	3.568	3.114

Source: Azerigaz.

In 1990 total gas consumption in Azerbaijan was about 12.2 Bcm, of which approximately 5.5 Bcm was used for electricity and heat generation, and 4.0 Bcm consumed by industry. By 1996, total gas consumption had dropped to 6.4 Bcm, of which around 3.1 Bcm was consumed by industry, with only 1.4 Bcm used for electricity and heat generation.[12] Socar uses approximately 1 Bcm annually for its own operations.

Household consumption dropped from 3.1 Bcm in 1993 to 2.5 Bcm in 1995 due to restrictions in supply. Azeri households use gas for cooking, water heating and space heating. The use of gas in the latter two cases is more common in Azerbaijan than in many other parts of the former Soviet Union. Elsewhere in the FSU, hot water and heat are often supplied through district heating systems.

As of 1993, only half of industrial gas consumers were equipped with metres, while there were no metres for individual households. Lack of metres makes it difficult to control flows, as well as to develop a pricing and incentive policy based on amounts consumed. Most residential consumers are currently charged according to a formula based on household floor space, number of persons, and assumed consumption rates of various appliances.

12. In 1997 about 30% of electricity generation was by gas during the Summer, and 70% by mazut. During the Winter, all electricity and heat was generated by mazut in order to deliver more gas to households for heating.

A programme to install household gas metres in Baku began in 1994, and by the end of 1997 some 39,000 metres had been installed out of approximately 450,000 households in the capital. The priority has been to install metres in households that both heat and cook with gas. The Cabinet of Ministers has ordered gas metres to be installed in 535,000 households by 2008, out of approximately 1.2 million total households in the country. This is to include metering of almost all households in the metropolitan areas of Baku, Ali Bayramli and Sumgait. According to Azerigaz, pre-paid metres will be tested on a number of private small businesses.

Gas pricing

Gas prices are controlled by the government. In 1996 Socar sold gas to Azerigaz for the equivalent of US$10.80 per thousand cubic metres (US$9 to Socar plus a 20% royalty to the government), while the nominal price of gas imported from Turkmenistan was US$80 per thousand cubic metres.[13] Industrial consumers paid Azerigaz US$53.30 per thousand cubic metres, communal users paid US$23.60, and the residential sector only US$2.80 (raised from approximately US$1.40 in June 1996).

In 1997, Socar raised the price it charges Azerigaz to approximately US$22 per thousand cubic metres. However, Azerigaz's sales prices did not increase significantly from 1996 levels. The notable exception was the price of gas to households, which rose to about US$6 per thousand cubic metres.

In its negotiations for a gas rehabilitation loan from the World Bank in 1996 and 1997, the government agreed to review its gas pricing system, taking into account its investment goals and the needs of potential foreign investors to make an adequate return on capital. In particular, the government is to raise residential gas prices on a quarterly basis.

Non-payment for gas

Like many other utilities in the former Soviet Union, Azerigaz has been strongly affected by the non-payments crisis. As of April 1997, the company was owed 612 billion manats (about US$145 million). However, this was down some 130 billion manats from September 1996. Azerigaz in turn owed 385 billion manats, mainly to Socar. Major debtors to Azerigaz include state-owned power producer Azerenerji and the Azerkhimiya state chemical plant.

In April 1997, Azerigaz announced that it would move to a pre-payment system for ministries and other government departments.

GAS TRADE

Between the mid 1970s and mid 1980s Azerbaijan produced a small gas surplus (around 2 Bcm), which it exported to neighbouring Soviet republics. In the late 1980s and prior to 1992, Azerbaijan imported 13 - 14 Bcm per year, of which 5 - 6 Bcm was re-exported to Armenia and

13. According to the World Bank, since much of Azeri payment is made in barter, the effective price may have been closer to US$43. Figuring in the 15% losses in the Azeri transmission network makes the wholesale prices from Socar and Turkmenistan around US$12.40 and US$49.50 per thousand cubic metres, respectively.

Georgia. By 1992 total gas consumption in Azerbaijan was 11.2 Bcm, of which about 4.3 Bcm was imported, with an additional 1.0 Bcm imported for re-export to Georgia. (Re-exports to Armenia ended in 1992.) By 1996, total gas consumption dropped to 6.2 Bcm, of which only 2.4 Bcm was imported, with almost no gas exported.

Iranian gas was sent to Azerbaijan through the Iranian Gas Trunkline (Igat), which runs from central Iran to the Azeri border. Igat was built in 1971 to supply gas to the Soviet Union as part of a swap arrangement under which Iranian gas could be sold to Europe. Annual throughput capacity was 10 Bcm, although actual volumes were reportedly never as large as planned, and only reached some 3 Mt in 1991. The volume imported from Iran reportedly dropped to below 1 Bcm in 1992 due to Azerbaijan's inability to pay the higher prices demanded by the Iranians. Igat is currently mothballed, though the Lenkoran/Talysh Deniz offshore oil project operated by Elf Aquitaine has considered converting the pipeline to export oil to Iran.

In 1992 Azerbaijan began importing gas from Turkmenistan, which subsequently remained its main supplier through 1995. Since Turkmen gas must traverse Uzbekistan and Russia (including Chechnya) in order to reach Azerbaijan, disputes between Turkmenistan and Russia over the use of Russia's Gazprom pipeline system led to a number of security of supply concerns. However, the inability of Azerbaijan to finance its gas imports proved a greater problem. Imports from Turkmenistan are estimated by the IEA to have been about 2.8 Bcm in 1992, 2.3 Bcm in 1993, and 2.5 Bcm in 1994. In 1994, imports from Turkmenistan were restricted by mutual agreement between the Azeri and Turkmen governments due to the inability of the Azeri side to pay for them.[14] Turkmen imports dropped to about 0.6 Bcm in 1995, and ceased altogether after the first quarter of that year.

In March 1996, the Azeri government announced it would discontinue all imports of gas and concentrate on developing its own resources in the Caspian Sea. A study by Azerigaz claims that the exploitation of new fields plus an overhaul of the gas supply system, including the upgrading of compressor stations, could make the country self-sufficient in gas sometime between 2000 - 2005.

Gas transit

In 1991 some 6.0 Bcm of natural gas was re-exported to Armenia and Georgia out of total imports of 14 Bcm. Re-exports to Armenia stopped in 1992 due to the conflict over Nagorno-Karabakh.

The World Bank has estimated that Azerbaijan could potentially earn transit fees of US$5 - 8 million per Bcm crossing its territory. Assuming a resumption of re-exports of around 6 Bcm per year to neighbouring countries, this could amount to some US$30 - 48 million in yearly transit fees. With the construction of a proposed trans-Caspian pipeline, transit of gas from Kazakstan and Turkmenistan could conceivably increase by an additional 20 Bcm, representing some US$ 100 - 160 million in annual transit revenues.

14. By the time of the cutoff in 1995, Azerigaz had incurred a debt of US$81 million, which it agreed to pay off over a four-year period, mostly by barter.

Ukraine signed an agreement with Iran in 1992 to import Iranian gas via Azerbaijan. However, discussions have stalled over Ukraine's ability to pay. Reportedly, there also have been difficulties gaining transit rights for the gas in Russia, through whose territory the gas also must pass.

INVESTMENT

Total foreign investment for 1996 is estimated at around US$250 million, of which approximately half was in the oil and gas sector. An estimated additional US$400 was invested in the sector in 1997, and the government expects over US$750 million in 1998. Contracts signed with foreign oil firms by the beginning of 1998 represent over US$30 billion in new capital to be invested in Azerbaijan in the coming years. According to the Azeri Ministry of Economics, total foreign investment per capita in Azerbaijan in 1997 was US$267, the highest figure for any FSU state.

Major offshore oil and gas deals with foreign investors have been conducted as production sharing agreements (PSAs). Due to the lack of oil and gas sector legislation, each PSA is approved by the parliament as a separate law. Such an ad hoc method has allowed Azerbaijan to learn from previous deals and to extract more favourable terms with subsequent agreements. By the end of 1997, Azerbaijan had signed over eight PSAs. Azerbaijan has been careful to include companies from many countries in its projects, including neighbouring Russia, Turkey and Iran, as well as the US, UK, France and Japan.[15]

Table 7 Socar's share in offshore PSAs

Block	Consortium or main foreign partner	PSA signature date*	Socar's share
Azeri, Chirag, Guneshli	AIOC	1993	10%
Karabakh	CIPCO	11/1995	7.5%
Shakh Deniz	BP/Statoil	6/1996	10%
Dan Ulduzu	NAOC	12/1996	20%
Lenkoran Deniz	Elf	1/1997	25%
Yalama	Lukoil	7/1997	40%
Oguz	Mobil	8/1997	50%
Apsheron	Chevron	8/1997	50%
Nakhichivan	Exxon	8/1997	50%
Inam	Amoco	8/1997	50%
Kyurdashi	Agip	9/1997	50%

* Ratification by Azeri parliament typically several months later.

15. Companies participating in offshore oil projects with Socar include Amoco, Exxon, Pennzoil and Unocal of the US; British Petroleum and Ramco of the UK; Statoil of Norway; Agip of Italy; TPAO of Turkey; Itochu of Japan; Elf and Total of France; Deminex of Germany; Petrofina of Belgium; Lukoil of Russia; OIEC of Iran; and Delta of Saudi Arabia.

Section 907

In connection with the Nagorno-Karabakh conflict, the United States Congress has restricted aid to Azerbaijan. Section 907 of the Freedom Support Act of 1992 prevents the United States government from offering to the government of Azerbaijan many kinds of assistance that it provides other FSU governments. Section 907 reads in part that US assistance "may not be provided to the government of Azerbaijan until the President determines, and so reports to Congress, that the government of Azerbaijan is taking demonstrable steps to cease all blockades and other offensive uses of force against Armenia and Nagorno-Karabakh." The Clinton administration, like the Bush administration before it, opposes this restriction of US assistance.

The FY 1998 Foreign Operations Appropriations bill and accompanying conference report passed in 1997 allows the US Overseas Private Investment Corporation (ODIC) to provide guaranteed loans and risk insurance, and the Trade and Development Agency (TDA) to fund feasibility studies for oil companies' operations in Azerbaijan. Such assistance could reportedly be crucial to many smaller American companies interested in involvement in the Azeri petroleum sector.The US Export-Import Bank is not affected by Section 907 restrictions.

Offshore investments

Most major deals with foreign investors have been offshore. These include the following:

Azeri, Chirag and Guneshli

In June 1991, Amoco was granted the right to negotiate for the development of the Azeri field. In September 1992, BP/Statoil won an agreement for Chirag, and in October 1992 Pennzoil and Ramco won rights for the deep water portion of the Guneshli field. In 1993, Azerbaijan unitised these three concessions. The foreign companies, led by an alliance of BP (UK) and Statoil (Norway), formed a consortium whose operating arm became the Azerbaijan International Operating Company (AIOC). Shares in AIOC have changed over time. As of 1 January 1998 they were as follows:

BP (UK)	17.13%
Amoco (US)	17.01%
Exxon (US)	8.00%
Pennzoil (US)	4.82%
Unocal (US)	10.05%
Ramco (UK)	2.08%
Statoil (Norway)	8.56%
TPAO (Turkey)	6.75%
Socar (Azerbaijan)	10%
Lukoil (Russia)	10%
Itochu (Japan)	3.92%
Delta-Nimir (Saudi Arabia)	1.68%

Azerbaijan had originally intended to sell some of its shares to Iran, but was prevented from doing so by the opposition of the US companies involved in the project.

Total recoverable reserves of the three fields were originally estimated at 400 - 511 Mt. Evaluations carried out in mid-1997 raised the total to 650 Mt, while the Azerbaijani Academy of Sciences' Geology Institute claims that recoverable reserves could be as high as 800 Mt.

"Early production" began in late 1997. As of February 1998, oil was flowing to the Sangechal terminal on the Apsheron peninsula from three wells, all at the Chirag field. Eight of the planned 24 wells at Chirag are to be drilled in 1998.[16] Production is expected to reach 30 kb/d in 1998 and 115 kb/d by 2000. As other fields come on-stream, production is expected to reach 300 kb/d by 2004. By 2010, AIOC should reach a peak production of 700 kb/d, which is expected to last for four years. Some 500 kb/d of peak production is earmarked for export. Revised plans being reviewed by AIOC reportedly could lead to production of 800 kb/d as early as 2006.

"Early oil" is to be exported via two pipelines: one to the Russian Black Sea port of Novorossiysk, and the other to the Georgian Black Sea port of Supsa. The Novorossiysk line opened at the end of 1997, and the Supsa line is expected to be completed by the end of 1998. A larger pipeline for the so-called "main oil" flows will probably be required by 2003. The route for this pipeline is to be decided by the end of 1998. (See section on AIOC pipelines.)

Socar has rights to all associated gas in Azerbaijan, including at the AIOC fields. Socar estimates that it will cost US$11 million to develop the 55 Bcm of associated gas it says are recoverable in the AIOC contract area. Estimates of recoverable non-associated gas at AIOC fields are as high as 90 Bcm. Gas produced so far has been pumped by underwater pipeline to the gas processing facility located offshore at Neft Dashlari. AIOC plans to build a new pipeline from the AIOC fields to the onshore Sangachal terminal.

Total development costs for the fields, not including pipelines, are estimated at US$13.3 billion over 30 years. The AIOC spent some US$126 million in 1995, of which about 15% went to Azeri contractors. In 1996 total expenditures were around US$ 416 million (plus a further US$36.6 million in bonuses), of which about 20% went to local firms. The budget for 1997 was around US$569 million, with a similarly large portion earmarked for Azeri contractors.[17]

AIOC paid US$203 million in bonuses to the government between 1993 and 1995. Some US$40 million in additional bonuses are to be disbursed in tranches during 1996 - 1998, with the remainder tied to progress in implementing the contract. Socar's share of the profit oil is to be 15% during the initial stage of the project.

Karabakh

Azerbaijan's second international consortium is the Caspian International Petroleum Company (CIPCO), which is exploring the offshore Karabakh structure and surrounding region. The licence area is 427 km^2 in 160 - 225 m of water in the northern part of the Azeri sector of the

16. The production wells are being drilled by Canadian-German consortium Kenting/Deutag, using the Chirag-1 platform.
17. Contracts during 1995 and 1996 were split as follows: Azeri companies and affiliates US$114 million, UK companies and affiliates US$120 million, US companies and affiliates US$108 million, Japanese companies US$58 million, German companies US$39 million, Dutch companies US$29 million, Italian companies US$30 million, Norwegian companies US$14 million, Finnish companies US$11 million. (Petroconsultants 6/97)

Caspian, about 80 km from shore. Estimated oil reserves are reportedly 68 - 150 Mt. A successful exploration programme will ultimately lead to first oil production in 2001. Peak production could reach 200 kb/d after 4 - 5 years.

The CIPCO consortium, created in November 1995, includes Pennzoil Caspian Development Corporation (30%), Lukoil International Ltd. (12.5%), Agip Azerbaijan B.V. (5%), Luk-Agip (45%) and a SOCAR affiliate (7.5%). A three-year exploration programme began in February 1996. It includes 3-D seismic work, the drilling of three wells, and an environmental evaluation. Total investments for 1996 were US$8 million. A 1998 budget of about US$59 million includes the drilling of two more exploration wells. The first exploration well (KPS-1), drilled to a depth of 3,840 m, revealed a gas accumulation, the extent of which is to be evaluated it the second and third wells. The second well, on which drilling will start in April 1998, will be located 6 km northwest of the first one and is to reach a depth of 4,000 m. Drilling on the third well is planned for late 1998.

Shakh Deniz

The Shakh Deniz field is located in the southeast part of the area offshore Azerbaijan in depths of 60 - 550 metres. Estimates of recoverable reserves are 100 - 200 Mt of oil, 400 Bcm of gas and 200 Mt of gas condensate.

A consortium led by the BP/Statoil alliance was formed in June 1996 to develop Shakh Deniz. Both BP and Statoil have 25.5%. Elf Aquitaine (France), Lukoil (Russia), Socar, and OIEC (Iran) have 10% each, and Turkish Petroleum Corporation has 9%. BP Exploration Shakhdeniz is the project operator. Socar's share of the profit oil will be 50% in 2004, falling to 24% by 2015.

The consortium expects to invest a total of US$2 - 4 billion. Some US$100-150 million of this will be spent during the first three years of operation, mainly on seismic work and completion of three exploration wells. Two exploration wells are expected to be drilled in October 1998, and production is to begin three years after a three-year exploration phase.

The bonus paid to Azerbaijan was reportedly only US$10 million, although the foreign investors have agreed to finance Socar's share in the project.

It remains to be seen whether the participation of Iran in this project will present complications for the use of export infrastructure built in part by American firms (e.g., the AIOC pipelines).

Dan Ulduzu and Ashrafi

The Dan Ulduzu and Ashrafi fields are located approximately 20 km northeast of the AIOC fields in 80 - 100 metres and 150 - 180 metres of water, respectively, with likely deposits occurring at 4,000 metres. Estimated reserves of the two fields total 100 - 120 Mt of oil and 30 - 50 Bcm of gas.

The North Apsheron Operating Company (NAOC), a consortium of international oil firms led by Amoco (US), signed a PSA with Azerbaijan in December 1996 to develop the Dan Ulduzu and Ashrafi fields. The PSA was ratified by the Azeri parliament in February 1997. The NAOC consortium is split 30% to Amoco, 30% to an alliance of Unocal (US) and Delta (Saudi Arabia; 25.5% and 4.5%, respectively), 20% to Itochu (Japan) and 20% to Socar. The foreign companies are to carry 100% of Socar's share during exploration, and may carry a proportion during production. According to then Socar Vice President Rafik Abdullayev, the relatively large share given to US companies in the project was meant in part as compensation for their exclusion from the Shakh Deniz project due to Iranian involvement. This was the first project offshore Azerbaijan in which no Russian companies took part, although Azerbaijan has discussed combining this project with the Karabakh one, in which Lukoil is the main shareholder.

Under the 1996 agreement, the NAOC will explore for three years, drill three appraisal wells and carry out environmental studies. (As of the beginning of 1998 the consortium was drilling its first appraisal well.) If the consortium finds commercial hydrocarbons it will produce a development plan and begin exploitation within 24 months of the plan's approval by Socar. The development phase is to be 25 years with an optional five-year extension. Production is forecasted to begin in 2003 and reach 140 kb/d by 2007. Estimated investment needs for the two fields are US$1.5 - 2.5 billion. NAOC reportedly paid a signing bonus of US$75 million.

Socar's share of the profit oil will vary between 50 - 85% depending upon the internal rate of return for the project. As in other projects, associated gas will belong to Socar.

Lenkoran Deniz and Talysh Deniz

The 422 km^2 project area lies 100-120 km south of Baku, near the Iranian sector. It is some 50 km from shore in 20-120 metres of water, with potential deposits lying at around 4,000-4,500 metres. Recoverable oil reserves are expected to be around 50 Mt.

Elf Aquitaine and Total signed a PSA with Socar in January 1997 to develop the Lenkoran Deniz and Talysh Deniz fields, located offshore Azerbaijan in the Caspian Sea. The contract was approved by the Azeri parliament and entered into law in June 1997.

The equity was originally divided 40% to Elf, 10% to Total, and 25% to Socar. The remaining 25% was allocated by Socar in May 1997 as follows: Oil Industries Engineering and Construction Overseas Ltd (Iran)[18] was given 10%, Deminex (Germany) 10%, and Agip (Italy) 5%. Elf subsequently sold 5% of its 40% stake to Petrofina (Belgium) in May 1997. Elf Aquitaine acts as operator for the project, which is estimated to cost US$1.5-2 billion to develop.

The exploration programme is expected to last three years and will include 3-D seismic and two wells. Commercial production is forecast to begin in 2004 and last for 30 years, with output peaking at 300 kb/d. Much of the oil produced may be sent for refining via the mothballed Igat-1 gas pipeline to Iran's underutilised Tabriz and Tehran refineries. Igat-1 runs within 100 km of the project, though would have to be converted to carry oil.

18. OIEC is privately held Iranian company, of which 40% is owned by the National Iranian Oil Company. OIEC also holds a stake in the Shakh Deniz project.

One of the attractive aspects of this deal to the Azeri side was the 25% share given to Socar, which was relatively large compared to previous projects. Moreover, Socar's part is to be financed 100% by the foreign partners during exploration, and perhaps partially during production. (Under all previous contracts, Socar had to finance 100% of its share during production.) Bonuses were also higher than under previous contracts, with a first tranche of US$10 million paid one month after the contract came into force, a second tranche that is to be paid after commercial reserves are determined (US$2.5 million for each 100 million barrels), and a third tranche of US$10 million at the start of production. Royalty rates are US$22,500 per square km (compared with only US$1,200 for the Dan Ulduzu/Ashrafi project).

Yalama

Section D-222, also known as the Yalama field, is a 30-km by 20-km block lying some 10 km offshore Azerbaijan near the Russian border. Preliminary data suggest reserves of 50 - 70 Mt lying at depths of 3,000 - 4,000 metres and that Yalama is a continuation of a promising structure offshore Russia that is already being explored by Lukoil. Development expenses are expected to be around US$70 million.

Lukoil's PSA to develop the Yalama field with Socar was signed in July 1997 and ratified by the Azeri parliament in November 1997. Under the terms of the agreement, Lukoil will control 60% of the project, and Socar the remaining 40%. In early 1998 Lukoil transferred its share to Lukarco, a joint venture set up between it and Atlantic Richfield (US) in 1997.[19] This was the first oil and gas project in Azerbaijan in which a single foreign firm owned more than a 50% share. The 40% share in the project reserved for Socar was also larger than usual.

The project is estimated to require a total investment of around US$2 billion. Lukoil is to finance 100% of the geophysical exploration, which is expected to cost around US$70 million. The exploration phase is to last four years.

Oguz

The 227-km^2 Oguz block is located immediately south of Neft Dashlari and the AIOC project fields, about 100 km east of Baku. Reserve estimates for Oguz are 40 Mt of oil and 20 Bcm of gas.

Mobil (US) signed a PSA with Socar in August 1997, which the Azari parliament ratified in November 1997. Both companies are to own 50% of the project, with Mobil as operator. Exploration drilling is to be completed by 2000. Mobil is also negotiating for the nearby D-30 structure.

Apsheron

The 400-km^2 Apsheron (formerly Zeinalabdin Tagiyev or D-2) block is located 40 km southwest of the AIOC fields in 300-650 metres of water, with deposits likely occurring at

19. Lukarco is also involved in the Tengiz field development and the Caspian Pipeline Consortium (CPC) in Kazakstan.

4,800 - 7,100 metres. Reserves are estimated at 115 Mt of crude oil, 200 Mt of condensate, and 400 Bcm of gas. The exploration area is 205 km^2.

Chevron, which signed a PSA for the field in August 1997, holds a 30% interest in the project and will be the operator. Total (France) acquired a 20% share in September 1997. Socar plans to retain 50% of the shares in Apsheron. The foreign companies are expected to cover 100% of Socar's costs during the exploration phase, and a portion during development. Chevron estimates total investment required at US$8 billion. Shooting of 3-D seismic and evaluation drilling is to begin by the end of 1999.

Nakhichivan (D-3)

The 280-km^2 Nakhichivan block (also known as the D-3 structure) is located in the Baku Archipelago south of the Shakh Deniz field, in water depths of 100 - 500 metres. Recoverable oil reserves are estimated at about 100 Mt occurring at depths of around 5,000 metres. Significant gas condensate deposits are expected.

Exxon (US) signed a PSA with Socar in August 1997; the deal was ratified by the Azeri parliament in November 1997. The American company has a 50% stake and acts as operator. In February 1998 Caspian Geophysical began a 3-D seismic survey under a contract reportedly worth US$9 million. Total investment in the Nakhichivan project is expected to be around US$2.5 billion.

Exxon signed a memorandum of understanding in June 1996 with Socar to develop this field, along with the nearby D-9 and D-38 blocks; it is still holding discussions with Socar regarding the latter blocks.

Inam

The Inam field is located 50 - 70 km north of Lenkoran and 50 km from the coast, adjacent to the Shakh Deniz field, in 50 - 200 metres of water. Reserves are estimated at 120 - 300 Mt, with reservoirs expected at 4,000 - 4,200 metres.

Amoco signed a development agreement with Socar in August 1997. Development of the field is expected to require an investment of US$1.5 - 2.5 billion. Socar had previously indicated it would develop the field itself, as it is one of the few major undrilled structures lying at depths readily accessible to Socar's existing technological capabilities.

Kyurdashi

The Kyurdashi block is located in the southern part of Azerbaijan's Caspian sector and contains the Kyurdashi, Araz-Deniz, and Kirgan structures, lying in 50 - 500 metres of water. Estimated oil reserves are 90 - 100 Mt.

In September 1997 Agip (Italy) signed a PSA to develop the block, in which the Italian company will have a 25% interest. Other companies may be given up to 25% of the shares. Mitsui reached an agreement to take 15% in March 1998, and Texaco (US) is also reportedly interested. Socar plans on retaining 50% of the shares.

Major offshore deals under negotiation

South Caspian Archipelago

In late 1996 Mobil (US), Ramco (UK) and Total (France) formed a consortium to explore for oil in the shallow waters of the South Caspian Archipelago region. The consortium, which is to be called MRT Energy, consists of Mobil with 40% of shares, Total with 40%, and Ramco with 20%. MRT expects to begin exploration drilling in 1998.

Shallow Guneshli

The Guneshli field, of which the shallow portion is so far the only part under production (the deeper southeastern part of Guneshli is to be developed by the AIOC) accounted for some 60% of Azeri oil output in 1997, though has been in a steady decline due to falling pressure. Output in 1997 from the field's 12 production platforms was about 100 kb/d. Remaining recoverable oil reserves in the shallow portion are estimated at 30 - 71 Mt.

Following a memorandum signed in November 1996, Conoco (US) and Ramco (UK) are negotiating a risk service contract with Socar to maintain pressure in the shallow water portion of Guneshli using gas lift and water flood technology. This could be the first risk service contract in Azerbaijan.

Yanan Tava-3, Atashgah and Mugan Deniz

The Yanan-Tava, Atashgyakh and Mugan Deniz fields are located about 30-40 km offshore in water depths up to 120 metres. Petroleum structures are estimated at about 1,000 metres, with potential liquid reserves of about 137 Mt.

Japan National Oil Corporation (JNOC) heads a group of mainly Asian investors that signed a memorandum of understanding with Socar in March 1997 to explore the three fields. The group includes Itochu, Indonesia Petroleum, Japan Petroleum Exploration and Teikoku Oil. The proposed contract area is 500 km^2 and anticipated investments are on the order of US$4 billion.

Umid

Socar is negotiating with a number of companies, including Chevron, Exxon and Occidental, for development of the Umid field, which is located some 50 km south of Baku. Umid may be largely gas bearing, with estimated reserves of 300 Bcm.

Abikh Bank

The Abikh Bank contains a group of structures in the southern portion of Azerbaijan's offshore section of the Caspian Sea (D-12, D-13, D-15 and D-19). BP is reportedly negotiating an E&P contract for this area.

Kyapaz

The Kyapaz field, which lies within an area disputed by both Azerbaijan and Turkmenistan, is estimated to contain 50 Mt of oil. A preliminary agreement to pursue a PSA was signed by Russian companies Lukoil and Rosneft with Socar in July 1997. Socar was to hold 50% of the shares, with Lukoil taking 30% and Rosneft 20%. The preliminary deal was denounced by the Turkmen Ministry of Foreign Affairs soon after it was signed.[20] It was put on hold in 1997 by the Russian companies.

Offshore tender

Socar has announced a tender, tentatively scheduled for the first quarter of 1998, for the redevelopment of a number of offshore fields, including Bahar, Bulla Deniz, Neft Dashlari, Palcig Tepe, Sangachali Deniz, Duvanyy Deniz, and Khere Zyrya (Ostrov Bulla). The British consulting firm MAI has been hired to evaluate the fields, some of which already have been under active negotiations with foreign investors. (It is not yet clear how these will be included in the tender.)

Onshore investments

Development of Azerbaijan's onshore oil reserves, which began in the 19th century, is well advanced and facing significant production declines. Preliminary studies suggest that production could be increased at existing wells with the introduction of new technology, and at a lower cost per additional barrel than at most new offshore developments. Large foreign investors have preferred to stay offshore, however, primarily due to the unattractive onshore terms offered so far by the government.

The main disadvantage of onshore projects has been the reluctance of the government to offer PSAs. Almost all onshore deals so far have been joint ventures (JVs), under which the basic tax rate is 35%, as opposed to the 25% offered under most offshore PSAs. JVs are also subject to other taxes normally excluded from PSAs. Another complication is the uncertainty regarding responsibility for past environmental damage that exists at almost all onshore oil fields.

Most private investment in onshore oil fields has been by small companies, which typically are able to inject enough capital to pay workers and repair existing equipment, but usually do not have the resources to invest in the new technology needed to significantly increase output. As a result, few onshore projects have produced much over the "base" output that existed before the private investment.

Apparently in reaction to the disappointing results achieved under early onshore projects, the Azeri government now appears to be considering changes to the onshore investment regime, including the use of PSAs.

Socar, together with Schlumberger's GeoQuest, ran a series of seminars beginning in July 1997 to promote onshore opportunities in Azerbaijan. Socar's preferred option is for foreigners to

20. In early 1992 Turkmen President Niyazov also laid claim to the Azeri field and part of the Chirag field, which are being developed by the AIOC. Kyapaz, which was called Promezhutochnaya during Soviet times, is referred to as "Serdar" field by the Turkmenis.

invest in two existing Azeri field management companies, Bibi-Eybat and Tagiev.[21] It also said it would like risk sharing contracts, but would be willing to entertain other offers. Socar stated in 1997 that it now considers the JV formula less relevant to its current investment needs. Nevertheless, most of the onshore projects involving private investors as of the beginning of 1998 were joint ventures.

BMB Oil, a JV in which Birlesmis Muhendisler Burosu (Turkey/US) owns 49%, is carrying out exploration work on the west Apsheron peninsula and developing the North Karadag, Kergez-Kyzyltepe and Umbaki fields. Estimated remaining reserves are 30 - 60 Mt. A six-year exploration term is to be followed by a 20-year production period. Total development costs are estimated at US$300 million. BMB plans to apply to the EBRD for a US$60 million loan to continue work on the project, which produced about 161 b/d in 1996. BMB was formed as a PSA in August 1994, though as of the beginning of 1998 the PSA had not been approved by the Azeri parliament.

Anshadpetrol is a JV in which Attilla Dogan (Turkey) holds 31.8% of shares, Land and General (Malaysia) 17.2%, and Socar 51%. Socar took over as operator from Attilla Dogan in March 1997. Anshadpetrol produced 760 b/d in 1996.

Azergermoil is a JV in which Grunewald (Germany) holds 49%. Azergermoil produced 1.2 kb/d in 1996.

Azerpetoil, a JV in which Pet Oil (Turkey) holds 49%, is developing the Kalamadin field, which reportedly has reserves of 6.7 Mt, as well as the Kichik and Byuk Kharami fields. Azerpetoil produced 2.6 kb/d in 1996.

Shirvan Oil, a JV formed by White Hall (UK), was formed in September 1997 to develop the Kyurovdag field, which reportedly has a reserve base of 120 Mt. This JV is unique in that some of its terms resemble those of some Azeri PSAs. For example, until White Hall recoups its intended US$300 million investment, it will receive 60% of oil production above the base level of 4.4 kb/d (as opposed to 49% of profits, as would be the case under most previous onshore JVs). Shirvan aims to increase production to 7.3 kb/d.

Onshore projects under negotiation include an alliance of Commonwealth Oil and Gas (Canada) and Union Texas Petroleum (US) to develop the Southwestern Gobustan block. Located 300 km southwest of Baku, the block has estimated reserves of 100 Mt of oil and 14 - 26 Bcm of gas. Operations at the field were terminated in the early 1970s. As of late 1997 the alliance of was negotiating the terms of an onshore PSA with Socar. The alliance, which will develop shut-in fields and explore new acreage, will reportedly receive 80% of production, with the remaining 20% going to Socar. Total investment over 25 years is expected to reach US$750 million.

Ramco (UK) has exclusive rights to negotiate for the development of a 3,110-km^2 area in the Lower Kura basin that contains the Muradkhanli field. Ramco has been negotiating a PSA for the project since 1994. Reserve estimates are 3 Mt of oil.

21. The Bibi-Eybat NGDU operates the Bibi-Eybat oil field, one of the oldest in the world. The field produced only 5 b/d in 1996 with a water cut of 92%. Remaining oil reserves are estimated by Socar at 10.3 Mt. The Tagiev NGDU operates the Buzovni-Mashtagi, Kala, and Zirya fields, which together produced 7 b/d in 1996 with a water cut of 88%. The combined reserves of these three fields are estimated by Socar at 15.6 Mt.

Legislation

Due to a lack of petroleum and investment legislation, most of the major international oil and gas development projects currently operating in Azerbaijan were created as PSAs on the basis of tailor made government decrees subsequently approved as separate acts of parliament. The government intends to gradually develop petroleum legislation to standardise some terms of licences that are currently negotiated and included in PSAs, though such laws would presumably not affect existing PSAs. All laws exept PSAs are made public after passage by parliament.

As of the beginning of 1998 the main law dealing with natural resources was still the 1977 code passed by the country's previous Soviet government. In November 1996 the State Committee for Ecology and Natural Resources submitted a new bill on exploiting mineral resources, and in May 1997 a working group of government, parliament and Socar representatives presented a revised version of the bill to parliament. Issues covered by the draft include:

- types of licenses that may be awarded;[22]
- organisation of licensing rounds and tenders;
- taxes, royalties and other payments; and
- regulations for operating projects, including environmental guidelines.

SOCAR also has submitted a draft petroleum law, and a law on gas transport is under discussion.

Rights to land

At the dissolution of the Soviet Union, all land belonged to the State. Private ownership and other rights of tenure have since been introduced. Although the Land Code of 9 November 1991 states that no land may be owned by foreign legal entities, land plots may be given for purposes of permanent use to joint ventures with foreign participation.

Corporate bodies wholly or partially owned by foreign investors may obtain term leases, though the Law on Leasing of 1992 states that they must secure the lease from the owner of the property (e.g., the State), whereas national legal persons may sub-lease from whomever is currently using or controlling the property.

Investment protection

The Law on the Protection of Foreign Investments allows enterprises with foreign investments to exercise any type of activity not prohibited by law. It also includes the following safeguards for foreign investors:

- The legal regime for foreign investors' activities shall not be less favourable than that for legal persons and citizens of Azerbaijan, except in cases envisaged by prevailing legislation.

- If a future law provides for less favourable investment conditions, foreign investments will by governed by the legislation prevailing at the moment the investment was made.

22. Several types of licenses are envisioned, including for geological study (5 years), production (25 years with possible extensions), and construction and operation of facilities.

- Foreign investments shall not be liable to nationalisation, except in cases of "detriment to the people and national interests of the Republic of Azerbaijan"; or requisitioned except in circumstances of force majeure, such as natural disasters or other situations of an emergency nature.

- In the event of nationalisation or requisition, a foreign investor must receive immediate and adequate compensation at least equivalent to the actual value of investment at the date of the decision to nationalise or requisition it. The compensation must be made in foreign currency and be transferrable abroad.

- When an international treaty signed by Azerbaijan establishes procedures other than those inscribed in the law, the regulations of the international treaty apply.

The law enables foreign legal and natural persons to invest in Azerbaijan through

- ownership in enterprises and organisations established jointly with legal persons or citizens of Azerbaijan;

- incorporation of enterprises fully owned by foreign investors;

- acquisition of enterprises, shares in enterprises, buildings and other structures, stocks, bonds and other securities; and

- acquisition of rights for the use of land and other natural resources.

Concessions/licensing regime

Article 40 of the Law on the Protection of Foreign Investment allows foreign investors to acquire exploration and development rights, provided they have signed a concession agreement with the government and that it has been ratified by parliament.

The government advertises opportunities for new concessions and invites tender applications. In principle, all oil and gas fields at depths of at least 120 metres and all projects for the enhancement of producing fields are open for application; in practice, resources to deal with development applications are limited. The winner of the tender is invited by Socar to negotiate detailed terms, which subsequently must to be approved by the Cabinet of Ministers and the President before ratification by parliament. There are therefore several occasions when negotiations can be reopened and new players brought into negotiations.

Both the terms of a concession agreement and the area covered are determined by the agreement, which usually includes clauses governing the

- procedures and amounts of concession payments;

- environmental obligations;

- rights and duties of the concession holders and of officials participating in the management of the concession;

- terms of financial support for the infrastructure, and

- duration of the concession.

According to the Law on the Protection of Foreign Investment, the territory defined in a concession agreement is considered a "free economic zone", with applicable fiscal and customs provisions determined by a specific decree of the Cabinet of Ministers. Such provisions are in principal a matter for negotiation.

Privatisation

Under the current Privatisation Programme, "medium sized enterprises" and "enterprises in a critical situation" (the energy sector is considered part of the latter category) are to be transformed into wholly state-owned joint stock companies for possible privatisation later. Privatisation of state-owned joint stock companies is to be implemented through consecutive reductions of the State's share in the authorised capital. A "golden share" is to be maintained by the State only in exceptional circumstances, in cases of natural monopolies, or when considerations of national security and public health are involved.

The Law on Privatisation of State Property empowers the President, on the advice of the State Committee on Property, to decide on the privatisation of the energy sector as well as the participation of foreign investors in such privatisation. As of March 1998 a decision to privatise the sector had not been made. Moreover, the Privatisation Programme for 1995-1998 does not envision privatisation of enterprises and conglomerates of the fuel and energy complex, with the exception of related construction organisations.

Privatisation – general procedures

The State Committee on Property approves the privatisation plans of individual enterprises. Under a privatisation plan, shares of a joint stock company are typically distributed as follows:

- 15% for preferential sales, e.g. to the workforce;

- At least 50% for privatisation voucher auctions;

- 10-20% for cash auctions;

- Up to 25% for specialised sectoral and inter-sectoral investment funds. (The Privatisation Programme envisages that some of the shares held by the investment funds will be sold on foreign stock markets.)

The Law on Privatisation of State Property and the State Privatisation Programme for 1995 - 1998 do not contain any special conditions regarding the participation of foreign investors, except that acquisition by a foreign investor of privatisation vouchers or of shares in privatised enterprises may only be done upon redemption of State Privatisation Options. An Option is a bearer's instrument that gives a foreign investor the right to acquire a privatisation voucher. An Option, valid for three years, is redeemed together with a privatisation voucher when registering a purchase transaction with the National Depository System. The system of Options is understood to be concerned primarily with maintaining statistics on the amount of foreign investment.

Transaction payments are settled with foreign investors (both resident and non-resident) in Azeri currency or by privatisation vouchers, subject to the presentation of Options for redemption.

Shares of a joint venture owned by state enterprises (including those registered abroad) are to be excluded from the assets of privatised enterprises. Privatisation of such shares is to be implemented separately by the State Committee on Property through sales at open auctions.

Limitations on privatisation may be introduced by the State holding a control portfolio (51%) or blocking portfolio (25.5%) of voting shares, or a "golden share". Possession of the golden share ensures the State a veto power concerning decisions of a joint stock company for which a three-fourths majority is required by law.

Prospects for equity investment in the oil and gas sub-sectors

Apart from state ownership of the subsoil and subsoil resources, there are no legally protected monopolies in Azerbaijan's energy sector. In principle, the equity investor therefore has the following options available:

- a free, competitive market in which the investor can act as entrepreneur in developing a product without the need to negotiate specific terms with the government or competing State companies (e.g., in oil product retail supply, new refineries, and new gas transmission and distribution systems);
- sub-sectors open to licensing or franchising by the State (e.g., new deep-water oil and gas production);
- joint ventures with state companies (e.g., existing onshore and shallow offshore oil and gas production, existing refineries, oil transmission pipelines, and rehabilitation of the existing gas supply system);
- purchases of privatised assets in state enterprises in the current programme for restructuring and privatisation;

In practice, options are more circumscribed, in part by current practice and legislation and by the existence of de facto monopolies inherited from the Soviet period.

Some of the deterrents to private investors in particular sub-sectors include:

- *Oil and gas exploration and production:* the need for lengthy and uncertain negotiations for new fields, and price controls on output from existing fields;

- *Refining:* for new capacity – price controls, surplus refinery capacity in the Caspian region, 70% export tariffs; for existing capacity – export tariffs and price controls;
- *Oil product wholesale and retail:* difficulties in acquiring access to land, and price controls;
- *Gas transmission and distribution:* price controls and access to land for new systems.

Taxation

Corporate taxes in Azerbaijan consist of

- profit tax (35%; though 25% for joint ventures);
- payroll tax (35% for Social Insurance fund, plus 2% for Employment Fund); and
- withholding tax (15%) payable by stockholders on all dividend and interest income.

The income tax rate determined by a contract with the government cannot be raised during the term of the contract. If new or amending tax legislation is introduced after a contract has been concluded, such new taxes do not apply to the contracting parties. Taxes on the income of foreign legal entities can be waived or reduced if an equivalent exemption is provided in a foreign country to Azeri entities.

Income received by foreign partners from a joint venture is taxed at 15% when transferred abroad, unless otherwise provided for by an international tax agreement.

Production sharing arrangements (PSAs) provide for special tax regimes. In general, they stipulate that the government will receive 20 - 80% of oil revenues net of costs after financing charges and capital recovery. The rate also usually depends on the world oil price and transport costs.

In addition, the Azeri government derives revenue from the following petroleum specific taxes:

- Royalty: 15-25% of oil output.
- Petroleum products excise tax: 28 - 35% on domestic petrol sales.
- Road tax: 15% on domestic motor fuel sales.
- Strategic export tax: 70% of the difference between the domestic and contracted prices of oil products exported. (It appears that the export tax is not applicable to oil exports by the foreign partner in a joint venture; instead the taxes applied are as specified in the joint venture contract.)
- Bonuses: vary by project, although have accounted for a substantial portion of revenue during the past few years.

Local governments are entitled to raise some taxes and fees. They receive all individual income tax and a portion of the corporate profit tax and VAT.

ENVIRONMENT

Azerbaijan's oil refineries and chemical plants are major sources of air pollution in the Baku area, and heavy pollutors of Azerbaijan's coastal waters. Both onshore and offshore oil production add to pollution in the Caspian.

According to Socar, pollution standards agreed with some foreign consortia in the Caspian are less stringent than those that were applied, though not necessarily enforced, under Soviet-era legislation. Socar intends to pursue further negotiations to employ standards similar to those used in the North Sea. Socar's environmental protection department will then submit new standards to parliament to be signed into law.

Oil companies are concerned that imposition of new environmental standards should not set a precedent for changing contract terms, for example those regarding taxes. However, a number of contracts are for exploration only, with production terms, including environmental standards, yet to be determined. It would appear that existing Socar operations would not be subject to new, stricter regulations. It also appears to be the government's intention to get foreign investors to finance some of the clean-up of environmental damage caused by the Soviet oil industry.

The Caspian Sea has risen by about 2.5 m since 1978, and is expected to rise another 1.5 m by 2010. About 800 km^2 of land have been flooded in Azerbaijan so far, damaging some 20 wells at the Bibi-Eybat deposit. Another 460 km^2 are expected to be flooded by 2010. The area most affected is the coastal strip from the Apsheron peninsula south to the country's border with Iran.

OILFIELD EQUIPMENT AND SERVICES INDUSTRY

Azerbaijan was the major centre for oilfield equipment manufacturing in the Soviet Union. It produced some 65% of the USSR's well service, production and workover equipment, including most deep pumps and drill tubing. Only 6% of the Republic's equipment production was for Azerbaijan itself. However, many important inputs and components, especially for the offshore industry, were manufactured outside the Republic.

Because Azerbaijan has a relatively large and diversified industrial base, the oil field equipment industry, although large, accounted for only 4% of manufacturing output in 1992 and employed only 3% of the industrial workforce. Nevertheless, it is likely to be one of the country's most important manufacturing sectors in the future, due to the increasing demand for oilfield equipment in the Caspian region and in Russia, especially among foreign consortia. It also has potential for hard currency exports. Currently, over half of Azerbaijan's equipment sales are to Russian firms, with which there are reportedly payment problems.

In order to meet the needs of international oil companies operating both in Azerbaijan and other parts of the FSU, Azeri equipment manufacturers will have to conform to the quality standards used by the international petroleum industry.[23] They will also have to modernise manufacturing facilities and replace old production machinery and equipment. One of the most effective ways to accomplish this may be to form joint ventures with foreign partners that can provide investment capital and technology, as well as expertise in quality control, management and marketing. However, current legislation gives certain tax advantages to wholly foreign-owned firms, providing a disincentive to set up such joint ventures.

The Azeri oilfield equipment industry currently consists of some 14 plants and three design and engineering institutes under the holding company, Azneftechimmash.[24] The largest plant is Sattarhan, which produces oil gushers and deep-pump sucker rods. Schoeller Bleckmann (Austria) is to form a joint venture with the Sattarhan plant to manufacture high-grade steel sucker rods that comform to API standards. Some of the output is to be exported to Europe, the Middle East and Russia.

Kvaerner has established a joint stock company with several Socar associate firms and western partners to provide oil industry services, including the construction of pipelines and pump stations and the fabrication of piles. Many other oil service companies, notably from the UK, US, Netherlands and Japan, have already established a presence in Azerbaijan in hopes of obtaining contracts from the major E&P consortia operating in the Caspian.

Fabrication yards

Azerbaijan's fabrication yards are busy keeping up with the demand for upgraded offshore platforms and new rigs. Socar prefers foreign investors to upgrade Azeri infrastructure as much as possible. The major fabrication yard was run by Shelfprojectstroi (SPS), which was set up in 1978 with the assistance of the French company, EPTM. During the Soviet period, Shelfprojectstroi was the only producer of offshore jackets for work in water over 150 m. The SPS yards are now run by McShelf, a joint venture between Socar and McDermott (US) to construct deepwater platforms. Another Socar/McDermott joint venture, McDock, has already re-fitted several ships and crane barges needed to service the AIOC project.[25] AIOC plans to operate 12 vessels during the "early oil" phase of its project, while it is estimated that around 30 vessels will be needed in the South Caspian before 2000 for the servicing of the AIOC and other offshore projects coming onstream.

There are five semi-submersible mobile offshore drilling rigs in the Azeri section of the Caspian Sea. However, only the Dede Gorud, which underwent a US$40 million reconstruction in 1996, is capable of operating to international standards. Socar, which owns the Dede Gorud, has leased it for 10 years to its Caspian Drilling Corporation joint venture with Sante Fe Drilling. Socar requires at least part ownership of all drilling rigs operating in its sector.

23. Standards commonly used by the international oil industry are those of the American Petroleum Insitutue (API) and ISO 9000.
24. Azneftechimmash was created in 1993 with the addition of several equipment plants for the chemical and refining industries to the original holding company, Azneftemash, which was formerly dedicated to oilfield equipment.
25. The General Shiikhinskiy, refitted by McDock, was used to ferry sections of the Chirag-1 to SPS facilities. In March 1997 the AIOC took delivery of the crane ship, Azerbaijan, which it then leased from Socar. The Azerbaijan has a displacement of 12,000 tonnes and a maximum lifting capacity of 2,500 tonnes. It was upgraded by McDock at a cost of US$23 million.

The Dede Gorud is part of a rig-sharing arrangement called the "rig club". Made up of the major offshore consortia and players, including AIOC, Cipco, the Elf group, NAOC and BP/Statoil, the rig club was created as a way to co-ordinate the use of scarce infrastructural resources.

In 1997, the Shelf-5 semi-submersible underwent a US$115 million upgrade by the rig club, which is to charter it for 10 years. The Shelf-5 was refurbished at the Kaspmornefteflot shipyard by Kvaerner and local contractor Khazarmorneft. Approximately US$10 million of the cost will go to upgrading the shipyard. After its refurbishment, the rig will be able to drill in 475 m of water at depths of up to 6,000 metres. The goal is to have the Shelf-5 ready for drilling at the Shakh Deniz field by October 1998.

The Shelf-3 semi-submersible rig, whose technical specifications are similar to those of the Dede Gorud before its upgrade, is also to be refurbished. Most of the other semi-submersible rigs are either stacked or have been cannibalised for parts. Most of the six jack-up rigs are reportedly in equally poor or worse condition.

Table 8 Mobile offshore drilling rigs

Rig name (and old name)	Type	Status
Khazar-1 (60 years of October)	jack-up	stacked
Khazar-2 (26th CPSU Congress)	jack-up	stacked
Khazar-3 (28th of April)	jack-up	stacked
Khazar-4 (40 Years of Victory)	jack-up	at Umid 11
Khazar-5 (Kaspiy-1)	jack-up	idle after work in Iran sector
Khazar-6 (Kaspiy-2)	jack-up	leased to Caspian Drilling Co.
Dede Gorgud (Kaspmorneft)	semi-sub	spudded GCA-4 well for AIOC
Shelf-1	semi-sub	stacked (drilled Karabakh 2)
Shelf-2	semi-sub	stacked
Shelf-3	semi-sub	at Kapaz 8 (to be refurbished)
Shelf-5	semi-sub	being refurbished

Source: Petroconsultants.

The AIOC is leasing the Chirag-1 platform from Socar to work its first production wells from the Chirag field. The Chirag-1 has been refurbished and fit with various topside modules. The AIOC plans to drill 24 wells at the Chirag field through 1999.

Socar is reportedly constructing two additional jackets for the AIOC. These will also be fitted with modular topside components. The units, to be called Chirag-2 and Chirag-3, are scheduled to be completed by the end of 1999.

The AIOC employed the Israfil Huseinov barge to lay a 185-km pipeline from the Chirag-1 platform to shore. The Huseinov, which operates at a rate of 1.8 km of pipe per day, was originally built in Finland and shipped to Baku via the Volga-Don canal in 1987.

The Ispolin catamaran-type crane barge can carry over 1,200 tonnes and is designed for use in deep-water fields. It was built in two sections in Yugoslavia for Kaspmornefteflot (then under the USSR Ministry of the Oil and Gas Industry and now part of Socar). The parts were sent to the shipyard at Astrakhan, Russia, to be welded together, though after the break-up of USSR the barge was kept by Russia. Rosneft won ownership in a Russian arbitration court, though Socar still claims it. Socar and Rosneft have since agreed in principle on its lease to Socar.

Seismic services

As of the beginning of 1998, the only company equipped to perform seismic surveys offshore Azerbaijan was Caspian Geophysical, which is owned 51% by Socar and 49% by PetroAlliance (US). Caspian geophysical has its own data interpreting centre in Baku.

KAZAKSTAN

Kazakstan at a glance	
Land area	2.6 million km^2
Population	16.7 million
Capital	Akmola (moved in 1997 from Almaty)
President	Nursultan Nazerbayev (since December 1991; next election December 2000)
Currency	US$ 1 = 75 Tenge (October 1997)
GDP	US$ 21 billion (1996)
Real GDP growth	1.1% (1996)
Consumer price inflation	29% (1996)
Primary energy production	63 Mtoe (1996)
Energy consumption	50 Mtoe (1996)

SUMMARY

Overview of the energy sector: Kazakstan is a substantial producer of oil and gas, though coal still dominates both energy production and consumption. Primary energy production in 1996 in terms of tonnes of oil equivalent (toe) was approximately 59% coal, 32% oil, 8% gas and 1% hydro electricity. Major restructuring of the energy sector took place during 1997, including the formation of a national oil company.

Oil and gas reserves: Estimates of total oil reserves vary between 95 - 117 billion barrels, of which proven reserves are thought to be 8 - 22 billion barrels. Estimates of natural gas reserves are around 4 trillion cubic metres, of which 1.5 - 2.4 trillion are considered proven.

Oil production: Kazakstan is the second largest oil producer in the FSU. Production fell 20% between 1990 and 1994 as markets became complicated by the dissolution of the Soviet Union. Oil production has risen since 1994, reaching 22.8 Mt in 1996 and 25.7 Mt in 1997. Taking into account major projects such as Tengiz, output is expected to reach 40 - 45 Mt by 2000, and 75 - 100 Mt by 2010.

Oil and gas pipelines: Existing oil and gas pipeline systems were designed for the USSR as a whole. Regional pipeline systems in Kazakstan are therefore often more integrated with those of its neighbours than with pipelines in other parts of the country. This situation has traditionally resulted in a high degree of gross energy trade between Kazakstan and its neighbours.

Oil exports: Kazakstan currently sends most oil exports via Russia's Transneft pipeline system. Gross oil exports in 1997 were 16.8 Mt. However, Transneft limits Kazak net exports to under 10 Mt per year, citing capacity constraints caused by the export demands of Russia's own producers. Exports via rail, which are not subject to quotas, are small, but increasing. Limited amounts of oil are also sent across the Caspian to Azerbaijan by tanker, and to Iran in swap arrangements for Iranian oil in the Persian Gulf.

The most advanced major new oil export route is the Caspian Pipeline Consortium (CPC) project to build a dedicated pipeline to a new loading facility near the Russian Black Sea port of Novorossiysk. Construction of the CPC line is to begin in 1998, though may be delayed due to difficulties arranging rights of way agreements with several regional governments in Russia. The pipeline is scheduled to operational by the end of 2000, with an initial capacity of 28 Mt/year. Additional pipelines are being considered, including those via the Caspian Sea, Iran, Afghanistan and China. Oil available for export could reach 24 - 25 Mt by 2000, and 43 - 55 Mt by 2010.

Oil refining: Total nominal throughput capacity of Kazakstan's three major refineries is about 20 Mt, though in 1996 they were running at only 56% of capacity. Due to the legacy of the former Soviet pipeline system, much of Kazakstan's output is refined by Russian refineries in Samara and Ufa, while Kazakstan's Pavlodar refinery processes mainly Siberian crude. Kazak refineries produce high yields of heavy fuel oil and low yields of light products. Under the first wave of major privatisations in the energy sector in June 1996, part of the Shimkent refinery was sold to private investors. In early 1997, another investor won a tender for a three-year concession to run the Pavlodar refinery. Privatisation of the Atyrau refinery was halted during the energy sector re-organisation in early 1997, and the plant was given to the new national oil company, Kazakoil.

Natural gas: Natural gas production has been declining since 1990, and Kazakstan is a net gas importer. (Production was 6.09 Bcm in 1997, down from 6.16 Bcm in 1996.) Due to pipeline configurations, Kazakstan exports much of its own production to Russia, while importing most of the gas it actually uses from Turkmenistan and Uzbekistan. An expanded transmission network to eliminate the need for such imports is a priority. Kazakstan also handles the transit of Turkmen and Uzbek gas to Russia. In 1997, Belgium's Tractabel won a contract to run Kazakstan's natural gas transmission system.

Although Kazak reserves could handle increased production, potential Kazak gas exports to Europe would currently have to traverse Russia, which so far has refused to grant Kazakstan an export quota. Similar to the situation for oil, the Kazak government is looking for various routes to bring gas to the international market, including via Afghanistan to Pakistan and India; under the Caspian Sea to Azerbaijan and Europe; and through Turkmenistan to Iran and Turkey. Net gas imports are expected to decline slowly, and additional domestic production may be used mainly to meet additional domestic demand. By 2000, Kazak gas production is expected to rise to 8 - 10 Bcm, and 15 - 29 Bcm by 2010.

Foreign investment: Foreign direct investment in the oil and gas sector was reportedly US$ 627 million in 1997, bringing the total since 1991 to about US$ 2.5 billion. As of 1997 there were some 20 joint ventures working over 40 fields. Joint ventures accounted for over 25% of Kazak oil output in 1997.

New oil development focuses on the Tengizchevroil (TCO) joint venture, led by Chevron. Production from TCO is expected to exceed 180 kb/d in 1998. Assuming the CPC pipeline is built to schedule,TCO plans to substantially increase output to 500 kb/d by 1999, and to around 700 - 1,100 kb/d by 2010. The second major foreign investment project is Karachaganak, a gas-field development led by British Gas. Drilling offshore is to start in October 1998 by an international consortium following completion of seismic studies of the north Caspian in 1996 and the signing of a PSA with the government in November 1997. Other notable projects include the Uzen field, for which the China National Petroleum Company won the right to negotiate in August 1997.

Energy sector privatisation began in 1996 with sales of shares in several electric power stations, oil and gas production enterprises and refineries. In almost all cases, such sales were to foreign investors. Following the strong opposition by many oil industry managers, privatisation was sidelined during the government restructuring in 1997.

ECONOMIC BACKGROUND

Kazakstan is the largest former Soviet Republic in size after Russia, and fourth in population (16.7 million). Most of its 2.6 million km^2 are desert, and much of the country's thinly spread infrastructure, including oil and gas pipelines, is more integrated with that of surrounding countries than with that in other parts of Kazakstan.

In political terms, power is concentrated in the hands of the president. The current president, Nursultan Nazerbayev, also served as Communist party head for Kazakstan during the Soviet period. He was confirmed in his present post by 95% of the electorate in 1995. The next presidential election is scheduled for 2000.

Macro-economic policies during the first years of transition

As was the case in most other FSU countries, Kazakstans' first attempts at economic reform were effectively taken in response to Russia's unilateral price reforms in 1992. By the end of 1993, after Kazak output had declined precipitously for two years, inflation had spiralled out of control, and attempts to create an economic union with Russia and a number of other FSU states had not fulfilled expectations, the Kazak leadership turned to market style policies, looking at the dynamic Asian economies as a model. However, the government supplemented hard budgetary constraints and restrictive monetary policies with an attempt to solve the non-payment problem through state financing. Net debts which remained after netting out inter-industry arrears were financed by the budget and the central bank. This fuelled inflation in 1993 and 1994, and in the latter year led to a GDP decline of 25%, with only a small drop in inflation.

A one-year standby arrangement granted by the IMF expired at the end of 1994. In order to maintain IMF co-operation and to stem the decline in GDP, the government implemented a second stabilisation effort in 1995. This time hard budgetary constraints and monetary policy were reinforced by barring government financing of net positions in inter-enterprise debts and by withdrawing government guarantees for loans granted but not yet disbursed by domestic and foreign banks. A new Rehabilitation Bank was set up to address the problem of insolvent enterprises and their arrears. As a result of these policy efforts, the IMF renewed the standby agreement.

Annual inflation declined from 1,160% in December 1994, to 60% by December 1995. Both the current account deficit and budget deficit also improved considerably in 1995, and thereafter remained at relatively low levels (around 4.5% and 2.5% of GDP, respectively).

In mid-1996, the IMF approved an Extended Fund Facility (EFF) of US$446 million for three years. The decision was made in light of a comprehensive three-year reform programme submitted by the government, as well as the positive longer term prospects for production and exports of energy and non-ferrous metals. In 1996, Kazakstan experienced its first positive economic growth since 1989.

Price, trade and foreign exchange liberalisation

Remaining price and profit margin controls were abolished in 1994. However, the monopolistic structure of the economy effectively excluded price competition and offered little resistance against inflationary pressures that built up as a result of the lack of fiscal and monetary discipline during the first years of transition.

Trade and foreign exchange regulation were gradually reduced after 1994. All export quotas were abolished in 1995 and barter trade prohibited. From August 1995, the government no longer required exporters to sell their foreign exchange earnings on the Kazak Interbank Currency Exchange (KICEX).

After the Tenge was introduced as the new national currency in 1993, the National Bank of Kazakstan (NBK) allowed the Tenge's value to be determined on the KICEX, where official market intervention has reportedly been minimal. As in other countries in transition, the national currency's nominal value has not declined in full concert with inflation. From the first quarter of 1995 to the first quarter of 1997 it declined by only 20% vis à vis the US dollar, while the consumer price index rose by 29% in 1996 alone.

Privatisation

According to EBRD estimates, enterprises that were majority-owned by private investors produced around 40% of Kazakstan's GDP in 1996. Small-scale privatisation is close to completion, with over 13,000 enterprises now in private hands. Among the 4, 000 enterprises that employ between 200 and 5,000 workers, half have been privatised through coupon auctions. Privatisation Investment Coupons distributed to the public may be used to purchase shares in some 170 Investment Privatisation Funds, which in turn bid for shares of enterprises offered at auctions.

For the third phase of privatisation, 180 large enterprises (each with over 5,000 employees) were identified for privatisation on a case-by-case basis. Among those offered were coal, electricity, and oil and gas production enterprises. Only this third phase has actually generated revenue for the state budget.

Non-payment

In December 1996, non-payments stood at 770 billion tenge, or 50% of GDP. Another 30 billion tenge were owed in wage arrears. Moreover, according to government estimates, 70% of all state-owned enterprises were losing money. Among the large enterprises put under the control of the Rehabilitation Bank, which was set up in 1994 to prepare state enterprises for privatisation, seven were liquidated by the end of 1996. These liquidations may have helped slow the growth of the non-payments problem. The law on bankruptcy was tightened somewhat in January 1997.

The financial sector

The banking sector has been dominated by four large, state-owned banks. Out of some 160 commercial (mostly small) banks, over 50 have become casualties of the country's ongoing banking crisis. On the other hand, the National Bank of Kazakstan (NBK) appears to have become increasingly independent of the government and more efficient in its role as supervisor of the commercial banking sector.

The Almaty Stock Exchange opened in 1997, although by the beginning of 1998, turnover was still very limited. While awaiting speedier privatisation of the oil sector, foreign investment funds have turned their interest to shares in banks, such as Kazkomertsbank (which is also traded on the Berlin stock exchange). The opportunity to issue shares on the stock exchange could become an incentive for local companies to adopt more transparent accounting and reporting practices.

The tax system

In 1995, a new tax code reduced the number of taxes from 49 to 11, and consolidated 45 separate tax laws. Many previous exemptions were eliminated, and more efficient procedures for registration, assessment, collection and audits were established.

In early 1997, the government compiled a "black list" of the 35 largest corporate tax debtors which together owed the government US$13 million, and threatened them with seizure of assets. (An overview of taxes faced by investors in the oil and gas sector is given in the Investment section of this chapter.)

IFI loans

In mid-1997, the IMF approved a US$430 million loan from the Extended Fund Facility to the government of Kazakstan, though nothing had been disbursed as of early 1998. As of mid-1997, the EBRD had approved loan projects totalling US$189 million, though none of these were for the energy sector; and the World Bank had committed about US$460 million, of which US$109 was for the rehabilitation of the Uzen oil field (approved in July 1996).

Technical assistance

All technical assistance activities are co-ordinated by the Committee for Utilisation of Foreign Capital (CUFC), which acts as an autonomous body, though receives policy guidance from the Agency for Strategic Planning and Reforms, and the Ministry of Energy, Industry and Trade. Most technical assistance activities center around capacity building in the financial sector and in public administration.

Table 1 Technical assistance (as of mid-1996)

Agency	All TA (US$ million)	Energy sector TA (US$ million)
USAID	172	8.9
UK	12.5	2.5
Germany	18	
UN	5.1	
World Bank	5.6	
EU	79	10[1]
EBRD	33	1[2]
ADB	6.2	0.6
Total	331	22

(1) New electricity tariffs for Kazakenergo, refurbishment of Ermokovsk power station, policy advice, establishment of an energy centre which has closed down in the mean time.

(2) One project was the preparation of the Ekibastuz Power Station rehabilitation and the other a least cost development study for the national power system.

New national capital

Kazakstan is in the process of transferring its capital to Akmola, which is 1,500 km to the north of Almaty, the old capital (formerly called Alma Ata). The relocation of some government departments began in 1996, and the official transfer took place in November 1997. The primary official reason for the move was the vulnerability of the old capital to earthquakes, and the physical limits to growth imposed by the surrounding mountains. Another important consideration appears to be the need to politically integrate the country's large population of ethnic Russians, most of which lives in the north.

Although removed from other major cities in central Asia, Akmola is located at the crossroads of two of the country's largest railway lines, the South-Siberian and the Petropavlovsk-Karaganada-Chu. It is also served by the Yekaterinburg-Almaty highway. The new capital is somewhat closer than Almaty to the main oil and gas production centres in the Northwest.

Akmola currently suffers from lack of infrastructure, such as office space and telecommunications. For many foreign companies already established in Almaty, moving to the new capital or opening a branch office there could represent a significant expense of doing business. Foreign businesses are often urged to donate to the New Capital Foundation, a non-profit entity formed to help fund Akmola's development. As of the beginning of 1998, most foreign companies and embassies continued to operate from the old capital.

Akmola was declared a free economic zone in January 1997, and construction companies operating there are exempted from certain taxes for five years.

OVERVIEW OF THE ENERGY SECTOR

Over the period 1990 - 1995, energy production declined 30%, compared to a 37% drop in GDP. Energy's share in GDP is now over 10%, and represents one-fourth of industrial value added. Energy's share of GDP is expected to grow further, as is its share in total fixed capital investment. Between 1993 and 1995, the share of energy in capital investment appears to have remained at around 20%.[1]

Although Kazakstan is a substantial producer of oil and gas, coal has dominated both energy production and consumption. In 1996, total energy production was about 63 million tonnes of oil equivalent (Mtoe), down from 89.3 Mtoe in 1990. Primary energy production in 1996 was approximately 59% coal, 32% oil, 8% gas and 1% hydro electricity.

Total domestic energy consumption in 1996 was about 50 Mtoe, down from approximately 74 Mtoe in 1991. Some 60% was in the form of coal, 18% in oil, and 19% in gas.

The large role of coal in domestic energy consumption is one reason Kazakstan can afford to export a large portion of the oil it produces. Net energy exports in 1996 amounted to some 13 Mtoe, down from 17 Mtoe in 1991. Gross energy exports in 1996 were approximately 24 Mtoe, compared to 52 Mtoe in 1991. Gross energy exports in 1996 were 24% coal, 67% oil, and 9% gas. The main reason for the large difference between gross and net exports is the high degree of trade in oil and gas between Kazakstan and its neighbours. This is due in large part to pipeline configurations – originally designed for the USSR as a whole – that often link production centres in one country with consumption centres in another.

Kazakstan must currently send all pipeline exports of oil and gas via Russia. A new dedicated oil export pipeline is expected to be in place by the end of 1999 (see below). Although it will cross Russia, it will not be under the control of Transneft, the Russian pipeline authority.

Coal

Kazak coal production was around 85 Mt in 1996, or about 51% of total energy production in terms of toe. Most of Kazakstan's coal is produced in the large Karaganda basin and is extremely high in ash content. Some 70% is from underground mines and the rest from open cast mines. Most coal is used in power generation. Kazakstan is a net exporter of coal, although production has declined in recent years due in part to shrinking markets in other FSU republics. Although the coal is inexpensive to produce, there are questions regarding the profitability of exports due to the long distances involved. Labour unrest related to the non-payment of wages has been a continuing problem in the Kazak coal sector.

1. State capital investment increased from 26% to 36%. However, the state's share in total capital investments declined during this period from 76% to 57%.

Electricity

Electricity generating capacity in Kazakstan is around 18.5 GW, some 16.7 GW of which is thermal, with most of the rest hydro.[2] Most thermal powered generating capacity is coal-fired and situated near coal mines. In 1996, only 13% of electricity was produced from gas and fuel oil (mostly the former), and 7% from the country's four hydro-electric dams

The use of gas in power generation is expected to increase, though the extent is uncertain. Large amounts of gas could be produced from a number of fields currently being explored or developed, including Karachaganak and the Kazak sector of the Caspian Sea. Difficulties in exporting gas help make power generation an attractive option. However, many potential consumption areas are located near large coal deposits which may be cheaper to exploit.

Electricity generation in 1996 was 59.31 TWh, down from 66.98 TWh in 1995, and 86.13 TWh in 1991. Kazakstan is a net importer of electricity (6.85 TWh in 1996), mainly from Russia and Turkmenistan. In 1996, around 10% of total import expenditure was on Russian electricity. As of mid-1997, Kazakstan reportedly owed the Russian power industry some US$400 million in payment arrears.

Similar to the situation in other energy subsectors, the electricity grid serving Kazakstan was designed with little concern for administrative boundaries between what were then republics of the USSR. The northern regions of Kazakstan were included in the grid for the European part of Russia, while the southern regions were part of the Central Asian grid. The Kazak systems are interconnected with those of Russia, Uzbekistan, Turkmenistan, Kyrgyzstan and Tajikistan. Many parts of northern Kazakstan continue to be dependent upon Russia for power. Two high voltage transmission lines are being considered to link Kazakstan's northern and southern grids at an estimated cost of US$480 million.

Table 2 Electricity consumption, production and imports (TWh)

	1990	1991	1992	1993	1994	1995	1996	1997 (est)
Consumption	104.72	101.62	96.87	89.15	79.43	74.38	66.16	56
Production	87.38	86.13	82.86	77.44	66.40	66.98	59.31	52
Total imports	17.34	15.49	14.01	11.71	13.03	7.40	6.85	4
from Russia	7.59	7.17	8.06	6.11	7.18	4.20	3.64	2.4
from Uzbekistan	2.93	2.70	0.17	0.94	0.53	0.43	0.01	0.0
from Turkmenistan	4.90	4.28	3.97	3.19	2.13	1.75	1.19	0.8
from Kyrgyzstan	1.62	1.10	1.73	1.02	2.51	0.78	1.64	0.8
from Tajikistan	0.30	0.25	0.08	0.45	0.68	0.24	0.37	0.0

Source: Kazakenergo

In 1996, the government decided to privatise up to 80% of the country's power stations, in part to raise money to pay off debts for electricity imports from Russia. As of mid-1997, the government had privatised approximately 50% of the country's generating capacity. For

2. The country's one nuclear power plant, a 350 MW fast-neutron breeder reactor at Aktau, accounts for only some 0.7% of electricity production and is used primarily to run a desalination plant on the Caspian Sea coast. However, the government is considering plans to build several large nuclear power stations with a total capacity of 4,000 - 6,000 MW over the next four to six years, including a 3 x 640 -MW nuclear plant on the banks of Lake Balkhash. Construction of the US$ 2 billion Balkhash plant is scheduled to begin in 1999. Kazakstan has a uranium ore processing plant at Stepnogorsk.

example, Tractabel (Belgium) bought the heating and power company serving Almaty, and Japan Chrome (British-registered) purchased 53% of the 2,400-MW coal-fired Yermak power station in Pavlodar province. The results of a 1997 tender to run the national power grid, Kazenergo, were cancelled, however, and the government now intends to retain control. According to the State Committee on Investments, US$500 - 600 million in investments will be required annually in the power sector over the next few years.

Wholesale electricity prices are determined by the market, transit prices by the State Committee for Price and Antimonopoly Policy,[3] and end-use prices by local government committees. As in other countries in the region, non-payment is a large problem.

ORGANISATION OF THE OIL AND GAS SECTOR

The organisation of the Kazak oil and gas sector has undergone numerous changes since the dissolution of the Soviet Union. Recent major restructuring took place in March 1997, and again in October 1997. Under the March 1997 re-organisation, the Ministry of Oil and Gas, Ministry of Coal and Power, and Ministry of Geology were replaced by a Ministry of Energy and Natural Resources, which itself was later absorbed into the new **Ministry of Energy, Industry and Trade** under a Presidential decree of 10 October 1997. The new ministry also took over many of the functions of the former Ministry of Economics, including the right to quarterly approve the oil export plans of all Kazak producers.

Under the March 1997 re-organisation, Munaigaz, the state-owned holding company for Kazakstan's oil and gas enterprises, was disbanded. Most shares in its subsidiaries were transferred to the new state oil company, **Kazakoil**.[4]

The role of Kazakoil is still developing, although its influence on policy matters appears to be increasing, especially since its former head became Prime Minister in October 1997.[5] According to a government resolution issued in March 1997, Kazakoil's main functions include the following:

- own, use and manage the government's stakes in joint-stock companies in the oil and gas sector, including its shares in the Caspian Pipeline Consortium (CPC);
- assume responsibility for the Kazakstan Promissory Note (a secondary debt instrument issued by the pipeline consortium, CPC-Kazakstan);
- exercise the government's rights under production sharing agreements, royalties and other exploration, production and refining deals, including those with foreign investors;[6]

3. Until October 1997 this Committee was under the Ministry of Economy. It was then transferred to the newly created Ministry of Energy, Industry and Trade.
4. The disbanded Munaigaz had itself been formed in 1993 from the previous national oil company, Kazakmunaigaz. Munaigaz had 34 subsidiary companies, including oil and gas production units and related enterprises such as pipeline and geophysical outfits.
5. The former Minister of Oil and Gas, Nurlan Balgimbayev, was named President of Kazakoil in March 1997. He subsequently became Prime Minister in October 1997.
6. However, according to a tax ruling of 1997, Kazakoil does not have the right to set or collect royalties from joint ventures or companies owned and controlled by foreign investors. Royalties are paid directly to the State Budget of the Ministry of Finance only.

- serve as operator for hydrocarbons exploration, production, refining and transport projects in Kazakstan;
- help organise tenders for exploration and production;
- participate in the marketing and sale of hydrocarbons;
- manage output received as royalties and compensate the state budget accordingly;
- represent Kazakstan under the 1994 and 1996 loan agreements with the World Bank;
- help draft a programme to restructure and privatise the oil and gas industry.

In early 1998, the government announced that it intended to find a "strategic partner" for Kazakoil, presumably one of the major western oil companies active in Kazakstan.

A list of companies under the control of Kazakoil is given in Table 3. A list of joint ventures between Kazakoil and foreign firms may be found in Table 16.

Table 3 Shares (%) owned by Kazakoil in various companies, as of October 1997 (Remaining shares are owned by employees and/or private investors)

Production associations	**%**
Mangistaumunaigaz	30
Tengizmunaigaz	85
Embamunaigaz	85
Uzenmunaigaz	90
Kazakstankaspiishelf	90
Karachaganakgazprom	90
Other	
Atyrau refinery	53.2
Mangistaumunaigeofizika	95.31
Embaneftgeofizika	39
Munaigeofizika	20
Kyzlordapromgeofizika	90
Mangistaupromgeofizika	90
Ozenpromgeofizika	90
Mangistauelektro-montazhavtomatika	39
Geoiglikservis	(golden share)
Astana-Kurlys	100
CPC (Govt. share)	19
CPC (with Amoco)	1.75

Source: Government Order N. 410 of 24 March 1997 and updates provided by Kazakoil.

The former Munaigaz's two pipeline associations, Yuzhnefteprovod, and the Kazak & Central Asian Trunk Pipeline Association (MN KiSA), were brought together in early 1997 to form the nucleus of a new state-owned company for pipeline transport, **Kaztransoil**. The Central Dispatch function of Munaigaz was also turned into a separate state-owned entity, the **Main Oil and Gas Dispatch Department**. In July 1997 the gas transit functions of Kazakgaz were given on a concession basis to private company **Intergaz Central Asia**, which is owned by Tractabel (Belgium).

A number of oil and gas production associations and refineries were privatised in 1996 and 1997, though privatisation in the oil and gas sector was virtually halted in early 1997. Privatisation was originally the prerogative of the State Committee for the Administration of State Property and the Interdepartmental Commission for the Privatisation of the Oil and Gas Sectors, however, both these bodies were abolished in early 1997 and their functions taken over by the departments of Property Management and Privatisation of the **Ministry of Finance**. (For more on privatisation, see the Investment section.)

The **State Committee on Investment** has taken over the State's share in most Kazak companies, excluding those transferred to Kazakoil. It is also to be the primary state body dealing with investment policy and with foreign investors, including in the oil and gas sector. (See the Investment section.)

Long-term economic policy guidance is provided by the **Agency for Strategic Planning and Reforms**. The Agency was established in April 1997 by the President and reports directly to him. In October 1997, President Nazerbayev presented the long-term strategic plan prepared by the Agency, entitled, "Programme for the Social and Economic Development of Kazakstan until 2030". The programme outlines long-term development goals and investment priorities. According to this programme, the oil and gas sector is expected to be one of the major engines for the future growth of the economy. The Agency for Strategic Planning and Reforms is obliged to review the plans of other government bodies to ensure their consistency with its own programme.

OIL RESERVES AND PRODUCTION

Estimates of Kazakstan's total oil reserves vary between 95 and 117 billion barrels, with proven reserves between 8 and 22 billion barrels. For example, a US government report issued in early 1997 estimates proven and probable reserves at 95 billion barrels, of which it considers 10 billion to be proven.[7]

Table 4 Reserves of principal Kazakoil production associations

Production association	Oil and condensate (Mt)	Associated gas (Bcm)	Natural gas (Bcm)
Mangistaumunaigaz	205.7	12.9	39.8
Tengizmunaigaz	28.6	3.9	23.5
Uzenmunaigaz	220.6	6.9	35.3
Embamunaigaz	70.2	1.7	1.9

Source: Kazakoil

7. Report to Congress on Caspian Region Energy Development, 1997.

Most of Kazakstan's oil and gas reserves are found in and around the Caspian Sea, in the Mangystau and Atyrau regions. Potential oil and gas fields cover an area of approximately 1.7 million km^2, only about half of which has been geologically explored.

Kazakstan is the second largest oil producer in the former Soviet Union after Russia. Kazak oil output stood at 21.9 Mt in 1992, but fell to 18.5 Mt in 1994 as markets for exports became complicated by the breakup of the Soviet Union. Oil production rose to 22.8 Mt in 1996, and to 25.7 Mt in 1997, at which time joint ventures supplied about 25% of the total. Kazakstan hopes to produce 30 Mt in 1998.

Table 5 Oil output of principal Kazakoil production associations (Mt)

Year	Mangistau-munaigaz	Tengiz-munaigaz	Uzen-munaigaz	Emba-munaigaz
1990	7.45	1.04	7.32	1.47
1991	7.01	1.01	6.01	1.50
1992	6.43	0.82	5.07	1.59
1993	6.05	0.82	5.07	1.59
1994	5.32	0.89	3.33	1.64
1995	4.60	0.87	2.95	1.73
1996	4.51	0.90	2.83	1.74

Source: Kazakoil.

According to the "high" and "low" case scenarios of the IEA, Kazak oil production is projected to be between 40 - 45 Mt in 2000, and 75 - 100 Mt in 2010.

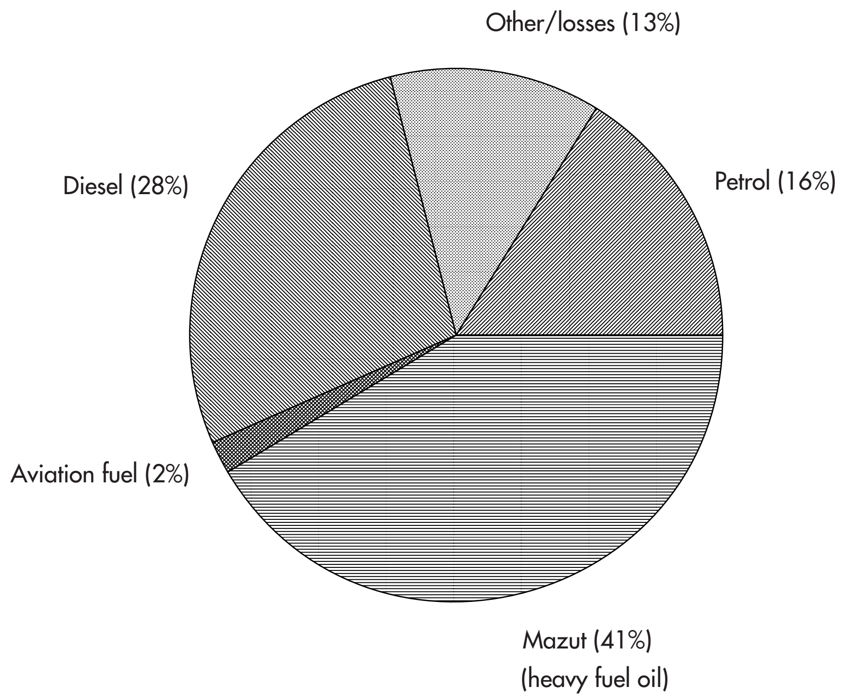
OIL REFINING

Due to the legacy of the Soviet pipeline system, much of Kazakstan's output is exported to Russian refineries in Samara and Ufa, while Kazakstan's Pavlodar refinery receives most of its crude from western Siberia.

In 1996, total nominal throughput capacity at Kazakstan's three refineries, Pavlodar, Shimkent and Atyrau, was about 20 Mt (380 kb/d). Actual throughput in 1996 was 11.1 Mt. Some 6.82 Mt of this came from Kazak producers, the rest from Russia. Despite a 2.5% increase in throughput over 1995, Kazak refineries in 1996 worked at only 58% of capacity, including Pavlodar at 40%, Shimkent at around 60%, and Atyrau at 82%. In 1997, Kazak refineries processed an estimated 8.6 Mt of Kazak crude.

Kazak refinery output is characterised by high annual average yields of heavy fuel oil and low yields of high-value light products. This results in large imports of the latter, especially diesel, and exports of the former.

Figure 1 Kazak refinery output (1Q97)



Source: Interfax and IEA estimates

Some 90% of the Shimkent refinery was sold to private investors in early 1997. The Pavlodar refinery was handed over to foreign investors at around the same time under a three-year concession. A tender for Atyrau was cancelled in March 1997 and ownership transferred to Kazakoil.

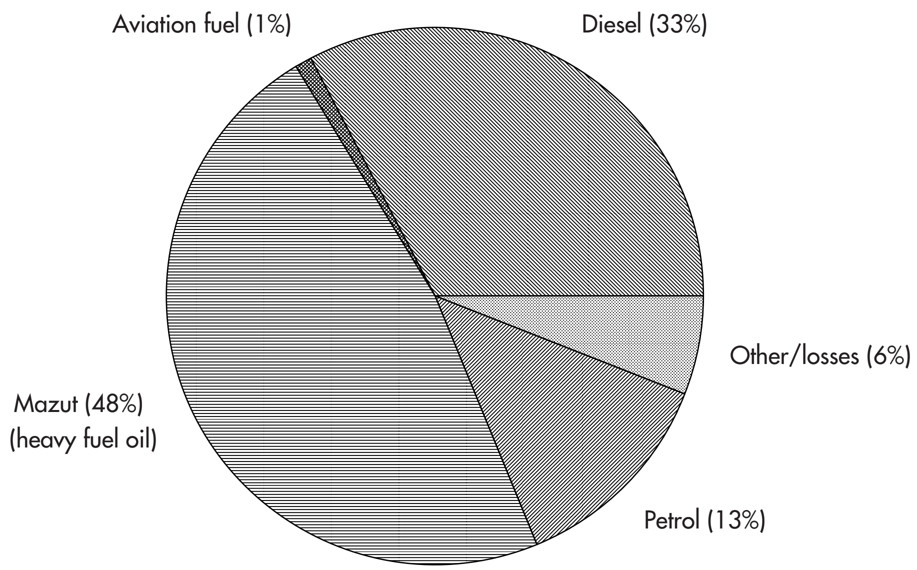
Atyrau

The Atyrau (formerly Guryev) refinery is located near the Caspian Sea coast. Nominal capacity is about 5.5 Mt/year (110 kb/d). Throughput in 1995 was 4.3 Mt (86 kb/d). The average composition of refinery output between 1991 and 1994 is shown in Figure 2.

Atyrau arguably enjoys the most reliable crude supply of Kazakstan's three refineries, since it receives its crude exclusively from domestic sources. It is located near the country's main oil fields, with pipeline connections to the Mangishlak, Martyshi and Tengiz fields. However, it is arguably Kazakstan's most obsolete refinery. Atyrau was established in 1945 with equipment provided under the US Lend-Lease programme and was originally intended for refining oil from Baku. It was expanded several times, though currently requires extensive refurbishment. In 1996, a French company drew up reconstruction plans to raise refining depth to 91% at an estimated cost of US$1 billion over five years, which was to be recouped after a further seven years of operation. However, as of the end of 1997, no major refurbishment had been implemented.

About 17% of the Atyrau refinery is in the hands of private investors. Of this, some 12% is owned by Telf AG, a Swiss-registered firm. Most of the other shareholders have transferred their shares to

Figure 2 Atyrau refinery output 1991-1994



Source: World Bank

Telf to manage in trust in connection with a loan by the latter to partially modernise the plant. An additional 30% is owned by the refinery's employees. The remaining 53.1% was offered for tender in early 1997 in a package with two local combined heat and power plants. The tender was won by Essex Refinery Corporation, a British Virgin Islands-registered company. However, the tender results were cancelled in April 1997 after the Kazak authorities expressed doubts regarding the ability of Essex to meet its US$1 billion investment pledges. The controlling shares were subsequently handed over to Kazakoil. KPMG Zhanat is to perform an audit of the refinery to find out the value of Atyrau's shares ahead of their possible placement on the Kazak stock market.[8]

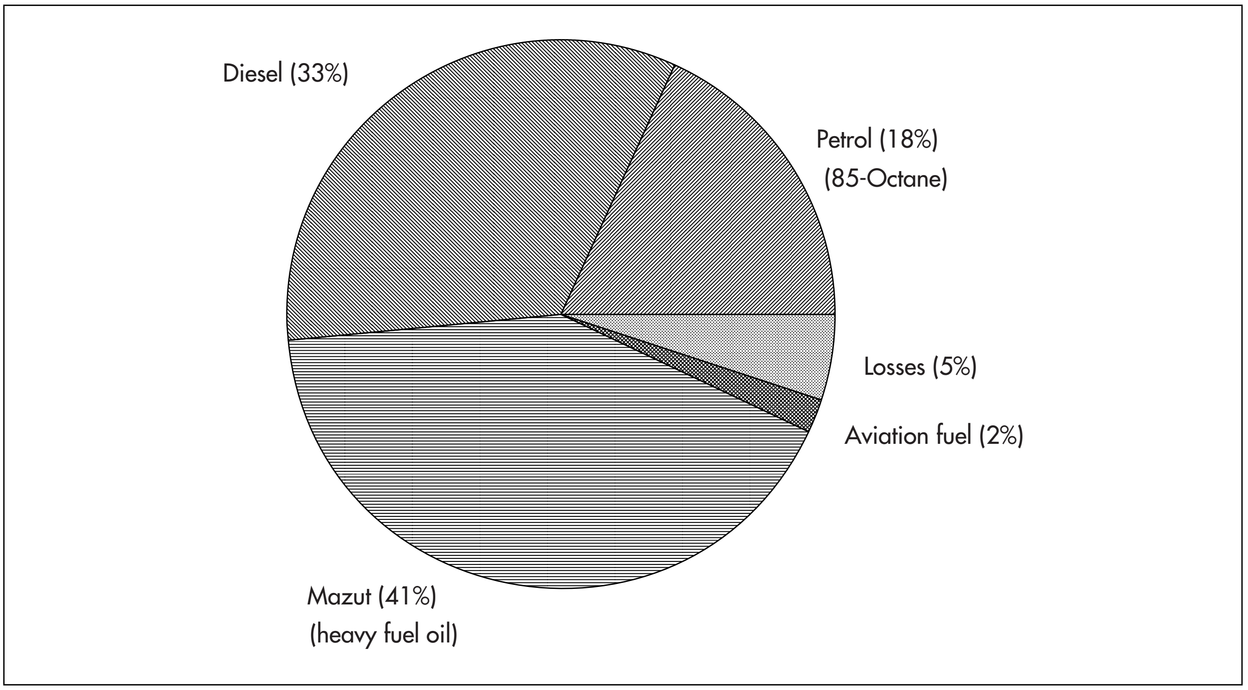
Atyrau is involved in the 36-kb/d Gyural oil producing joint venture with Kazak partner Akhbota and Urals Trading at the Baklaniy field, north of Atyrau.

Shimkent

The Shimkent refinery has a nominal capacity of 7.5 Mt per year (150 kb/d). In 1995, it processed 3.7 Mt (74 kb/d) of mainly Russian crude. Russian suppliers halted shipments to Skimkent (and Pavlodar) mainly due to non-payment. In 1996, 1997 and through early 1998, Skimkent processed only kazak oil, the bulk of which was supplied from the Kumkol oil fields, Shimkent's main crude source for most of the past 20 years. Some minor quantities of crude were purchased in 1996 and 1997 from Aktobemunai (Aktyubinskneftegaz) and shipped by rail, and some condensate from Uzbekistan. The condensate agreement with Uzbekistan was not renewed for 1998.

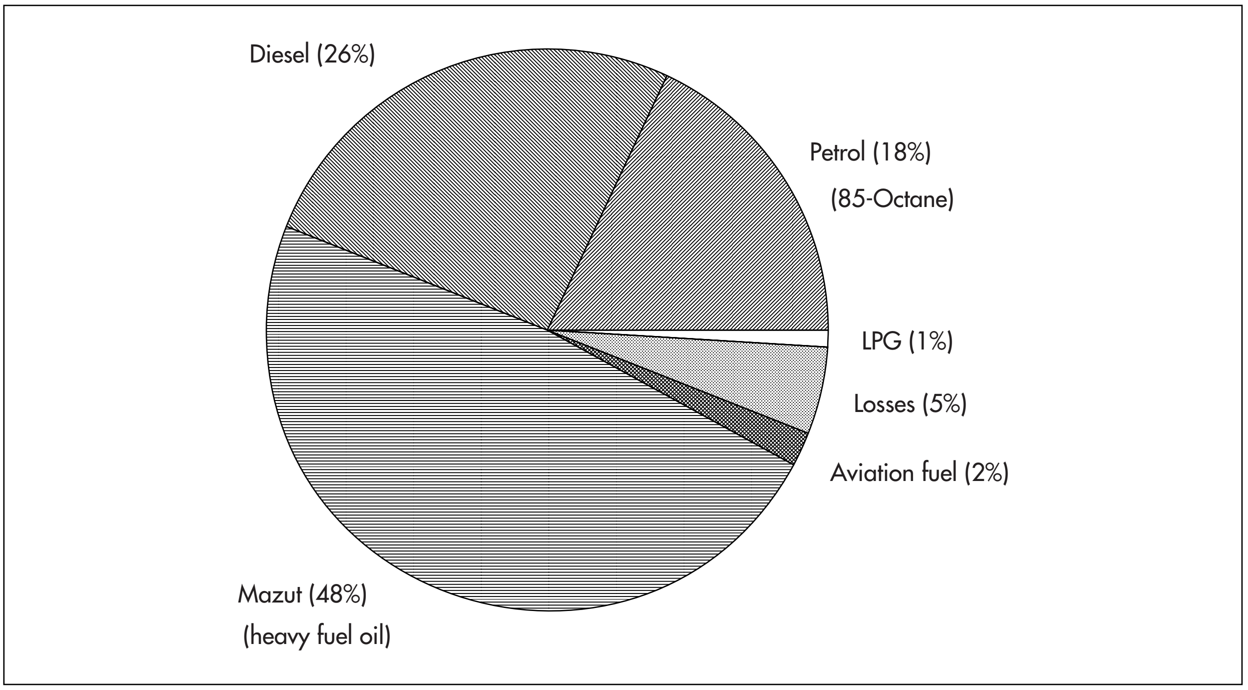
8. Management reportedly told its shareholders that in 1996 Atyrau made a net profit of 3 billion tenge (US$39.8 million) from sales of 20 billion tenge (US$265 million), and spent 1.7 billion tenge (US$22.5 million) from an "accumulation fund" on capital expenditures. (Interfax 2/5/97).

Figure 3 Shimkent refinery output: Summer (April-September 1997)



Source: Hurricane Hydrocarbons

Figure 4 Shimkent refinery output: Winter (October 1996-March 1997)



Source: Hurricane Hydrocarbons

In October 1997 Shimkent processed around 75 kb/d. Skimkent's new owners, Kazvit (see below), have developed a three-phase investment plan to raise processing depth from 55% to 80% within five years. They also plan new facilities for atmospheric and vacuum distillation, reforming, catalytic cracking and mild hydrocracking.

In June 1996, 85% of Shimkent was awarded to foreign trading company Vitol for US$60 million, with promises by Vitol to invest a further US$150 million. However, actual ownership of the shares passed to an entity called Kazvit Holdings, formed by Vitol, but reportedly largely controlled by locally-owned Kazkomerzbank. Kazvit is buying the shares from the state in three installments of US$20 million each. As of the beginning of 1998, Kazvit controlled around 60% of the plant. Vitol and the new owners have been under investigation by Kazak tax authorities for alleged concealment of income.

Most of Shimkent's crude comes from the domestic Kumkol field, which is connected to the refinery by pipeline. Hurricane Hydrocarbons, which owns Kumkol, sells crude to third parties before processing, or pays for the processing and markets the products itself.[9]

Almaty, 650 km away, provides a solvent market for Shimkent products such as jet fuel, petrol and diesel. (Car ownership in Almaty has more than doubled since 1992.) Shimkent also sells its products in the Southern, Zhambyl, and Kzyl-Orda oblasts and to Bishkek, the capital of Kyrgyzstan. A product pipeline connects Shimkent to Tashkent, Uzbekistan, though currently is not being used. The main competition for Shimkent is likely to come from the new refinery in Bukhara, Uzbekistan, whose initial capacity of 51 kb/d should be operational in 1998.

Pavlodar

Commissioned in 1978, Pavlodar is one of the most modern refineries in the former Soviet Union. With a nominal capacity of 7.5 Mt per year (150 kb/d), it has a designed product yield of 83% and fluidised catalytic cracking facilities. However, Pavlodar is wholly dependent upon crude imported from Russia (received mainly under swap arrangements). Furthermore, it is designed to run on low-sulphur oil of the type typically produced in Western Siberia. (Most domestic crude has a high sulphur content.) Pavlodar has historically provided 60% of Kazakstan's petrol, 50% of its kerosene, and 40% of its diesel. Pavlodar's throughput in 1995 was 3 Mt, though it processed only 2.5 Mt (50 kb/d) in 1996.

In early 1997 Crispin Company Ltd (CCL) of the UK won a tender for a three-year concession, extendable to five years. After three years of lease, the refinery may be privatised, with CCL given the right of first refusal of shares. CCL is apparently under no obligation to pay the refinery's debts and may pass all claims directly to the government.

CCL plans to double refinery throughput, although Pavlodar has apparently been hit hard by inflows of cheaper petrol and gas oil imports from Russia.

9. In February 1997 Kumkol crude was selling for US$70/tonne at the Shimkent refinery . In October 1997 it was selling for US$87/tonne.

New refineries

There are plans for several new refineries, including the following:

- Construction of a new US$1.5 billion refinery in Mangistau has been proposed by the Japanese companies Mitsui, Mitsubishi and Toyo Engineering.
- An agreement of March 1997 between Kazakoil and Amoco (US) includes provisions for constructing a number of small refineries;
- In 1995, Japan's Sumitomo Corp. and Canada's SNC-Lavalin Group won a US$480 million contract to build a large oil export refinery in the Zhanazhol oil field near Aktyubinsk.

Given the excess oil processing capacity in Kazakstan, new refineries may experience difficulties finding markets. Existing refineries are likely to report a drop in profitability due to the introduction of excise taxes on oil, petrol and diesel. Since domestic customers already are experiencing serious payment difficulties, it may be difficult for refineries to pass on cost increases to customers.

Oil product consumption

In 1996 domestic consumption of oil products stood at some 9.4 Mt, down from 20.7 Mt in 1990. According to Kazak government estimates, domestic consumption is expected to reach 1990 levels again by 2012. This is consistent with the two long term scenarios of the IEA.

Product distribution has been privatised and prices liberalised. The retail product market is perceived as reasonably open and competitive. Retail prices including taxes are comparable to those in the US. Foreign participation in petrol retailing includes Mobil (US), Chevron (US) and Lukoil (Russia), each of which owns several service stations. Car ownership, currently at 57 cars per 1,000 inhabitants, is low by international standards, but the highest in Central Asia.

OIL TRANSPORTATION AND TRADE

In 1997 Kazakstan's two pipeline associations, Yuzhnefteprovod, based in the Caspian port of Aktau, and the Kazak & Central Asian Trunk Pipeline Association (MN KiSA), based in Pavlodar, were brought together under a new state-owned, closed joint stock company, Kaztransoil.[10] The Central Dispatch function of the former Munaigaz was turned into a separate state-owned entity called the Main Oil and Gas Dispatch Department.

As mentioned in the discussion of refining, many Kazak production areas are not connected to refining and consumption centres within the country, but to those in neighbouring countries, and vice versa. Much of Kazakstan's oil is exported to Russian refineries in Samara

10. MN KiSA operates the pipeline linking western Siberia to the Pavlodar and Shimkent refineries, while Yuzhnefteprovod operates the system linking Atyrau to Russia's Samara refinery.

and Ufa in government-to-government swaps for Siberian crude that is refined in Kazakstan's Pavlodar refinery.

Kaztransoil controls around 6 300 km of pipeline for crude oil and 1,100 km for oil products. It has over 3 million cubic metres of oil storage capacity, 32 pumping stations, 18 collection points, four railroad loading stations and two oil loading piers for Caspian vessels.

A number of factors have contributed to reduced use of oil pipeline capacity in recent years, including:

- falling output at fields in western Kazakstan as reserves decrease;
- quotas imposed by the Russian pipeline company Transneft on oil exported via Russia;
- falling supplies from Russia to Kazakstan's Pavlodar refinery;
- falling imports by other Central Asian countries of Russian crude via the Omsk-Pavlodar-Shimkent line to Chardzhou, leaving this line almost completely idle.

Table 6 Selected oil pipeline capacity and use in 1995 and 1996 (Mt/year)

Pipeline	Design capacity	Actual use (Mt) 1995	Actual use (Mt) 1996
Uzen - Atyrau	25	8.5	10.9
Tengiz - Atyrau	15	2.5	4.4
Atyrau - Samara (export)	13	8.2	10.3
Kenkiyak - Bestamak	6.5	2.6	2.6
Bestamak - Orsk (export)	6.5	1.9	2.1
Omsk - Pavlodar (import)	24	3.6	3.1
Kumkol - Karakoiyn - Shimkent	22	3.0	2.7

Source: Interfax and others

Table 7 Pipeline deliveries of oil originating in Kazakstan in 1996

To Kazak refineries	4.9 Mt
Exports to Russia under govt. swaps	3.4 Mt
Other govt. exports	3.0 Mt
Exports by JVs	5.0 Mt
Export to Russian refineries (taken back as products)	3.9 Mt

Source: Interfax, Kaztransoil and IEA estimates

Planned internal oil pipelines

A major internal oil pipeline in the planning stages would connect the Kenkiyak, Zhanazhol and Kumkol oil fields in the west with the Pavlodar and Shimkent oil refineries in the northeastern and southeastern parts of the country. This project has been described as uneconomic by a number of observers and seems unlikely to be built as a stand-alone project. However, its goal of providing a connection between the western and eastern parts of the country may be met by the export pipeline being planned by China National Petroleum Company (CNPC) to connect Chinese projects in western Kazakstan with markets in China.

Oil transportation tariffs

The government of Kazakstan is considering the adoption of a new cost-of-service based pipeline tariff methodology. Developed with the assistance of USAID, the methodology is based on international standards and is intended to meet the needs of customers, international funding institutions and investors. Application of the proposed methodology (using a 15% rate of return for illustrative purposes) yields an average tariff of about US$ 6.75 per tonne per thousand km, compared to an average of about US$ 4.50 under the existing tariff system. A final decision concerning adoption of a new pipeline tariff methodology is expected by mid-1998. The new tariffs would be roughly equivalent to those charged by Russia's Transneft, though about half the rate expected for the CPC. (The CPC charge of US$25 per tonne from Tengiz to Novorossiysk implies a tariff of approximately US$14.75 per tonne per thousand km.)

Oil export

A major issue for most oil and gas development projects is access to export pipelines. Currently, all oil exported by pipeline must pass through Russia's Transneft system. As of mid-1997 the export capacity of the Kazak pipeline system via Russia was some 16 Mt per year: 13 Mt via the Atyrau-to-Samara (Russia) pipeline, and 2.6 Mt (design capacity 6.5 Mt) via the Aktyubinsk-to-Orsk (Russia) pipeline. (Kazakstan's import capacity is 24 Mt per year of Russian oil via the East Siberia to Central Asia trunk pipeline). However, Transneft has limited Kazak net exports to 6 - 10 Mt per year (7 Mt in 1997), allegedly due to capacity constraints caused by the export demands of Russia's own companies and joint ventures.

The export quota for the year is determined by an annual protocol between the Russian and Kazak ministries of energy, while Russia's Transneft decides actual monthly amounts according to technical and other factors.[11] A decree issued at the end of 1997 switches responsibility for fixing crude export quotas from Kazakoil to Kaztransoil.

The creation of an independent export route is a priority. Current plans call for construction of a dedicated line to a point near the Russian Black Sea port of Novorossiysk (see Caspian Pipeline Consortium, below). Although this pipeline will pass through Russian territory, it will not be under the control of Russia's Transneft.

Kazakoil's figures for gross crude oil and condensate exports by pipeline from Kazakstan between 1990 and 1997 are given in Table 8.

11. Russian legislation requires Kazak suppliers to present customs and freight documents to Transneft 20 days in advance of shipments.

Table 8 Kazak gross exports of crude oil and condensate by pipeline (Mt)

	1991	1992	1993	1994	1995	1996
Exports (gross)	21.1	21.8	20.2	17.4	12.9	13.5
of which to non-FSU	0	6.2	4.4	3.5	3.7	4.2
of which by Jvs	0	0.2	1.2	2.0	2.4	3.1

Source: Kazakoil.

Total Kazak oil exports historically have been significantly higher than net exports. This is due to the legacy of the Soviet pipeline system, which connects a number of important Kazak fields to Russian refineries, and vice versa.

According to IEA calculations, gross crude exports via all modes of transportation in 1996 may have been as high as 17.9 Mt, with net exports of 10.8 Mt. Gross oil exports by pipeline are estimated at 15.6 Mt (2.1 Mt higher than Kazakoil's figure), with a net figure of about 8.5 Mt. These figures can be broken down as follows:

- 3.4 Mt sent by pipeline to Russia in government-to-government swaps for Russian oil, in exchange for 3.16 Mt from Russia (net exports of 0.24 Mt);[12]
- 3.9 Mt sent by pipeline to Russia for refining on a commercial basis and received back as products (net exports of 0 Mt);
- 4.8 Mt sent by pipeline to other markets within the FSU, including 3.5 Mt to Ukraine (net exports of 4.8 Mt);
- 3.5 Mt sent by pipeline to destinations outside the FSU, all via Russia; mostly via Novorossiysk, though also via Ventspils and Odessa, and by pipeline to eastern Europe (net exports of 3.5 Mt);
- 2.3 Mt exported by rail and sea, approximately evenly split between these two modes; much of this was sent by Chevron from its Tengizchevroil joint venture (net exports of 2.3 Mt).

According to Kazakoil, gross exports in 1997 were 16.8 Mt.

Oil pipeline quotas

All Kazak producers, including joint ventures, are theoretically allowed to export all their production. However, Russian pipeline quotas have made this right difficult to implement in practice. Instead, producers' exports are more or less pro-rated to their production. (Thus joint ventures with foreign partners, which accounted for some 30% of Kazak oil production in 1996, accounted for roughly 30% of net oil exports by pipeline that year.) Each producer submits its export requests quarterly to Kaztransoil, which in turn submits an export plan to the Ministry of Energy, Industry and Trade for approval. All Kazak producers are also allowed to sign independent contracts with Russia's Transneft for additional shipments outside Kazakstan's general quota.

12. Kazakstan is obligated to supply at least 7.3% extra by weight to account for quality differences. Of the 3.16 Mt from Russia (supplied via the Omsk-Pavlodar-Shimkent pipeline), 2.85 Mt went to the Pavlodar refinery, and 0.31 Mt to the Shimkent refinery.

Oil exports by rail

Led by Tengizchevroil, a number of producers have exported oil by rail as a way to get round Transneft quotas. In the first nine months of 1997, Kazakstan exported some 5 Mt of oil via Russia, of which over 2 Mt was sent by rail. According to Tengizchevroil, advantages of rail shipments include flexibility and quality control, since the oil avoids the blending that can occur in pipelines.

The price of shipping by rail decreased in both Russia and Kazakstan in 1997. Russia lowered its tariffs by 25% in July 1997, and Kazakstan halved the return tariff for empty cars owned by Kazak-registered oil producers. However, transportation costs for oil sent by rail are still on average twice as high as for oil sent via pipeline. The ability to export by rail therefore depends significantly on the economics of individual fields.

Tengizchevroil began rail exports in July 1995, and in 1996 used this mode to deliver up to 60% of its monthly exports. Most of Tengizchevroil's deliveries were to Ventspils, Latvia, from whence the oil was sent by tanker for refining in Hamina and Porvoo, Finland. Tengizchevroil also sent oil by rail to the Ukrainian port of Odessa, to various locations in eastern Europe, and across Azerbaijan and Georgia to the Black Sea (after first shipping it by barge across the Caspian). The producer has been actively pursuing rail exports to a variety of customers, in part to test the market for its high sulphur Tengiz crude. In order to accommodate increased shipments it has built a 3-Mt capacity rail loading facility at Tengiz.

In November 1997 Tengizchevroil sent a test shipment of oil to China. The crude was purchased at the border by Sinochem for processing at a refinery in Xinjiang. Tengizchevroil intends to sign a contract to deliver as much as 100 kt per month (1.2 Mt/year) to China. Logistical difficulties to overcome include different track gauges between the two countries.

Hurricane Hydrocarbons (Canada), which operates the Kumkol field, also plans to ship oil to China by rail. It has set up a joint venture called Hurricane-Dostyk to build a rail transhipment terminal in Druzhba on the Kazak-Chinese border. The terminal is expected to open in July 1998 with a capacity of 1 Mt per year (20 kb/d). Hurricane- Dostyk has long-term plans to increase capacity to 5 Mt per year (100 kb/d).

China National Petroleum Corporation (CNPC), which plans to build a pipeline to China from its Aktobemunai (Aktyubinsk) and Uzen fields in Kazakstan, has also sent some of its Aktobemunai crude to China by rail.

Proposed oil export pipelines

Caspian Pipeline Consortium

The most advanced alternative to exporting Kazak oil via Russia's Transneft pipeline system is the Caspian Pipeline Consortium (CPC) project to construct a dedicated pipeline to a new loading facility near the Russian Black Sea port of Novorossiysk. However, by the beginning of 1998 it had run into difficulties securing rights of way with several regional governments in Russia, through whose territory the pipeline is to pass.

The CPC was formed in 1992 by the Governments of Kazakstan and Oman, which were later joined by the Russian government and several oil companies, notably Chevron and Mobil. Protracted negotiations, especially on the relationship between number of voting shares and actual capital inputs by the partners, delayed the signing of the so-called Shareholders' Agreement until December 1996. (The Kazak government ratified the Shareholders' agreement in March 1997, and the Russian government did so the following month.) A follow-up agreement on technical aspects of the projects was signed on 16 May 1997 in Moscow.

Table 9 Shares in the CPC as of November 1997

Shareholder	%	
Russian government	24	Represented by Lukoil, Rosneft and Transneft
Kazakoil	19	Former Kazak govt. holding
Oman government	7	
Kaz Pipeline Ventures	1.75	JV Kazakoil/Amoco (US); former Munaigaz holding
LukArco	12.5	JV Lukoil (Rus)/Atlantic Richfield (US)
Rosneft-Shell	7.5	JV Rosneft (Rus)/Shell (UK)
Chevron (US)	15	
Mobil (US)	7.5	
Oryx (US)	1.75	
British Gas (UK)	2	
Agip (Italy)	2	

The CPC pipeline is to run 1,440 km around the north coast of the Caspian Sea from the Tengiz field to the village of South Ozereyevka on Russia's Black Sea coast, 15 km north of existing port and storage facilities at Novorossiysk.[13]

The CPC is to make use of existing pipelines where possible, notably between Tengiz and the Russian city of Astrakhan. Construction of new sections is to begin in 1998 or 1999. The line was to be completed by September 1999, though may be delayed to 2000 or 2001. Construction of the loading facility near Novorossiysk is to be finished by August 2000.

The pipeline is to have a diameter of 1,000 mm and an initial capacity of 28 Mt/year (about 560 kb/d). The estimated cost for this phase is US$2.1 billion, to be paid for by the producer shareholders (as opposed to the government shareholders). Contractors are to be chosen by tender, with the winners forming joint ventures with Kazak or Russian firms.

Capacity will gradually be built up in four phases, primarily through the addition of new pumping stations, to reach 67 Mt/year (1.34 Mb/d) by 2012 - 2014. The estimated extra cost for this capacity enhancement is US$1.9 billion, to be paid for by the consortium as a whole (i.e., by both government and company shareholders).

13. Novorossiysk itself is one of Russia's busiest oil export points and has limited additional capacity. Terminal capacity as of mid 1997 was 35 Mt/year. Separate plans for a new crude oil berth would raise capacity by 15 Mt/year. The Russian Ministry of Fuel and Energy has also stated that annual capacity could be increased some 3-4 Mt/year through Transneft improving its delivery through pipelines leading to Novorossiysk. Transneft had earlier proposed that the CPC pay for upgrading and expanding facilities at Novorossiysk. An alternative terminus for the CPC is the village of Gelendzhik, south of Novorossiysk.

The transport tariff is to begin at around US$25/tonne from Tengiz to Novorossiysk.[14] Russian crude joining the pipeline at or after Kropotkin will be charged US$7.75 per tonne to Novorossiysk. Operating costs for the first phase are estimated at US$40 million per year. According to project estimates, the oil companies should recoup their investment after eight years of operation.

Project details

The CPC project involves modernising the existing 752-km line from Tengiz to Komsomolsk, building a new 480-km, 1,020-mm line from Komsomolsk to Kropotkin, and constructing a 258-km, 1,000-mm line from Kropotkin to a tank farm. Some 15 pumping stations are to be built between Kropotkin, Komsomolsk and Atyrau, while stations in Tengiz and Astrakhan will be upgraded. The project also includes the construction of 13 storage tanks of 100,000 cubic metres each, including five at the port near Novorossiysk, as well as three single point mooring (SPM) facilities near Novorossiysk. Two moorings will be constructed in the first phase, 5 km from shore, and connected to a new metering station on shore by two 1,070-mm under-sea pipelines.

In April 1997 the CPC awarded a US$50 million tendered contract to design and manage construction of the pipeline to a partnership of the Russian design institute Giprovostokneft and America's Fluor Daniel.[15] Subcontractors are to include Russia's Krasnodar-based Nipigazpererabotka, St. Petersburg-based Lenmorniiproekt, and Kazakstan's Kaspiimunaigaz. CPC has also called tenders for contracts worth a total of US$1.3 billion to build and modernise infrastructure in Russia, US$160 million for similar work in Kazakstan, and US$700 million to build the terminal near Novorossiysk. A tender for US$600 - 700 million of equipment is to be held during the first quarter of 1998.

Rights of way

The pipeline is to pass through Astrakhan region, Kalmykia, Krasnodar territory, Stavropol and Novorossiysk. Rights of way agreements must be negotiated with local governments in each of these Russian regions. A contentious issue has been demands by these regions for a portion of the capacity in the CPC pipeline for their local oil producers.

As of January 1998, the consortium still needed to complete several feasibility studies, environmental reports and rights of way agreements before construction could begin.

Capacity quotas

For the initial stages pipeline capacity will be split 66% to producers operating in Kazakstan, 25% to Russian companies, and 8% to the governments of Russia, Kazakstan and Oman. Distribution of shares at initial and full capacity is shown in Table 10.

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14. This works out to about US$14.75 per tonne per thousand km, compared to Transneft rates of about US$7 per tonne per thousand km. At the end of May 1997, Transneft charged US$21 per tonne for crude from western Siberia to Novorossiysk.
15. Fluor Daniel also won a tender in early 1995 to be contractor for the construction of the Azeri section of the AIOC pipeline to Novorossiysk.

Table 10 CPC pipeline quotas

	Stake in CPC	Capacity in 2000	Capacity in 2014
Kazakoil (incl. govt. share)[1,2]	19%	[2 Mt]	11.3 Mt (16.68%)
Russian government[2]	24%	[1 Mt]	4.8 Mt (7.16%)
Oman government[2]	7%	[1 Mt]	1.4 Mt (2.09%)
Kaz Pipeline Ventures JV[3]	1.75%	3 Mt	3 Mt (4.48%)
Lukoil (LukArco JV)	12.5%	4 Mt	10 Mt (14.93%)
Rosneft (JV with Shell)	7.5%	3 Mt	5 Mt (7.46%)
Chevron (US)	15%	4 Mt	15 Mt (22%)
Mobil (US)	7.5%	2 Mt	7.5 Mt (11.19%)
Oryx (US)	1.75%	2.7 Mt	3 Mt (4.48%)
British Gas (UK)	2%	2.75 Mt	3 Mt (4.48%)
Agip (Italy)	2%	2.75 Mt	3 Mt (4.48%)
	100%	24 Mt	67 Mt

1) The amount for 2014 includes 3.8 Mt given by the Kazak government to Kazakoil, in addition to Kazakoilís 7.5 Mt.
2) The government shareholders are to receive a joint total of 2 Mt in 2000. It has been assumed here that this amount will be divided between the Russian and Omani governments; the Kazak government already has 2 Mt assigned to it separately.
3) JV between Kazakoil and Amoco (former Munaigaz share).

Most of the pipeline's capacity is booked by CPC members for the next 40 years. Nevertheless, there are reportedly procedures by which other parties may lease capacity from CPC members.

Rosneft and Lukoil plan to pump Russian crude through the CPC line, probably from Kropotkin. Lukoil predicts that the pipeline will carry around 12 Mt per year of Russian oil from Siberia at full capacity. (Rosneft has no production in Kazakstan, though Lukoil has a 5% stake in the Tengizchevroil project and is a partner in the North Kumkol field.)

Evolution of CPC provisions

The original conception of the CPC, as developed by the Oman National Oil Company (which later left the CPC, although the government of Oman remains a shareholder), contained a number of negative features for potential shareholders. These included,

- an unacceptable ratio of shares to investment for the producing members (25% of the shares in exchange for financing 100% of the costs);
- high pumping charges; and
- projected tax revenues that were considered inadequate by the governments of Kazakstan and Russia.

A new conception of the CPC was agreed to in principal by the potential members in April 1996, and worked out in more detail in the Shareholders' Agreement of December 1996. Notably, it offers the companies 50% of the shares (instead of only 25%) in exchange for financing 100% of the cost. It also provides more revenue opportunities for the governments of Kazakstan and Russia, including taxes on profits, interest, dividend, property, repatriation, VAT on capital spending and services, customs duties, as well as local taxes.

Projected tax revenues

According to the CPC, the Kazak government stands to earn US$8.2 billion from the project. The Russian government calculates that it will earn some US$23 - 24 billion, mostly in transit charges, over the 40-year life of the project. By 2014 the CPC is expected to generate some US$900 million for Russia per year, about 22% of which is to stay in the regions through which the pipeline passes. However, given large central government deficits, some Russian regional administrations have expressed concern about the amount of CPC revenve they actually will be allowed to keep.

Shares in the CPC and financing plans

The Russian and Kazak government stakes represent the value of land and infrastructure they provided to the CPC. Notably, the Kazak government contributed 450 km of pipeline between Tengiz and Astrakhan. The Russian government donated a similar amount of pipeline between Astrakhan and Komsomolsk. Most pipeline contributed by the two governments is over 10 years old and will require reconstruction. The Oman government share corresponds to the US$87 million it invested in the project through 1996.

The Russian government gave its 24% share to Lukoil, Rosneft and the pipeline company Transneft to manage.[16]

The share of the Kazak government was transferred to the new national oil company, Kazakoil, in March 1997. At about the same time Kazakoil also inherited the share of the former oil and gas holding company, Munaigaz, when the latter was abolished. In March 1997, Kazakoil and Amoco (US) signed an agreement to form Kaz Pipeline Ventures, to finance the Kazakoil share previously held by Munaigaz. Under this agreement, Amoco is to provide all of the funding. The agreement will apparently give the US major access to the full quota formerly assigned to Munaigaz for exports via the CPC. The agreement covers other Amoco investments in Kazakstan as well (see below), for which this export capacity would be useful.

Lukoil is financing its share in the CPC via a joint venture with Arco. The LukArco JV will also fund Lukoil's purchase of a 5% stake in the Tengizchevroil project from Chevron. Similarly, Rosneft entered into a joint venture with Shell, called Rosneft-Shell Caspian Ventures Ltd.

CPC administration

For legal and tax purposes, two joint stock companies were created, CPC-Russia, and CPC-Kazakstan. All senior managers at CPC-Russia hold equivalent positions in CPC-Kazakstan, except for the chief liaison with the host government.

16. According to a government resolution signed by Prime Minister Chernomyrdin on 12 May 1997, Russia will fund part of its share in the CPC with some of the profits from VietSov Petro, an oil production joint venture between Russia's Zarubezhneft and Viet Nam's PetroVietnam, which is developing the White Tiger and Dragon fields in the South China Sea. Annual Russian profits from this joint venture amount to around US$150 million.

The Russian pipeline monopoly Transneft was made operator of CPC to maintain all facilities, including those on Kazak territory. However, its role is to be technical only and apparently will not include organisation of throughput schedules and allocations among shippers.[17]

CNPC pipeline to China

The development of oil export routes to China became more likely after the sale of Kazak oil producer Aktobemunai (Aktyubinskneft) to the China National Petroleum Corporation (CNPC), as well as the awarding to CNPC of exclusive negotiating rights to the Uzen field in September 1997. As part of CNPC's bid for Uzen, it promised in a framework agreement to submit detailed proposals for the construction of a pipeline to China.

Chinese preliminary proposals call for a pipeline stretching some 3,000 km from CNPC's Kenkiak and Zhanazhol fields in the Aktyubinsk region of western Kazakstan, to the Karamai oil deposit in Xinjiang province in western China. The first stage may be a line between Kenkiyak and Kumkol, followed by a continuation to the Chinese border. Initial capacity is expected to be around 20 Mt per year, rising eventually to 40 Mt per year.

Some sources claim that a pipeline from western Kazakstan to western China would need to transport as much as 50 Mt annually to be economically feasible. Even to fill the first 20-Mt stage of the pipeline, CNPC would have to find additional sources to supplement the 10 - 13 Mt/year it would be able to supply from its Aktobemunai and Uzen fields.[18] According to Kaztransoil, Russia probably could make up the remainder.

Annual Chinese oil demand is growing at 8% per year. Anticipated annual net oil import requirements are 45-50 Mt by 2000, and 100 Mt by 2010. Increasing reserves is part of the Chinese government's five-year economic plan for 1996-2000. Although an export pipeline from Kazakstan to China may not currently be economical for CNPC, the Chinese government appears to be interested in maintaining some strategic control over future sources of supply outside its territory. It is therefore expected that the Chinese government could arrange credit for CNPC on favourable terms.

A line bringing Kazak crude to western China may also provide the critical mass needed to justify a potentially costly Chinese internal pipeline from Xinjiang to consumption centres further east. Xinjiang, which currently accounts for some 11% of Chinese oil production, is expected to account for the bulk of additional Chinese output over the next decade.

Besides providing a new outlet for Kazak oil that would be independent of Russia, such a pipeline could connect oil resources in the west with the Pavlodar and Shimkent refineries in the northeastern and southeastern parts of the country, in turn helping Kazakstan to decrease

17. At the signing of the 16 May 1997 agreement, Russian Minister of Fuel and Energy, Boris Nemtsov, called the CPC "healthy competition" for the Transneft system. "We can now compare Transneft's effectiveness with this new consortium...I hope this will reduce pipeline tariffs and in a unique way de-monopolise Russia's oil pipeline systems." FSU Energy 23/5/97.

18. There may be some problems in transporting the highly paraffinic Uzen oil over long distances. It may need to be blended with other oils.

dependence on Russia and other neighbours for crude supplies to these refineries. Such a pipeline for internal use has been considered for a number of years.

The Kazak pipeline company Kaztransoil expects tariffs on the Kazak section of the pipeline to be around US$4 per tonne. Kaztransoil would like to set up a 50/50 consortium with CNPC to build the pipeline, with capacity and allocation decisions determined jointly by consortium members. CNPC, on the other hand, prefers a build-operate-transfer (BOT) structure, under which it would own the pipeline for a specified period of time. The estimated cost of the Kazak section is US$2.6 billion. Work on the pipeline is expected to take six to eight years, making completion of the project some time before 2004 unlikely.

Via Turkmenistan to Iran

The framework agreement signed between CNPC and the Kazak government in September 1997 also calls for the Chinese company to submit bids to build an oil pipeline to Iran. The initial stage would be a 200-km pipeline from Kazakstan to the border with Turkmenistan, to be extended later. It is unclear whether CNPC and the Kazak government view this as an addition, or an alternative, to the proposed pipeline to China. Both parties may be hedging their bets on the chance that in the future routes via Iran will become politically more acceptable and/or the cost of a pipeline to China will prove prohibitively high.

Total (France), as well as a group of US majors, are reportedly also studying the feasibility of building an oil pipeline from Kazakstan via Iran to the Gulf.

Transcaspian pipeline

Amoco, at the request of the Kazak government, is conducting a study to lay a pipeline under the Caspian Sea. Known variously as the "Caucasian Corridor" or "Eurasian Corridor", such a pipeline probably would use some of an existing line near the Tengiz field and cross the Caspian near Kazakstan's border with Turkmenistan. From there it would go to Baku, and then either across Georgia to the Black Sea, or across Turkey to the Mediterranean port of Ceyhan. There are reportedly 12 variants being studied. A feasibility study is due to be completed in 1998.

Via Azerbaijan and Georgia

Several non-pipeline export projects are already fairly advanced, though these are generally thought of as temporary measures until sufficient pipeline capacity becomes available.

In October 1996 Tengizchevroil signed a deal with Azerbaijan's state oil company, Socar, to ship Tengiz crude across the Caspian by tanker to Azerbaijan and from there across Georgia by rail to the Black Sea. Some 50 kt per month of Tengiz crude are to be shipped from Aktau in Kazakstan to Azerbaijan's Dyubendy seaport. From there the oil will go by pipeline to Ali

Bayramli in western Azerbaijan, from whence by rail to the Georgian port of Batumi for shipment to Mediterranean customers. The first train carrying 2,400 tonnes reached Batumi in March 1997.

Caspian Transport Company, a subsidiary of Brown and Root, has leased two pipelines[19] from Azeri state oil company SOCAR, joined them together and repaired a number of pumping facilities. It is envisioned to eventually increase exports via this route to 200 kt per month, depending on its effectiveness. Total volumes by this route in 1997 were expected to be around 2.5 Mt. Chevron reportedly lifted its first cargos of Tengiz crude from Batumi in April 1997.

The cost of shipping the oil across the Caspian Sea was reportedly US$6 per tonne in 1997, and US$8 per tonne across Georgia to the Black Sea.

Ukraine has proposed a continuation of the Azeri/Georgia route that involves transit of Central Asian and Transcaucasian oil across Ukraine. Oil would be shipped across the Black Sea from Georgia (or conceivably from Novorossiysk) to an import terminal Ukraine is building near Odessa in order to diversify its oil supplies. In addition to purchasing oil for its own use, Ukraine proposes sending oil via the Druzhba pipeline to European refineries and/or Baltic ports. Ukrainian experts reportedly have calculated that it would cost US$33 - 37 per tonne to send Kazak oil via Ukraine to northern Europe, inclusive of transit charges from Kazakstan to Ukraine.[20] However, financing problems so far have halted construction on the terminal several times.

Swaps with Iran

A memorandum signed by the Kazak and Iranian presidents in May 1996 opened the way for deliveries of Kazak crude oil by ship to Iran's Caspian Sea port of Neka in exchange for Iranian exports of equal value from the Persian Gulf. The 10-year agreement calls for Kazakstan to deliver 1 - 2 Mt in 1997 and to increase shipments to 6 Mt per year by 2000. The Kazak crude is to be refined at the Tehran and Tabriz refineries in northern Iran (probably after first being blended with Iranian Light crude). Normally these two refineries process crude sent to them by pipeline from Iran's southern coast.

Initial test shipments to Iran began in January 1997. (The Caspian Steamship Line reportedly charging US$14 per tonne of oil delivered between Aktau and Neka.) A total of 70 kt was delivered before shipments were halted due to disagreements regarding quality of the Kazak blend, a mix of Mangistau and Tengiz crudes. The Iranians insisted it was too sulphurous and contained too many mercaptans, an accusation similar to that levelled several years earlier by Transneft when it refused to accept Tengiz oil through its system. The Kazaks maintained that the oil met quality guidelines set out by the contract. (The scheme had been delayed

19. From Dyubendi to Dashkil (300 mm), and from Dashkil to Ali Bayramli (500 mm), for a total of 200 km. The Ali Bayramli - Dashkil line, which used to move oil for refining in Baku, had to be reversed. Before the combined pipeline was opened in March 1997, oil arriving at Dyubendy was swapped with Azeri oil in Ali Bayramli.

20. Interfax 14/3/97.

previously, in 1996, due to an Iranian request to be compensated for refitting its refineries to accept the Kazak crude.)

Another problem has been that Iran's Caspian Sea terminals at Neka do not have adequate facilities for unloading crude oil. Moreover, the crude must be sent from Neka to the refineries at Tehran and Tabriz by rail, making transport expenses high.

The swaps, halted in March 1997, were to be restarted later in 1997 after a new agreement on the mix of Kazak crudes, cutting the share of Tengiz from the original 50% to 20%, and raising the share of crude from Buzachi. However, further disagreements reportedly halted shipments again.

In order to comply with foreign sanctions on Iran, the oil shipped was owned by the Kazak state oil company and not the western partners in Tengizchevroil. The swap was found to be consistent with US foreign policy by the US Treasury Department's Office of Foreign Asset Control, the body which oversees US sanctions against companies doing business with Iran. (A clause was added to US sanctions legislation in 1995 which specifically excludes hydrocarbon swaps with Iran by Kazakstan, Azerbaijan and Turkmenistan.)

According to some sources, Iran could absorb up to 650 kb/d of swapped crude for its northern refineries. However, the investment needed to facilitate such swaps by pipeline would be greater than the limit allowed by US Iran-Libya sanctions legislation. It reportedly would cost US$ 120 - 140 million to link the Iranian Caspian port of Bandar Anzali to an existing crude pipeline serving the Tehran and Tabriz refineries, which have throughput capacities of 220 kb/d and 80 kb/d, respectively. A further investment of US$ 500 - 600 million reportedly would be needed to reach several other refineries (including Isfahan and Arak) in order to raise the capacity for swaps to 650 kb/d.

GAS RESERVES AND PRODUCTION

Kazakstan's natural gas reserves are estimated at some 4 trillion cubic metres, of which about 1.5 - 2.35 trillion are considered proven. More than 40% of currently recoverable reserves are located in the Karachaganak field in western Kazakstan.

According to Kazakoil, natural gas production in 1997 was 6.09 Bcm, down somewhat from 6.16 Bcm in 1996, though up slightly from the 5.9 Bcm produced in 1995. (The recent decline appears to be related to difficulties in exporting gas via Russia.) A high of 8.1 Bcm was reached in 1992. In recent years about one third of total gas production has been associated gas. An additional estimated 1 Bcm has been flared annually due to lack of pipelines to bring associated gas to consumption areas.

Currently most gas is produced from the Karachaganak field. Other significant gas producing fields are the Tengiz and Zhanazhol, which are also major oil fields. The Uritau gas field in the Aktyubinsk region is expected to become Kazakstan's third largest gas producer in the longer term.

Similar to the situation for crude oil, gas production and consumption centres in Kazakstan are distant from each other and not well connected, so that although the country is a net importer, it exports much of its own production to Russia while importing most of the gas it actually uses from Turkmenistan and Uzbekistan. An expanded transmission network to eliminate the need for such imports is a priority of the Kazak government.

Given the inherited pipeline structure, the World Bank has suggested that priority fields for development could include those close to existing networks and consumer centres in the South of the country. For example, the Amangeldi and other fields close to Zhambyl could produce up to 3 Bcm per year.[21]

The link between oil and gas development is an important consideration for the government. Since a substantial expansion of liquid production will result in a corresponding increase in associated gas output, it is conceivable that, in the absence of an appropriate gas strategy, oil and condensate production could become constrained due to problems posed by the disposal of gas.
Another important link between oil and gas is that gas could substitute for oil and coal in some sectors (e.g., in the residential and power generation sectors and, eventually, even in transportation), thus releasing more oil for export.

In the IEA scenarios, gas production is forecasted at 8 -10 Bcm in 2000, and 15-29 Bcm in 2010. (See chapter, Projections of oil and gas production, domestic demand and exports.)

GAS PROCESSING, TRANSMISSION AND DISTRIBUTION

Kazakstan has three gas processing plants (GPZs):

- Kazak GPZ, with 6 Bcm of annual gas processing capacity;
- Zhanazhol GPZ, with 4 Mt of annual crude and condensate preparation capacity, and 0.8 Bcm of annual gas processing capacity;
- Tengiz GPZ, with 0.85 Bcm of annual gas processing capacity.

Only the Kazak GPZ is involved exclusively in gas processing, while the Zhanazhol and Tengiz plants handle crude oil preparation as well. Given that most Kazak gas is sour, further gas processing infrastructure will be required to improve its marketability.

Kazakstan's gas transmission and distribution network comprises 7,000 km of pipeline, including a 400-km section of the Soyuz line that exports Russian gas to Europe, and transit pipelines that bring Uzbek and Turkmen gas to Russia. The system contains 16 compressors, 82 gas distributing stations, and the Bazoiskoye underground storage facility with a capacity of

21. Kazakstan: Natural gas investment strategy study, draft report, May 1997, World Bank.

3.6 Bcm. The transmission system handled some 50 Bcm in 1996, much of which was in transit from Turkmenistan.

Gas transmission

Table 11 Major gas transmission pipelines in Kazakstan

	Diameter mm	Capacity Bcm/yr	Utilisation in 1995 (%)	Wear rate (%)
Central Asia - Centre gas pipeline system	1,020-1,420	67.5	28	60
Makat - North Caucasus (Kazakstan - Russia)	1,420	25.5	70	26.7
Okarem - Beineu (Turkmenistan - Kazakstan)	1,220	5.4	18	100
Uzen - Aktau (Kazakstan)	1,020	3.6	18	n/a
Orenburg - Novopskov; Orenburg - western border (Russia - Russia)	1,220	58.4	50	60
Kartali - Kostanai (Russia - Kazakstan)	1,220	5.4	20	20
Bukhara - Ural (Uzbekistan - Russia)	1,020	14	25	100
Bukhara - Tashkent - Bishkek - Almaty (Uzbekistan - Kazakstan)	1,020	13	n/a	n/a
Gazli - Shimkent (Uzbekistan - Kazakstan)	1,220	13	n/a	25

Source: Russian Petroleum Investor, December 1996

Until June 1997 gas transmission was handled by two state-owned holding companies, Kazakgaz and Alaugaz. Kazakgaz operated and maintained pipelines, compressor stations and storage facilities in gas-producing western Kazakstan. It acquired gas from production and processing enterprises, transported it via the transmission network, and sold it to large industrial customers and distributors in the western part of the country. Kazakgaz also provided transit services for Turkmen and Uzbek gas exports to and via Russia. A portion of Turkmen and Uzbek exports to Russia are actually Kazak gas, in exchange for Turkmen and Uzbek gas imported into southern Kazakstan.

Most gas imports go to the southern Alaugaz network, which is not connected to the western network and remains almost completely dependent imports via Uzbekistan.

Transit of Turkmen gas used to supply most of the transmission system's income.[22] However, even before Turkmenistan halted exports of gas via Kazakstan in March 1997, the gas transmission

22. Turkmenistan pays Kazakstan a transit fee equal to an additional 18% of the amount it sends across the latter's territory. For example, in exchange for the transit of 17.2 Bcm in 1995, Turkmenistan paid Kazakstan 3.1 Bcm.

system experienced serious non-payments difficulties which made it a major drain on the central budget. By the beginning of 1997, Kazakgaz was owed some 20 billion tenge by large customers and distribution companies, and in turn owed the government several billion tenge. The government decided to look to private investors to help improve the transmission companies' payment situation.

In 1996 the government organised a tender to run the Kazakgaz and Alaugaz networks on a concession basis. In February 1997 Bridas (Argentina) was declared the winner. However, the government voided the results of the tender in mid-April 1997 and opened negotiations with several other firms. In June 1997 it awarded the transmission concession to Tractabel (Belgium), with which it signed a 15-year agreement with the option to renew for a further five years.[23]

Tractabel formed a company called Intergaz Central Asia, which took over the pipelines, compressors, equipment, buildings, land and employees of Kazakgaz and Alaugaz, but not the legal entities themselves. Intergaz Central Asia was not required to take over the debts or social responsibilities of the two transmission companies. It was, however, required to invest US$600 million in the system over 15 years.

Intergaz Central Asia's priority during the first year of operations was to improve and rationalise the transmission system. Pipeline wear in 1997 averaged 70%, and losses in the western system were 11% (compared to some 4.5% in most OECD countries). Intergaz estimates that the investment needs of the gas transmission system, not including new pipelines, are US$500 million. According to other sources, the cost of full modernisation and expansion of the system could be as high as US$3 billion.

Before the transmission system was taken over by Tractabel, Kazakgaz drew up plans for several new gas pipelines, particularly in the northern and eastern parts of the country, to connect major production and consumption areas and alleviate the need for imports. However, most of these projects would require significant investments that probably would be uneconomic under the current tariff system. The only major new pipeline currently envisioned by Intergaz is a loop to bypass part of the southern system that dips into Kyrgyzstan, which reportedly routinely has taken gas without fully compensating the Kazak system. (Kyrgyzstan pays for much of its gas in electricity and water.) Intergaz is required to start work on the bypass project one year from the date new tariffs are introduced. The new transportation tariffs, which should allow Intergaz to cover long run marginal costs, are expected to be approved before the end of 1998. All tariffs must be approved by the State Committee for Price and Anti-monopoly Policy.

23. According to Tractabel, its contract covers the operation of all high pressure pipelines on Kazak territory, apparently including the Kazak portion of any new export pipelines built by other parties.

Table 12 New gas transmission lines proposed by Kazakgaz

Route	Length (km)	Diameter (mm)	Estimated cost (US$ million)
Aksai - Krasny Oktyabr - Kostanai - Kokshetau - Akmola	1,800	1020	1100
Chelkar - Shimkent	1,216	720	347
Uzbekistan - Kazakstan	150	720	150
Akmola - Karaganda	246	720	136
Akmola - Pavlodar	196	720	105
Pavlodar - Ust-Kamenogorsk			
Aktyrtobe - Almaty - Taldy-Kurgan			

Source: Russian Petroleum Investor, December 1996

In September 1997 Intergaz reversed the flow of the Bukhara-Ural pipeline, which used to send gas to Russia, in order to import Russian gas to replace some of that which used to come from Turkmenistan. Much of the Russian gas, which was purchased from gas trader, Itera, was pumped into Kazakstan's Bazoi gas storage facility and used to cover peak demand during Winter.

Tractabel set up a separate company, Swiss-registered Global Gas Group (GGG), to buy the gas that is shipped by Intergaz Central Asia. GGG purchases gas from the main Kazak producers, Karachaganak (2 Bcm/year) and Tengizchevroil (1.5 Bcm/year), as well as from exporting countries. Although Tractabel is involved in both gas sales and transport, Kazak pipelines are by law open to third party access.

According to Intergaz Central Asia, the main attraction of the Kazak gas transportation system is its potential as a major transit hub. In the Kazak market itself, gas must compete with low cost, though highly polluting, coal. According to Intergaz Central Asia, the market for gas in power generation is likely to grow in Almaty, where another branch of Tractabel runs the electricity utility. However, the power market for gas is less clear in other parts of the country, including the new capital, Akmola, which is situated near extensive coal fields.

Investment needs

The World Bank has identified the following projects in the gas sector as priorities, subject to detailed feasibility studies:[24]

- Karachaganak field gas processing plant (initial phase annual capacity: 4 Bcm; initial phase cost: US$100 million)
- Flared gas capture from the Zhanazhol field and its utilisation for power generation (US$140 million)
- Flared gas capture from the South Turgai fields and its utilisation for power generation (US$100 million)

24. World Bank, 1997.

- Development of the Amangeldi and other Zhambyl region fields (US$276 million)
- Rehabilitation of the Central Asia-Centre gas pipeline (US$110 million)
- Installation of meters at border locations (US$78 million)
- Rehabilitation of local distribution facilities in Almaty and South Kazakstan oblast (US$30 million).

Gas distribution

Prices for natural gas are determined by regional governments according to criteria developed by the State Committee for Price and Anti-monopoly Policy. Beginning in 1997 all gas prices were to cover all costs, including transport and long run development costs, plus profit.[25] However, non-payment remains a major problem. Although distribution companies have the right to cut off customers, it is unclear how much they actually are allowed to do so by local authorities.

In part because of the non-payment problem, many Kazak gas distributors were sold to local investors in 1996 and 1997 (though actual pipelines remained under government ownership). However, most continued to fall deeper into debt. In October 1997 the government asked Accept Trading Company to take over all local distributers and assume their debts. Accept reportedly will be required to pay all gas transport fees to Intergaz Central Asia in advance.

Table 13 Kazak gas distribution companies

Akmola Gas Supply
Almaty Gas Supply
Zhambyl Gas Supply
Zhezhkazgan Gas Supply
Karaganda Gas Supply
Kzyl-Orda Gas Supply
Kokshetau Gas Supply
Pavlodar Gas Supply
North Kazakstan Gas Supply
Taldykorgan Gas Supply
Temirtau Gas Supply
Turgai Gas Supply
South Kazakstan Gas Supply

GAS TRADE

Kazakstan handled the transit of some 17.20 Bcm of Turkmen gas in 1996, for which it received approximately 3.15 Bcm in transit payments. In addition, it swapped approximately 2.34 Bcm with Uzbekistan. (Gas imports from Uzbekistan to southern Kazakstan are subject to frequent suspension of supply). Currently Kazakstan does not export gas on its own account outside the

25. Due to lack of meters in the residential sector, charges are determined by formulae based on number of persons, floor space and use. According to the State Committee for Price and Anti-monopoly Policy, the typical monthly gas bill in 1997 for an apartment heated by gas was 3-4 thousand tenge, and 40 tenge per person for an apartment that only used gas for cooking.

Central Asian region. Potential gas exports to Europe must traverse Russia, which has refused to grant Kazakstan a quota for gas exports, citing capacity limits.

According to Kazak officials, the country is looking at various routes to bring gas to the international market, including

- via Afghanistan to Pakistan and India;
- under the Caspian Sea to Azerbaijan and on to Turkey;
- via Turkmenistan to Iran and Turkey; and
- to China and Japan.

Most of these proposals essentially consist of connection lines to proposed pipelines anchored in Turkmenistan, which is expected to supply the bulk of gas exports from the region. (See Turkmenistan chapter.)

Table 14 Kazak gas production, export and import (Bcm)

	1993	1994	1995	1996	1997 (Jan-Aug)
Production	6.69	4.49	5.92	6.52	5.27
Export	3.45	1.64	2.57	2.34	1.51
Import	9.77	7.17	9.12	5.49	2.30

Source: Kazak National Statistical Agency

In Table 14, the 1993-1996 figures for exports appear to consist only of gas sent to Uzbekistan or to Russia as part of a swap arrangement with Uzbekistan; the corresponding import from Uzbekistan is apparently shown within the import column, with the difference representing Turkmen gas received as a transit fee. Swaps occurring as part of the transit procedure for Turkmen gas do not appear to be included in the figures.

INVESTMENT

According to Kazakoil, total foreign direct investment in Kazakstan's oil and gas sector in 1996 was around US$410 million, of which almost US$100 million went into the Tengiz field. In 1997 these figures were US$627 million and US$346 million, respectively. According to Kazakoil, direct foreign investment in Kazakstan's oil and gas sector from 1991 through 1996 was around US$2 billion. Some US$167 million of this consisted of bonuses, and about US$133 million of royalties.

In October 1997 Nurlan Balgimbayev, then head of Kazakoil, estimated that Kazakstan needed a total of US$160 billion to develop all of its oil reserves, US$10 billion of which were needed for exploration. Total plans for new foreign direct investment as October 1997 stood at over US$35 billion. (Some estimates go as high as US$65-79 billion.)

Table 15 Foreign direct investment in Kazak oil and gas sector (US$ million)

	1992	1993	1994	1995	1996	1997
Total for year	28.6	316.7	644.6	499.2	409.6	627.0
of which in Tengiz	0	165.0	472.0	231.0	99.2	346.0
of which in Karachaganak	0	0	0	38.8	73.6	65.0 (est.)

Source: Kazakoil

In October 1997 President Nursultan Nazerbayev released the government's "Programme for the Social and Economic Development of Kazakstan until 2030". This programme calls for the oil and gas sector to serve as a major driving force behind the country's future economic development.

In parallel with the release of the report, President Nazerbayev replaced reformist prime minister Kazhegeldin with the then head of Kazakoil and former minister of oil and gas, Nurlan Balgimbayev. Balgimbayev is known and generally well respected by western oil executives operating in Kazakstan. He has also taken business administration courses at MIT and spent a year training with Chevron in the US. Nevertheless, he has been an outspoken critic of privatisation, and is expected to demand tougher terms from foreign investors. It appears that the terms of individual foreign investment projects will be scrutinised more closely than in the past and tailored to the project, as opposed to past emphasis on building up a body of law applicable to all contracts.

From various remarks by President Nazerbayev and Prime Minister Balgimbayev, it also appears that Kazakoil is to play a more central role in the development of the Kazak oil and gas sector. However, the modalities of this role remain to be defined.

Table 16 Shares owned by Kazakoil in joint ventures with foreign firms

Joint venture	Kazakoil Share (%)	Foreign partner(s)
JV Tengizchevroil	25	Chevron (US), Mobil (US)
JV Arman	50	Oryx (US)
JV Damunai	50	
JV Kazturkmunai	51	TPAO (Turkey)
JV Embavedoil	52.7	Vedepser and MOL (Hungary)
JV Gyural	69	Urals Trading (Cyprus)
JV Zhetibay-Quest	50	Mannai (Qatar)
JV Tengizmunaigaz-Telf	69	Telf (Switzerland), Katzer (Czech)
JV Karakudukmunai	50	MTI, Middle Eastern Oil Co.
JV Tenge	50	Anglo-Dutch Petroleum (US)
JV Turan Petroleum	25	Hurricane Kumkol Munai (Canada)
JV Tuplar Munai	50	
JV Stepnoi Leopard	50	Snow Leopard Resources
JV Aktobe-Preussag	50	Preussag Energy (Germany)
JV Shagirli-Shomishti	72	Kastor, AKPO
JV Tasbulat Oil Devlpt.	50	
JV Airmax	30	
JV Kilish	50	

Source: Government Order N. 410 of 24 March 1997 and updates provided by Kazakoil

State Committee for Investments

The State Committee for Investments was formed in November 1996 in response to complaints from foreign investors about the bureaucratic hurdles they faced doing business in Kazakstan. In order to give the committee weight, it is headed by the First Deputy Prime Minister, Akhmetzhan Yesimov, and reports directly to the President. The committee promotes itself as a "one stop shop" for foreign investors. Its mandate includes the following responsibilities:

- co-ordinating the activities of various government ministries and departments vis à vis the investor;
- negotiating and signing contracts for projects on behalf of the government;
- providing low interest loans and tax and customs privileges to investors;
- developing and submitting proposals for improving investment legislation; and
- promoting foreign investment in Kazakstan through provision of information.

Priority sectors are infrastructure development, processing and manufacturing, projects in Akmola, agriculture, tourism, sport and the social sector.

In September 1997 the State Committee for Investments was given the authority to grant licences and sign contracts for projects involving sub-soil use, including oil and gas extraction. However, oil and gas are not technically considered "priority sectors", meaning projects in this area are less likely to receive special privileges, such as tax breaks. (This is in line with IMF advice against special tax concessions for this sector.) As of the end of 1997, Goskominvest had yet to build up significant oil and gas expertise on its staff.

Foreign investment methods

There are three main ways for investors (including foreign investors) to participate in Kazakstan's oil and gas sector:

- **Licence:** Investors may apply for licences to explore and produce in unlicensed territory, including that in which no discoveries have yet been made. The general rules applying to licences, which may be offered in various ways, including competitive tender, are contained in the Presidential Decrees, "On Subsoil and Subsoil Use" of 27 January 1996, and "On Oil" of 28 June 1995. The Government issues licences, on the basis of which the Competent Body may conclude a contract with an investor. There is a provision for concluding production sharing agreements (PSAs), although as of the beginning of 1998 the practice was not common in Kazakstan.
- **Joint venture:** Foreign investors may establish a joint venture with a Kazak joint stock company. This is particularly applicable for rehabilitation projects. Other general rules are laid down in the Presidential Decree, "On Economic Partnerships".
- **Privatisation and share purchase:** Foreign investors may purchase shares in existing joint stock companies either from those companies themselves or at tenders organised by the State Property Committee. (See Privatisation and Stock market, below)

Major exploration and production projects

As of November 1997 there were 18 joint ventures working 42 fields and exploring approximately 71,000 km^2. Joint ventures with foreign firms accounted for about one third of oil produced in Kazakstan in 1997.

Major joint ventures with foreign firms include the following:

Tengizchevroil

New oil development in Kazakstan has focussed on the Tengizchevroil (TCO) joint venture, which Chevron (US) began pursuing before the breakup of the Soviet Union. In April 1993 Chevron signed a 40-year, 50/50 joint venture with Kazak partner Tengizmunaigaz. Mobil (US) bought half the government's stake in 1995 and in early 1997 Lukoil, though its Lukarco joint venture with Atlantic Richfield, bought a 5% share from Chevron. Lukoil reportedly has an agreement with the Kazak government for first refusal if the latter decides to sell more of its shares. Shareholdings in Tengizchevroil as of January 1998 were as shown in Table 17.

Table 17 Distribution of shares in Tengizchevroil

	%
Tengizmunaigaz/Kazakoil	25
Chevron (US)	45
Mobil (US)	25
Lukarco (JV between Lukoil and Atlantic Richfield)	5

The Tengiz field has estimated recoverable oil reserves of 6-9 billion barrels. Production in 1997 was reportedly 139 kb/d, for an estimated total of 7 Mt. Annual production levels are expected to reach 8.5 Mt by the end of 1998 and 11 Mt by the end of 1999. According to Tengizchevroil, field operating costs are below US$2 per barrel.

Even at production levels of 160 kb/d the venture has been profitable, according to Chevron, which reported that TCO posted profits of US$80 million after taxes in 1996, up from only US$1 million in 1995. The Kazak government reportedly made over US$120 million from the project in 1996 in the form of royalties, taxes, cash distributions and pipeline and rail fees. The Kazak government estimates that from a total US$25 billion in direct investment by the foreign partners over 20 years, the project should yield profits of over US$150 billion, of which Kazakstan's share will be US$114 billion. (Kazakstan is to receive 76% of all revenue from the field.) Because of oil export restrictions, actual investment volumes by the foreign partners were sharply reduced in 1996. However, they reportedly spent more than US$300 million in 1997 on drilling and installation of new equipment, and during the three-year period 1997 - 1999 expect to spend some US$1 billion.

Like other investors in Kazakstan's oil sector, Tengizchevroil has faced problems with access to export pipelines. In 1996 Russia's Transneft allowed the venture to export only 3 Mt (60 kb/d).

However, Transneft occasionally has opened further pipeline capacity for the venture to send additional oil for processing at underutilised refineries in southern Russia.[26] In March 1997 TCO exported 325 kt (76.5 kb/d) of crude via the Russian pipeline system, of which 49% went to Germany, 22% to Odessa, and a similar amount to Lithuania. At the insistence of Transneft, Tengizchevroil has built a plant to reduce the amount of corrosive mercaptans in its oil prior to shipping.

Assuming the Caspian Pipeline Consortium (CPC) project is built to schedule, production from Tengizchevroil is expected to peak at 35 Mt by 2010. During the first phase of the CPC, Tengizchevroil will have access to 12 Mt of the pipeline's annual capacity.

In the meantime, TCO has been sending small quantities of oil across the Caspian to Azerbaijan for further shipment by rail from Dyubendi to the Georgian Black Sea port of Batumi, as well as by a combination of pipeline from Dyubendi via Dashkil to Ali Bairamli, and from there by rail to Batumi. Chevron is to help finance reconstruction of Azerbaijan's Dyubendi port, and construction of a new pipeline from Dashkil to Ali-Bairamly. These measures reportedly are expected to save 20% off Chevron's US$32/tonne onshore transportation costs between the Caspian and Black Seas. Caspian Trans Co, a subsidiary of Brown and Root, is building a 46-km pipeline parallel to the existing one it is renting from Socar. It is to have a diameter of 300 mm and an annual capacity of 7 - 8 Mt. The new line was scheduled for completion by mid-1998.

TCO also has sent oil by rail across Russia, as well as to the Ukrainian Black Sea port of Odessa, to Ventspils, Latvia and to Tallinn, Estonia. As discussed elsewhere, the Kazak government has shipped some of its share of Tengiz oil across the Caspian Sea to Iran in exchange for Iranian oil exported from the Persian Gulf.

Kazak Shelf

An international consortium including Agip, BP/Statoil, British Gas, Mobil, Royal Dutch/Shell, Total, and Kazak partner KazakstanCaspiShelf (KCS), signed an agreement in December 1993 to perform a two-year geophysical and seismic study of the Caspian Sea shelf offshore Kazakstan. The consortium began field work in September 1994, which lasted until December 1996. Investing around US$218 million, it shot 26,180 km of seismic profiles in an area of 100,000 km^2.

The shelf was later divided by the government into 200 exploration blocs of 500 km^2 each. The exploration consortium members received first pick of 12 exploration blocks under a 40-year PSA agreement signed in Washington in November 1997. The six foreign partners share each of the blocks under a Shell-managed consortium called, Offshore Kazakstan International Operating Company (OKIOC). KCS, the offshore division of Kazakoil created for the original exploration work, will be carried in the new project by the foreign partners. KCS also received two blocks to develop separately. A further two blocks were given to Oman Oil Corporation, which plans to develop them with Union Texas Petroleum (US).

26. In February 1997 the venture contracted to send a 30,000-barrel cargo of crude to Russia's Astrakhan refinery. TCO maintained title to the oil, paying only for the refining. It planned to sell the resulting products in Russia.

Tenders for the remaining blocks are to take place in 1998 or 1999. Terms for the tenders have yet to be developed, though winners reportedly will sign production sharing agreements.

Kazak government estimates of offshore reserves are around 10 billion tonnes. However, western consortium members downplay the government claims, stressing that exploration wells have yet to be drilled. Other sources place the reserve figures between 3 - 8.2 billion tonnes of oil, and 2 Tcm of gas, though this may be just for the licensed blocks.

According to some OKIOC members, there is a possibility of striking high pressure, sour gas, though the consortium so far has operated on the assumption that there will be no large gas fields offshore Kazakstan.

The first well is scheduled to be drilled during the second half of 1998. Winter drilling is difficult in the northern Caspian due to ice during four months of the year. Another obstacle in this part of the sea is the shallowness of the water (3-8 metres), which requires rigs and support craft different from those used in the deeper southern Caspian. The northern Caspian also constitutes a more fragile eco-system, and the consortium reportedly has spent large amounts of time and money performing environmental impact assessments.

Most western members of OKIOC estimate production will begin no sooner than 2004, at around 5 Mt per year (100 kb/d), possibly rising to 60 Mt (1.2 million b/d) by 2013.
Investment by the OKIOC could reach US$20 billion over the life of the project. The Kazak government expects total investment in the Kazak shelf to be around US$150 billion.

Karachaganak

Over half of Kazakstan's gas reserves are estimated to lie in the Karachaganak field. One western estimate places Karachaganak proven reserves at 800 Bcm of natural gas and 330 Mt of oil and gas condensate.

In 1992 British Gas and Agip won an international tender for exclusive negotiating rights to Karachaganak. In 1994 Gazprom signed an agreement with the Kazak Ministry of Oil and Gas to take part in the project. This was followed by an intergovernmental agreement between Russia and Kazakstan in February 1995. In March 1995 British Gas, Agip and Gazprom signed a temporary Production Sharing Principles Agreement, under which they agreed to finance work to boost output from the field. Gazprom decided to leave the project during the summer of 1996. A final production sharing agreement was signed in November 1997 in Washington. In the interim, Lukoil bought Gazprom's share, and Texaco took a 20% share from British Gas and Agip. Shares as of the end of 1997 are show in in Table 18. Investments in the project are expected to total US$10 billion over 40 years.

Table 18 Distribution of shares in Karachaganak PSA

British Gas	32.5 %
Agip	32.5 %
Texaco	20 %
Lukoil	15 %

It was assumed by most observers that participation of Russia's Gazprom would facilitate the use of Russia's nearby Orenburg gas processing plant. (Limits on acceptance of Kazak gas by Orenburg have been a principal reason for lower Kazak outputs in recent years). However, difficulties developed over the definition of Gazprom's investment responsibilities, as the other partners refused to recognise its spending on the field during Soviet times and carry its investment. Prices for processing at Orenburg reportedly rose significantly after Gazprom left the group, though as of November 1997 Orenburg continued to process most Karachaganak gas and condensate output.[27]

In May 1997 it was announced that a gas condensate refinery would be built on the Karachaganak site and financed by the partners in the project. The refinery reportedly will have an initial capacity of 6 Mt/year of output, which could be increased to 15 Mt/year. However, it is not clear whether this plant will also treat the gas, and eliminate the need to send gas to Orenburg.

Karachaganak gas is to be used primarily for Kazak internal needs. The partners have discussed building a pipeline from Aksai via Krasny Oktyabr to Akmola, as well as an export pipeline to China. Gas output in 1996 was about 4 Bcm. Annual gas output at Karachaganak is due to surpass 5 Bcm in 2001 and eventually reach 15 Bcm. A significant portion of early gas is to be re-injected in order to improve oil and condensate production.

Oil and condensate output in 1996 was about 4 Mt. Annual oil and condensate output from Karachaganak could reach 9 Mt by 2001, and is expected to eventually reach 13 Mt. Karachaganak partners BG and Agip have a combined right to 6 Mt of oil export capacity during the initial phase of the CPC pipeline. In addition, Lukoil has rights to 4 Mt of CPC capacity. Connecting pipelines to the CPC have yet to be built.

Uzen

The Uzen field tender for exclusive negotiating rights to form a JV with Uzenmunaigaz was won by China National Petroleum Company (CNPC) in August 1997. Recoverable reserves of Uzen exceed 200 Mt. The field produced some 2.8 Mt of oil and 1.68 Bcm of gas in 1996. With foreign investment the government hopes to increase oil production from Uzen to about 7 Mt per year. The project is expected to require an investment of US$1.2 billion. The World Bank has agreed to disburse a US$109 million loan for the project, which will probably go to the Kazak partner, Uzenmunaigaz. CNPC plans to invest US$1 billion during the first five years of operation.

The Temir blocks

Elf Aquitaine (France) signed the first production sharing contract in Kazakstan in April 1992 for a block near Temir in northwest Aktyubinsk province. It shared this project with Veba (Germany). In August 1997 Elf sold its interest to Shell. Under the new arrangement, Shell controls 60% of the project and Veba the remaining 40%.

27. Beginning in March 1995 the group began processing 3.5 - 4 Mt of condensate annually for sales to help finance work on the Karachaganak field. The condensate was stabilised and demercaptanised at Russia's nearby Orenburg refinery, owned by Gazprom subsidiary Orenburggazprom. It was then sent to the Ufa and Salavatnefteorgsintez refineries in Bashkortostan for further processing.

In October 1997 TPAO (Turkey) signed a US$750 million production sharing agreement for the exploration and production of a different onshore block near the Temir in the northwest Aktyubinsk region. (The Shell/Veba and TPAO/Amoco projects are separate, but are both somewhat confusingly referred to as the "Temir project".) The Kazaks have estimated recoverable oil reserves at 38 Mt. The PSA calls for an exploration period of four years, to be followed by an extension of 25 years, or to 40 years if more than 100 Mt of oil is discovered. TPAO reportedly paid the government US$3 million as a signing bonus, and a further US$2 million to the Akmola new capital fund. The government expects to earn US$1.8 billion in revenue over the life of the project. TPAO will form a 50/50 joint venture with Amoco, with which it had signed an earlier agreement outlining common interests. This is the first production venture in Kazakstan for Amoco, which will have 60 kb/d of capacity in the CPC pipeline.[28]

Other major joint ventures in the oil and gas sector

Other notable projects involving foreign firms include the following:

- *Japan JIT Oil JV,* with three Japanese partners led by Japan National Oil Corporation (JNOC), located northwest of the Aral Sea in Aktyubinsk province. In early 1997 the consortium signed an E&P deal and a 30-year PSA to produce any oil found. This followed an April 1994 exploration agreement between JNOC and the Kazak Ministry of Geology. Over the three years between the two agreements, JNOC reportedly spent over US$50 million and found several commercially viable fields. Total investment by the consortium is expected to be US$3.87 billion over 30 years.

- *Arman JV,* with foreign partner Oryx Energy and Kazak partners Mangystaumunaigaz and Zharkyn, located near Mertvy Kultuk. As of April 1996, Arman was producing 4,500 b/d, most of which it exported via the Druzhba pipeline to eastern Europe.

- *Kazakturkmunai JV,* with foreign partner TPAO (Turkey) and Kazak partner KazNIGRI, located in Aktyubinsk, Atyrau and Mangystau oblasts. The JV focuses on exploration, development and production of oil and gas. In 1996 the venture produced 24,500 tonnes (488 b/d), and was expected to produce 213,600 tonnes (4,272 b/d) in 1997. The venture area reportedly has reserves of 4 billion barrels of oil and 220 Bcm of gas.

- *Tenge JV,* with foreign partners Anglo-Dutch and Naphta Israel, located at Tenge oil field, bordering the Caspian Sea, 175 miles south of Tengiz. The venture produced only marginal amounts of oil in 1996 and planned to produce 147 kt (2.9 kb/d) in 1997. Expected production for 1999 is 36 kb/d. Estimated reserves are 500 million barrels of oil and 28 Bcm of gas. Expected investment is US$185 million.

28. The "Agreement on Principles of Co-operation Between Amoco and the Government of Kazakstan to 2011" includes provisions for participation in the former Munaigaz share of CPC, rights to the South Emba field in Atyrau province, and to the Temir field in Aktyubinsk province. It also mentions plans to lay an oil pipeline across the bottom of the Caspian Sea to Azerbaijan and then to Turkey, construction of small refineries and a network of filling stations. By 2011 Amoco reportedly plans to have invested US$1 billion in the Kazak oil industry.

- *Tulpar Munai JV,* with foreign partner Mobil (US) and Kazak partners Poisk Tulpar and Aktobemunai, located in the Tulpar region, in northwestern Kazakstan. As of mid-1996 it was producing a small amount of oil.

- *Utopia JV,* with foreign partners Union Texas Petroleum (US) and Oman Oil Co (OOC), located in Blocks A and E in Atyrau region, north of the Tengiz field. Reserves are estimated at 136 Mt. The expected investment size is US$75 million, with US$11 million budgeted for seismic studies and other operations in 1997, and US$20 million over the next 3 years. OOC was awarded the blocks in 1993, and sold 75% of its interest to Union Texas in 1997. Since OOC retains a small stake in CPC, the venture should be in a good position to export its product.

- *South Emba* field to which Amoco won exclusive negotiating rights in March 1997.

- *Baiganin block* in the Aktyubinsk region of northwestern Kazakstan, to which Repsol Exploracion (Spain) and Enterprise Oil (UK) won a 1993 tender for exclusive negotiations in 1993 to form an eventual PSA. As of the beginning of 1997 the two companies had already paid US$2 million in bonuses and for geological and geophysical information. They expect to spend another US$20 million on exploration. According to the two foreign partners, negotiations have dragged on since 1993 due to lack of adequate PSA legislation and lack of information on, and infrastructure at, the Baiganin fields.

Privatisation

Privatisation of the oil and gas industry began in 1996 as a way to increase efficiency in the sector and provide revenue to the government, both from the initial sales and from the increased tax revenue of the privatised companies. Prior to privatisation, state-owned oil and gas producers under the Munaigaz system contributed very little to the state budget.

The original plan of the government was to:

- allocate 10% of each company's shares to its workforce;

- sell a controlling share to a strategic investor so that the Kazak entity could be recapitalised and reorganised to maximise its value, and

- gradually sell the remaining shares on the local stock exchange as the value of the company increased.

Legislative basis

The Presidential Decree of 23 December 1995, "On Privatisation," established the basic legal principles, as well as the rules and procedures for privatising Kazak state-owned facilities. It envisaged both mass privatisation, and project-by-project privatisation. According to the decree, privatisation could be implemented only on the basis of competitive bidding.

A Programme of Restructuring and Privatisation for 1996-1998 was adopted to follow-up the earlier programmes of divestment and privatisation.

Privatisation in practice

Under the small-scale privatisation programme, oil product distribution was largely placed in private hands by the end of 1996. Privatisation of large-scale energy enterprises began in 1996 with sales of shares in several electric power stations, oil and gas production enterprises and refineries. Most sales were to foreign firms. Stating that foreign capital was the only way to halt decline in the sector, the government set itself an ambitious deadline of 1 July 1997 for privatising the oil and gas industry.

The groundwork for privatisation was prepared in 1995, when Kazakstan converted most of its oil and gas enterprises into joint stock companies. Rejecting the Russian path of forming large, state-owned, integrated oil and gas companies, Kazakstan opted instead for smaller, privatised firms substantially open to foreign investment. Mangistaumunaigaz, Tengizmunaigaz and Embamunaigaz were thought to be among the most attractive Kazak oil producers for private investors.[29]

In practice, Kazak companies did not always attract the high level interest hoped for by the government. Part of the problem was that the debts and obligations of Kazak companies were not always easy to quantify, particularly in the areas of social welfare and existing environmental degradation.

From the time the original plan was announced, many Kazak oil company managers voiced strong reservations, and oil workers expressed fears that privatisation could mean loss of jobs and benefits. Privatisation in the oil and gas sector was effectively sidelined during the early 1997 restructuring of the organisational bodies of the oil and gas industry. On 4 April 1997, Prime Minister Kazhegeldin issued an order to postpone a tender for the Embamunaigaz oil and gas production association and to delay the announcement of a tender for Tengizmunaigaz. These associations subsequently were taken over by Kazakoil, along with the Atyrau refinery, the tender result for which was voided in early April 1997. The result of the tender for exclusive negotiating rights for running the gas pipeline system was also voided in April, and the announcement of the result of the tender for the Uzen field was delayed. The government further stated at this time that tender winners would no longer receive exclusive negotiating rights.

During the government re-organisation in March 1997, the State Property Management Committee, responsible for carrying out privatisation, was disbanded. The main opposition to the policy of rapid privatisation came from the leadership of the former Ministry of the Oil and Gas Industry, which went on to head the new national oil company, Kazak Oil. The oil officials complained to President Nazarbayev that tender winners were not paying enough for state enterprises and investing too little.

29. Companies sold to private investors did not necessarily include those companies' interests in Jvs, ownership of which were to be transferred to the government under a special unit of Kazakoil. However, when Canada's Hurricane Hydrocarbons bought Yuzhneftegaz, it was also able to negotiate the purchase the latter's share in several JVs.

Privatisation strategy since April 1997 has become more cautious. Balgimbayev, at that time the head of newly created Kazakoil, announced that, "from now on we will have to check the bidders' creditability more thoroughly, define the minimum demands more precisely, and determine the future modernisation programmes with the winner in more detail."[30] Kazakoil officials called for tender winners to pay larger bonuses, to enact more immediate payment, to meet shorter and more strictly enforced deadlines for investment, and to bear more responsibility for the previous debts of purchased companies.

It appears that the size of shares being offered to foreign investors shrunk, from typically 90% for tenders prior to March 1997, to more commonly around 60% after. Nevertheless, by March 1997 over 60% of Kazak reserves had been transferred to private hands.

Although privatisation effectively had been halted by mid-1997, it was officially suspended in February 1998 while the government began a search for a "strategic partner" for Kazakoil.

Major privatisations

Major privatisations in the oil and gas sector include the following:

Yuzhneftegaz (Hurricane Kumkol Munai)

Canada's Hurricane Hydrocarbons won title to an 89.5% share in Yuzhneftegaz in 1996 in Kazakstan's first oil and gas company privatisation tender. (The remaining shares were given to the production association's employees when it was converted to a join stock company prior to privatisation.) Yuzhneftegaz produced 50 kb/d in 1996 and has estimated reserves of 581 million barrels. Its main field is Kumkol. Hurricane reportedly paid US$120 million for the association in four installments, the last of which was made in April 1997. (The purchase was financed by two stock offerings on the Toronto stock exchange.) Hurricane has plans to invest some US$280 million over five years in the joint stock company, which is now known as Hurricane Kumkol Munai. The government reportedly expects to earn royalties and taxes from the venture amounting to around US$280 million over the next 20 years. Hurricane ships all of its crude to the Shimkent refinery, though could export crude by pipeline to the Chardzhou refinery in Turkmenistan. It also has a 1998 Kazak government allocation of 100,000 tonnes of oil per quarter via Russia's Transneft system for export to the West. This can be achieved through swap arrangements with Russian or western Kazak producers or pipeline companies.

Aktobemunai (Aktyubinskneftegaz)

China National Petroleum Company (CNPC) won a tender for 60% of the Aktobemunai production association in June 1997. According to Kazak authorities, Aktobemunai has reserves of 1.4 billion barrels, and in 1996 produced around 50 kb/d. Assets of major interest are the Zhanazhol and Kenkiyak fields, with 860 Mb of reserves, and the Zhanazhol gas processing plant.

30. Russian Petroleum Investor, May 1997.

CNPC reportedly paid US$4.3 billion for its share in Aktobemunai, along with a promise to invest US$585 million between 1998 and 2003. Perhaps the most important component of CNPC's bid was its pledge to build a 3,000-km oil pipeline to western China, at an estimated cost of US$3.5 billion. (See Proposed oil export pipelines)

Karazhanbasmunai

In March 1997, Triton-Vuko Energy Group (US) won a 94.5% stake in the Karazhanbasmunai oil production association in Kazakstan's Mangistau region. Karazhanbasmunai has estimated recoverable reserves of 85 Mt, and in March 1997 produced 13.26 kb/d. Triton-Vuko reportedly was originally interested in forming a joint venture with Karazhanbasmunai, but was asked by the Kazak authorities to consider purchasing the association instead. Technological difficulties faced by the association include high paraffin and asphalt-tar content, and a complex geological structure.

Mangistaumunaigaz

Mangistaumunaigaz is Kazakstan's largest oil producer, after Tengizchevroil, with an output of 90 kb/d in 1996. The area to which the association has rights contains approximately 35% of Kazakstan's recoverable oil and gas reserves. Some 60% of Mangistaumunaigaz was offered for tender in late 1996, with the winner chosen in March 1997. The tender originally aroused strong opposition among the company's management, which tried to raise outside backing for a management buy-out.

The winner of the tender, Central Asian Petroleum (CAP), is a British Virgin Islands-based company owned by Indonesia's Medco Energi and Setdco Group and Japan's Mitsui. The reported price paid was US$228 million, plus a bonus of US$248 million. In addition, CAP promised to invest some US$4 billion over 20 years, including US$1.5 - 2 billion over the next five, of which US$30 million is to go to social infrastructure, US$70 million to protecting the environment, and US$19 million to training Mangistau personnel. CAP reportedly has also assumed US$100 million of Mangistaumunaigaz's debt. CAP has estimated that Kazakstan could earn some US$389.5 million over 5 years and US$1.68 billion over 20 years in budget revenues from its project, including royalties, income and excess profits tax.[31]

As of December 1997 the sale to CAP had not been finalised, reportedly due to a dispute over oil export quotas.

Stock exchange

The stock exchange was launched in late 1997, but as of the beginning of 1998 had seen little trading of shares. The first major floatation, which was to include government stakes in 13 large "blue chip" companies, was delayed until 1998, in part due to the upheaval in the international share market at the end of 1997. The government hopes to raise some 40 billion tenge from the

31. Interfax 4/4/97.

first round of sales, which are to include 5 - 7% of Mangistaumunaigaz and 5 - 15% of Aktobemunai. Government shares in the Pavlodar and Atyrau refineries are to be offered in a later round.

Management contracts

In 1994 the government introduced management contracts between foreign companies and Kazak state-owned “enterprises in difficulty”. Most contracts were in the non-ferrous metals sector. Under such arrangements the foreign contractor promised to redeem outstanding arrears to suppliers, workers and fiscal authorities, and was paid in shares and/or with profit participation. By early 1996, some 40 of the approximately 180 large state companies had been assigned by tender to foreign management consultancies. However, there has been some disappointment in this programme, as the incentive structure appeared to reward short-term profit maximisation over long-term consolidation of companies’ financial base.

Investment legislation

Investment legislation in Kazakstan has been issued both in the form of parliamentary laws and as Presidential decrees. According to the 1995 Constitution, parliamentary laws and Legislative Decrees of the President have equal legal power.

Law on Foreign Investments

The Law on Foreign Investments of 27 December 1994 supersedes the 1990 Law on Foreign Investments. It states that, in case of conflict between Kazak law and international treaties signed by Kazakstan, the latter takes precedence. In the event of changes in legislation detrimental to a foreign investor's situation, it allows foreign investments to operate under legislation prevailing at the moment the investment was made for a period of 10 years, or until the relevant contract with the state body expires. The law provides guarantees against expropriation, as well as against illegal actions of state bodies and officers. It also gives investors the right to take disputes that cannot be settled by negotiations to one of a list of international arbitration bodies.

Petroleum Act (licensing regime)

The legislative decrees, "On Subsoil and Subsoil Use" of 27 January 1996 (No 2828), and "On Oil" of 28 June 1995 (No 2350) establish a system of licences and contracts for allocating subsoil use. Licences for exploration and production of oil, gas and coal are issued by the government; on the basis of such a licence the competent body (as of September 1997, the State Committee for Investments) concludes a contract with the investor.

The Decree on Oil foresees three forms of ventures:

- joint ventures between local and foreign companies;
- production-sharing agreements (PSAs); and

- service agreements.

According to the Decree on Oil, there are two possibilities for obtaining a right to explore for and produce oil in Kazakstan:

- bidding (which may be competitive or restricted), and
- direct negotiations with the government.

The government has a right to choose the second option if there are fewer than two participants.The conditions for a competition must be published and include the competition procedures and timetable, a description of the blocks on offer and the minimum tax and other payments (rent, bonuses, royalties, etc.). Participants in a competition are required to pay a participation fee and a specified payment for a portfolio of geological and other technical information.

The Decree on Oil gives the licensee the rights to

- dispose of the product as the licensee wishes;
- construct necessary works;
- employ sub-contractors; and
- assign or surrender his licence rights.

The licensee is in turn obliged to

- work to international standards in terms of safety and environmental protection;
- provide information to the authorities about operations;
- protect historical and archaeological remains, restore the land, and not impede the extraction of other natural resources.

Under the Decrees on Oil and on Subsoil and Subsoil Use, the licensee is obliged during the contract to give preference to Kazak equipment, materials, products and services, provided they are competitive in terms of price, efficiency, technical standards, quality, and conditions of delivery. The licensee must also give preference to Kazak personnel in carrying out operations.

Contracts with the State Committee for Investments cover the details of these rights and obligations and also rights to use land. However, the relevant local authority provides the land for the licence operations (on the terms laid down in the licence) and exercises environmental controls and regulations protecting land, water resources, and archaeological and historical remains.

Taxation

Key elements of the tax legislation are set out in the 1995 Presidential Decree, "Concerning Taxes and other Obligatory Payments to the Budget". Under this decree, corporations are classified for tax purposes as either "resident" or "non-resident". A resident corporation is one established in accordance with Kazak legislation or having its place of management in Kazakstan. A non-resident taxpayer, which carries out business activities through a permanent representative office, pays income tax on income from kazak sources connected with the permanent establishment as though a resident of Kazakstan.

Tax rates in force at the commencement of a foreign investment project remain so throughout the project's life, unless the foreign investor and government agree to re-negotiate the terms.

As of October 1997, the rates for direct taxes were as follows:

- Income tax on corporations (30%), paid monthly on the basis of the financial results of the previous month. Branches are subject to an additional tax levied on profits after income tax;
- Withholding tax on dividends and interest (15%);
- Tax on insurance payments (5%);
- Royalty, income from services (including management services), consulting, rents, and other sources, except income received as wages (20%).

Indirect taxes include:

- VAT (20%), payable on turnover and imports; in the latter case the tax base includes any customs duties, tariffs and excises payable on import. A December 1995 amendment to the Tax Code exempts geological exploration and prospecting operations from VAT.
- Customs duties with rates varying according to the nature of the imported goods.
- Excise duties on certain goods, including crude oil, petrol and diesel, whether imported or domestically produced.
- Securities Transactions Taxes at rates of 0.5% of the nominal face value at the moment of registration of the initial issue, and 0.3% of their selling price in subsequent transactions.
- Annual Land Tax, depending on land quality and location and existence of water supply.
- Property Tax at 0.5% annually of the value of fixed commercial or industrial assets.

In addition, employers are obliged to pay 32% of payroll costs into various social security funds.

There are special payments and taxes for subsurface users. These include bonuses, which are one-off fixed payment for the right of geological exploration and/or subsequent mining. Bonuses are provided for in contracts concluded with the government, negotiated and agreed on a case by case basis with reference to published guidelines, and usually tax deductible. Bonuses include:

- Commercial discovery bonuses, which are fixed payments made in the case of discovery of new commercial reserves (usually not less than 0.05% of the value of the oil); and
- Exploitation bonuses, which are fixed payments at the moment of reaching certain conditions or stages of production (usually not less than 0.01% of the accumulated volume of oil).

Royalties are payable on production as stipulated by the relevant contract concluded between the user and the government. They are negotiated on a case by case basis.

Excess profit taxes are paid by subsurface users which earn higher than expected profits due to better conditions or prices. Excess profits tax payments begin when the internal rate of return of a project exceeds 20%.

Table 19 Excess profits tax

IRR range (%) above	through	Excess profit tax rate (%)
20	22	4
22	24	8
24	26	12
26	28	18
28	30	24
30		30

Source: Kazak Ministry of Finance.

From 1 July 1997 Kazakstan switched to an accrual only method of tax calculation. This has increased the effective tax burden on enterprises which are not able to collect their debts due to the country's ongoing non-payment crisis.

To prevent double taxation, credit is given for foreign income taxes against income tax payable in Kazakstan. Credit is limited to the amount of tax that would have been assessed on that income in Kazakstan.

Accounting system

According to the Presidential Decree of December 1996, " On Accounting", Kazakstan is to switch to Anglo-American accounting standards, in order to increase transparency and accountability for the benefit of investors. Large industrial enterprises were required to prepare their 1996 accounts on the basis of the new system.

TURKMENISTAN

Turkmenistan at a glance	
Land area	488,000 km^2
Population	4.5 million (1996)
Capital	Ashgabat
President	Sapurmurad Niyazov (also referred to as Turkmenbashi), since December 1991; referendum extended term until 2002.
Currency	US$ 1 = 4,165 manat at inter-bank auction rate (November 1997) US$ 1 = 5,300 manat at commercial rate (November 1997)
Real GDP growth	– 4% (1996)
Consumer price inflation	21% (1997)
Primary energy production	35 Mtoe (1996)
Energy consumption	14 Mtoe (1996)

SUMMARY

Reserves: Turkmenistan's petroleum resources are concentrated in gas, of which the country is thought to possess the largest reserves in Central Asia. Geological data are guarded closely by the government, and estimates of recoverable reserves are disputed, varying between 2.7 - 21 trillion cubic metres of gas and 1.5 - 47 billion barrels of oil, with government figures at the higher end of these ranges. Nevertheless, from a resource point of view, Turkmenistan could probably produce two, and possibly three times as much gas on a sustainable basis as the 38 Bcm it produced in 1996.

Production: Before the breakup of the Soviet Union, Turkmenistan was the world's fourth largest gas producer after Russia, the US and Canada. Annual gas production has declined from almost 90 Bcm in 1989 to about 33 Bcm in 1996, and 17.3 Bcm in 1997, due mainly to Russia's 1994 termination of an agreement giving Turkmenistan indirect access to European markets, and more recently to payment and access difficulties in FSU markets. Some of these difficulties are expected to ease in the short-to-medium term, others in the longer term.

Exports: Until 1994 Russia allowed Turkmenistan to ship 11 - 14 Bcm of gas per year to Europe via swap arrangements with Russian gas. Since then Russia has limited the transit of Turkmen gas to FSU markets, where Turkmenistan's largest customer has been Ukraine. However, most FSU customers have built up large payment arrears. Partly because of this, but also because of difficulties securing access through Russia after Turkmenistan dissolved a Russian-Turkmen joint marketing venture, exports of gas were suspended in March 1997. Some deliveries reportedly recommenced in late 1997.

Turkmenistan has tried to persuade foreign companies and lenders to invest in new gas export pipelines in order to break the country's dependence on Russia. The main routes being considered are: via Iran to Turkey (and eventually further to western Europe); via Afghanistan to Pakistan and India; and across the Caspian to Azerbaijan and Turkey. The first two projects appear to have run into difficulties due to sanctions involving projects in Iran, and lack of political stability in Afghanistan. At the same time, Turkmen leaders have been negotiating for a resumption of access to Gazprom pipelines to Europe. A small gas pipeline to supply power stations in northern Iran opened in December 1997; this was the first pipeline in the region to break Russia's monopoly on oil and gas export routes.

Future gas exports will depend on several factors, including development of solvent demand in other FSU republics, access to Gazprom pipelines, the development of alternative pipelines and transit schemes, and on Turkmenistan gaining shares in non-FSU export markets. Domestic demand in this sparsely populated country is not likely to significantly affect volumes available for exports for the foreseeable future.

Foreign investment: Compared to Azerbaijan and Kazakstan, Turkmenistan has seen relatively little foreign investment in its oil and gas sector. Some of the first foreign oil companies that entered into JVs with the government claim to have suffered from heavy-handed interference, including unilateral suspension of contract clauses. The government in its turn has charged that some foreign companies took advantage of Turkmenistan's inexperience in order to negotiate unduly favourable deals. Nevertheless, a number of other companies have felt confident enough to sign E&P agreements since then. Although many consider the investment framework for the petroleum sector to be inadequate, the new Law on Hydrocarbon Resources of March 1997 appears to be an important step in the right direction.

ECONOMIC BACKGROUND

The Republic of Turkmenistan is situated in the far southern portion of the former Soviet Union. It borders Kazakstan to the north, Uzbekistan to the north and east, Afghanistan and Iran to the south, and the Caspian Sea to the west. Approximately 90% of the country is desert, which helps account for the relatively low population of only 4.5 million.

In December 1991 the Communist Party of Turkmenistan dissolved itself, and the ruling Democratic Party of Turkmenistan was established. Power in the country is concentrated in the President. Mr. Sapurmurad Niyazov, a former Chairman of Turkmenistan's Supreme Soviet and First Secretary of its Communist party, is President of the country; his term has been extended to 2002.

The first years of transition

Prior to the breakup of the Soviet Union, roughly 8% of Turkmenistan's GDP was generated by gas exports to the rest of the USSR, mainly to Ukraine, Belarus and the Caucasus. Another 5% of GDP was earned from cotton exports. Gas and cotton exports continue to be used to cover the import of considerable amounts of grain and capital equipment from other former Soviet Republics. After 1991 Turkmen gas exports to FSU markets were rapidly crowded out by those from Russia, while total demand for gas imports by FSU republics declined rapidly.

Although estimates for the fall of GDP between 1990 and 1995 vary depending on how adjustments to official GDP are made, most western sources, including the IMF and EBRD, agree on about -35%. This is much less than the 58% drop in Turkmen gas production. The rest of the economy is basically agricultural. The cotton industry has been relatively less affected by the demise of the Soviet Union.

The government gradually liberalised some prices beginning in 1992. A presidential decree of 1995 removed price controls on all products except for about 50 items, including energy. The government introduced the manat as the national currency in 1993. In 1995 it unified the previously separate official and commercial exchange rates, which subsequently became determined by inter-bank auctions for foreign exchange.

Between 1992 and 1995 the government compensated for the shortfall in revenue from taxes on gas production and exports by cutting expenditures and replacing subsidies to the economy with additional allocations of credit at largely negative interest rates. The decline in real output and the resulting monetary overhang fuelled inflation at a rate of around 1,000% annually. Controlled prices were adjusted repeatedly but declined in real terms for natural gas and for oil products through 1994. The share of gas related revenues in the central budget declined from 60% in 1992 to under 20% in 1995, which lowered the share of total budgetary revenue in GDP from 40% to 10% during this period. Due to drastic expenditure cuts in government wages and investment, including maintenance, the central budget deficit remained fairly stable over this period. It also helped that new excise taxes were introduced in 1995 on petrol (55%) and diesel (60%). This resulted in some recovery of government capital spending.

The easy money policy was changed slowly in 1995 and 1996. During this time foreign exchange surrender requirements of state-owned enterprises to the Foreign Exchange Reserve Fund (FERF) were increased to 50% for gas and oil exports, and the money allocated directly to the central budget. Prior to that, this fund had been used to award credits to the economy, contributing to monetary expansion. In 1995 and 1996, bank credit allocation was reduced, real interest rates rose (due to credit auctions with deregulated interest rates), and reserve requirements for banks were increased. However, the pursuit of these policies was not smooth, in part due to the limited political autonomy of the Central Bank. Nevertheless, inflation decelerated by 50% towards the end of 1995 and is estimated to have been 445% in 1996, and 21% in 1997.

Despite plummeting gas exports in recent years, Turkmenistan's current account was slightly positive in 1994 and 1995, as long as arrears owed to the country are not taken into account. If such arrears are counted, the 1995 balance swings from an estimated surplus of US$54 million to a deficit of US$289 million. The situation has probably continued to deteriorate due to weak gas exports. Payment problems on the part of Turkmenistan's FSU gas customers have contributed to Turkmen arrears vis à vis the rest of the world, in particular with respect to servicing a US$58 million loan from the European Commission.

Indicators of physical production suggest that 1996 and 1997 did not bring the long awaited turn-around in the country's economic situation. Gas production remained low and fell significantly after a total cessation of exports in March 1997. Total industrial production in the first half of 1997 declined by 29%, with an accelerated decline in the second quarter.

In the face of these protracted problems, Turkmenistan's relationship with the IMF became more difficult. A standby credit agreement still had not been signed by the end of 1997. Turkmenistan remains the only Central Asian country never to have had an IMF-backed stabilisation programme.

Restructuring and privatisation

According to government estimates, officially registered private companies accounted for about 22% of employment and 9% of GDP in 1996. The entire private sector, including home industry and informal market trading, is estimated to account for about 18% of GDP. These shares primarily reflect the establishment of new enterprises rather than any significant changes in ownership to existing ones.

A privatisation law introduced in 1993 concentrates on small-scale enterprises in the services sector and does not appear to have been implemented with much vigour. Between the end of 1993 and the middle of 1996, some 1,800 small scale enterprises were auctioned off or leased to their employees. Shops and other enterprises providing consumer services typically are owned by regional and local authorities and municipalities. Privatisation targets and modalities and the pace of the privatisation process therefore usually have been decided at these levels rather than at the centre.

A significant share of Turkmenistan's agricultural land has been leased to private individuals, and private ownership of land plots up to 15 hectares has been legalised.

Among the approximately 90 large scale enterprises in the country (those with more than 500 employees), only four were partly privatised by 1997. The energy sector is explicitly excluded from privatisation.

According to government plans, the next phase of privatisation will concentrate on medium- and large-scale enterprises. A presidential decree of May 1994 warrants the preparation of a voucher privatisation scheme, though so far such a programme has not been implemented, and little preparatory restructuring of enterprises has taken place. Moreover, the banking system continues to extend credits to companies, and a Law on Bankruptcy, passed in 1992, has only rarely been invoked, if at all.

OVERVIEW OF THE ENERGY SECTOR

Turkmenistan depends on gas for about two thirds of its total primary energy supply (TPES), and on oil for the remainder. Fuel shares have not changed dramatically since the beginning of the 1990s, though there has been a slight increase in the share of oil at the expense of gas, in part due to declines in the gas industry's own fuel needs (since it takes significantly less energy to produce, compress and transport 35 Bcm than 90 Bcm), and declines in other industries' gas use. The shutting in of gas production capacity due to lack of export opportunities reportedly has imposed some technical constraints on deliveries to domestic consumers.

Turkmenistan's TPES declined by approximately 28% between 1990 and 1995. Meanwhile, GNP dropped by 35%, leading to an increase of about 10% in the country's energy intensity. Annual commercial energy use per capita in 1994 and 1995 was an estimated 3,100 kg of oil equivalent (kgoe), and energy consumption per unit of GDP an estimated 1.11 kgoe per 1993 US dollar.

Turkmenistan, like most FSU republics, consumes energy inefficiently, not only compared to more developed countries, but also to those at its own level of development. Turkmenistan is classified by the World Bank as a "lower-middle income" economy, but uses more than twice as much energy per capita as the average for that group.

Table 1 Comparisons of TPES per capita (1994/1995)

	Annual TPES/capita (kgoe)
Turkmenistan	3,100
Russia	4,500
Lower-middle income economies	1,540
High income economies	5,168

Source: IEA and World Bank World Development Report 1996

Fuel shares have not changed dramatically since the early 1990s and there seems little reason to expect major changes in the short to medium term. The share of electricity in final energy consumption is expected to increase, but the dominance of gas in power generation to remain. There are no nuclear power stations or plans to build any, and the climate of Turkmenistan does not favour hydro-electric power generation.

Electricity

The electricity sector accounts for approximately 35% of total gas use. Total installed generating capacity is 3.2 GW. Of the country's six major power stations, five are gas-fired. The sixth, which burns heavy fuel oil, accounts for only 0.4 % of capacity. The 1 680-MW Mary power plant burns some 1.5 Bcm of gas per year, accounting for almost half of the power sector's gas consumption.

Power plants buy gas from Turkmengaz at 6,000 manat per thousand cubic metres. This is same price paid by other industrial gas consumers, though significantly below the cost of gas production. Subsidised gas allows the Turkmen State Power-Technological Corporation (Kuvvat) to sell its electricity at extremely low prices to customers, reportedly without direct subsidies from the budget. All customers are charged one standard rate of approximately 1 US cent per kWh. Each household receives the first 35 kWh/month per person free of charge, though since there is little enforcement of payment for amounts above 35 kWh, all electricity to households is effectively free.

Turkmenistan has significant surplus generating capacity, which in 1996 was 40% above peak demand during the summer months. According to Kuvvat, most of the fall in electricity production in recent years has been due to decreased demand from oil and gas producers. In 1997 Turkmenistan generated around 9.2 billion kWh.

Despite surplus capacity, Kuvvat does not engage in significant electricity exports, due to payment problems in neighbouring FSU states. In 1997 it reportedly exported 1.5 billion kWh to Kazakstan, Tajikistan and Kyrgyzstan. Kuvvat is examining the possibility of exporting power to Iran and onward to Turkey, including as an alternative to gas exports. Kuvvat estimates that electricity would have to be sold at 2.5 - 2.73 US cents per kWh in order to be competitive with gas which Turkmenistan hopes to sell at US$42 per thousand cubic metres.[1] In the absence of sufficient gas export pipelines, such sales could have some use in generating hard currency. However, since gas inputs would presumably still be heavily subsidised, exporting electricity instead of gas could imply loss of value in the conversion.

ORGANISATION OF THE OIL AND GAS SECTOR

Between 1991 and 1993, the Turkmen petroleum industry consisted of a number of successor organisations to the Soviet institutions operating in Turkmenistan before independence. In 1993 President Niyazov issued a resolution placing these entities under the supervision of the Turkmen Ministry of Oil and Gas. This structure survived until July 1996, when an integrated Ministry of the Oil and Gas Industry and Mineral Resources was created and the former ministry's components were again transformed into nominally separate "concerns".

The Ministry of the Oil and Gas Industry and Mineral Resources is supposed to concentrate on overall energy strategy and analysis, with less day to day responsibility than the previous ministry for running the industry. In practice, it would appear that the new ministry continues to wield considerable managerial control.

Major organisations in the Turkmen oil and gas sector that report to the Ministry of the Oil and Gas Industry and Mineral Resources include the following:

- **Turkmenneft** is in charge of exploration, production and transport of oil and gas in the western portion of the country. (Western Turkmenistan is mostly oil producing, and the small amount of gas extracted is primarily associated.)

- **Turkmengaz** is responsible for exploration, production, processing and transportation of natural gas in the eastern part of the country. (Little oil is produced in eastern Turkmenistan.)

1. Presumably these are border prices inclusive of transmission within Turkmenistan.

- **Turkmenneftegaz** refines oil, markets oil products within the country and abroad, and markets gas abroad. It also manages gas distribution lines and maintains the Central Asia-Centre gas export pipeline, which is currently idle.

- **Turkmenneftegazstroi** builds and repairs internal oil and gas pipelines and gathering systems, while Turkmengaz and Turkmenneft take care of routine maintenance.

OIL RESERVES AND PRODUCTION

Two widely used sources on reserves, the BP Statistical Review and Petroconsultants, estimate Turkmenistan's proven oil reserves at 1.4 billion barrels and 0.98 billion barrels, respectively. A recent US Government report[2] estimates proven oil reserves at 1.5 billion barrels, with 32 billion barrels of additional reserves possible. The Turkmen government has estimated the country's proven oil reserves at about 47 billion barrels, including some 18 billion barrels offshore.

Turkmenistan owes the bulk of its oil reserves to the South Caspian basin. Discoveries have also been made in the Turkmen part of the Apsheron Sill.

The first oil wells in Turkmenistan were drilled in the western part of the country in 1911. Output peaked in 1970 at 16 Mt (320 kb/d), though by 1980 had declined to half that level. By 1990 annual oil production was only 5.7 Mt, and by 1995 it had declined another 40% to only 3.5 Mt.

The Turkmen oil industry is currently characterised by extremely low well productivity, the result of poor well-completion and reservoir management practices, and production beyond wells' economic limit. A World Bank study carried out in 1992-93 revealed that more than 50% of active wells did not appear to justify expenditure on routine maintenance operations.

Given current reserves-to-production (r/p) ratios, Turkmenistan's estimated oil reserves could conceivably support an output several times the present level. Even assuming a reserves estimate of 1.4 billion barrels, the country's r/p ratio would be 55 years. Observers generally consider an r/p in the 10-20 years range as indicative of efficient resource utilisation. To be in that range, Turkmenistan should be producing 10-20 Mt per year.

The government has an ambition of increasing production to 10 Mt by the turn of the century. Given investment constraints, it is unlikely they will manage this. However, an increase to some 8 Mt by 2010 appears within the realm of possibility. This would consolidate the country's position as a minor oil exporter.

PlanEcon estimates that crude oil and condensate production will at best increase to 5.3 Mt by 2010.[3] Some foreign oil companies active in Turkmenistan have more optimistic views, considering 10 Mt by 2010 a reasonable target.

2. Report to Congress on Caspian Region Energy Development, US Government, 1997.
3. PlanEcon, September 1997.

OIL REFINING

Oil refining is the responsibility of Turkmenneftegaz, which also markets products within the country and abroad. Most crude oil produced domestically, as well as some imported from Uzbekistan, is processed at Turkmenistan's two refineries, Seidi and Turkmenbashi. Each has a nominal throughput capacity of 6 Mt (120 kb/d), though combined actual capacity may have fallen to 8.5 Mt per year (170 kb/d) by 1997.

The older Seidi (formerly Chardzhou) refinery, located at Chardzhou in the central-eastern part of the country, traditionally has processed domestic crude. The newer Turkmenbashi (formerly Krasnovodsk) refinery on the Caspian Sea coast, was built to process Russian crude with a view to exporting the output. However, in recent years the Turkmenbashi refinery usually has operated on domestic crude, while Seidi has run only small amounts of imported Uzbek crude and condensate. Throughput in 1996 was 0.6 Mt at Seidi and 4.2 Mt at Turkmenbashi, plus an additional 0.2 Mt refined for a fee for various customers.

Although Turkmenbashi is the newest and most modern of the two refineries, the share of light products in its output is low by western standards. In 1996 its output by volume consisted of approximately 52% heavy fuel oil, 28% diesel, 10% petrol and 10% kerosene. To adapt the Turkmenbashi refinery to anticipated changes in product demand, the Government is earmarking US$1 billion to bring annual throughput capacity to 9 Mt by the turn of the century, add a hydro and catalytic reforming unit, a catalytic cracker and a lubricants plant. Mannesmann KTI (Germany) is helping construct a lubricants and aromatics unit, while Technip (France) is to construct a catalytic cracker.

In the years ahead Turkmenistan plans to refine crude from other Central Asian states. A Turkmen-Uzbek agreement stipulates transport of 0.57 Mt of Uzbek oil per year from the Kokdumalak field across the border for refining at Seidi, with the products to be marketed throughout Central Asia. There reportedly are also discussions between Seidi and Kazak producers. Given the ambitious refinery expansion plans of most of the other countries in the region, it is unclear whether there will be a substantial market for Turkmen oil product exports in the medium term.

OIL TRANSPORTATION AND TRADE

Turkmenistan ships small amounts of refined products to other FSU states and somewhat larger volumes of crude and products by ship to Iran.

Turkmenistan has only a small network of crude oil pipelines, mostly in the western part of the country. The main system stretches around Krasnovodsk Bay, with the Turkmenbashi refinery at the end of the northern leg and the Cheleken tanker terminal at the end of the southern one. Pipelines connect these facilities with fields east of the Cheleken peninsula, including the Kumdag, Nebit-Dag, Barsa Gel'mes, Kotur-Tepe and Cheleken fields.

Table 2 Turkmen crude oil and refined product exports by destination, 1996

Importers	Crude oil (Mt)	Refined products (Mt)
Kyrgyzstan	0.3	
Tajikistan	0.2	
Others (mostly Iran)	0.5	1.0
Total	0.5	1.5

Source: PlanEcon

The Southern leg of the oil pipeline system in western Turkmenistan extends some 30 - 40 km into the Caspian Sea to transport crude from the off-shore Pricheleken and Banka Zhdanova fields. Pipeline diameters range from 300 - 510 mm. The total capacity of the pipelines carrying crude to the Turkmenbashi refinery is around 200 kb/d.

Further south on the Caspian coast is a pipeline moving crude from the Kamyshldzha and Ekarem fields to a tanker terminal. Finally, the Chardzhou refinery, which is located close to the Turkmen-Uzbek border in central-eastern Turkmenistan, is at the end of a pipeline that originates in Siberia and passes through Kazakstan and Uzbekistan.

Refined products are transported by rail from the two refineries to Ashgabat and other consumption centres in the south of the country, or exported by rail or ship.

Proposed oil export pipeline via Afghanistan

Unocal (US) and Delta (Saudi Arabia) have proposed a crude oil export pipeline from Turkmenistan, via Afghanistan, to a terminal on Pakistan's Arabian Sea coast. Such a line could bring Central Asian, Russian and Azeri crude to rapidly growing South and East Asian oil markets. The two companies are also planning a gas export pipeline from the Dauletabad gas field in south-western Turkmenistan to Pakistan (see below). They see significant potential for synergy between the two projects, including a common right-of-way for part of the route. Construction of the oil pipeline is seen as following that of the gas line; by early 1998 it appeared that the latter would be delayed indefinitely due to problems in Afghanistan.

The oil pipeline is to originate at Chardzhou in eastern Turkmenistan, enter Afghanistan north of Herat, continue south along (but some 100 - 200 km away from) the Iranian-Afghan border, and finally run across Baluchistan and southwestern Pakistan to the Arabian Sea coast. It would have a total length of 1,670 km, about 700 km of which would cross Afghanistan.[4] The pipeline would have a total of eight pumping stations, giving a capacity of approximately 1 Mb/d per day. Total investment costs for the pipeline are estimated at US$2.7 billion, and annual operating costs at US$130 million. In addition, the companies intend to build a terminal in Pakistan with port facilities to receive tankers of up to 300,000 dwt, storage capacity of 10 Mb and two single point mooring systems.

4. The distance from Chardzhou to the Turkmen-Afghan border is about 460 km and that from the Afghan-Pakistani border to the Arabian Sea coast about 510 km.

Unocal and Delta see the project as serving the export needs of a number of countries in the region, including Russia. Several Russian oil producers, as well as Kazakstan's Hurricane Kumkol Munai, would have access to the new pipeline from the start. Chardzhou, the proposed starting point, is also the terminus of a pipeline carrying Russian crude to the Seidi refinery in Turkmenistan, along the way serving the Pavlodar and Shimkent refineries in Kazakstan. Turkmen and Uzbek fields in the vicinity of Chardzou reportedly could be linked to the new pipeline as well. (Some feeder lines are already partly in place.) Tengiz, Kenkyak and other fields in western Kazakstan, as well as fields in western Turkmenistan and possibly some off-shore Azerbaijan, could be connected at a later stage. Unocal and Delta estimate that a connection with the capacity to move 500 kb/d from Tengiz to Chardzou would cost US$0.5 - 1 billion, while a sub-sea line across the Caspian from Azerbaijan's off-shore fields to Chardzou would cost an additional US$1.8 billion.

Whether or when an Afghan authority will emerge with powers to sign long-term agreements and provide credible guarantees for operational safety is an open question. Unocal and Delta report that leaders of all the major religious, ethnic and regional groupings in Afghanistan support the project and have encouraged them to proceed as quickly as possible to the implementation stage. Currently, the fundamentalist Taleban movement controls all of western Afghanistan through which both the oil and gas pipelines would run.

GAS RESERVES AND PRODUCTION

Most of Turkmenistan's gas reserves are located in the Amu Darya basin in the central and eastern parts of the country.

Various outside sources estimate Turkmenistan's gas reserves at 2.7 - 4.4 trillion cubic metres (Tcm). To provide some perspective, 4.35 Tcm represents about 8% of estimated total FSU reserves, less than a quarter of estimated Iranian reserves, and 15 - 20 % above proven reserves for North America. At the lower end of the range are Russian estimates based on the last official Soviet evaluation of reserves in 1988. Russian geologists in VNIIgaz, a subsidiary of Gazprom, put remaining Turkmen gas reserves at 7.8 Tcm, less than 2.7 Tcm of which they classify as proven. Estimates by Turkmen authorities, at 15-21 Tcm, are significantly higher than those by most outside observers.

Gas was discovered in Turkmenistan in 1951. Production peaked at almost 90 Bcm in 1989, declined slowly through 1991, and dipped by 30 % in 1992, mainly due to falling solvent demand other FSU states and consequent problems regarding arrears and payment. Production began to recover in 1993, but plunged to 36 Bcm in 1995 and 33 Bcm in 1996, due to Russia's cancellation of a swap agreement in 1993 whereby Turkmenistan was credited for a share of gas exports to Europe related to its deliveries of gas to the FSU. (The annual Turkmen export credit to Europe typically ranged between 11 - 14 Bcm.) Production in 1997 was only 17.3 Bcm after the halt of exports in March 1997.

According to Turkmen authorities, current annual production capacity, assuming no export constraints, is 60 - 80 Bcm. Chronically short of funds, the gas industry has found it difficult to maintain fields and pipelines, not to mention carry out exploration and develop new fields. Turkmenistan's available gas production and export capacity therefore probably has declined.

Major gas fields

The largest gas field in Turkmenistan is the giant Dauletabad-Donmez field near Seraks on the Turkmen-Iranian border. Discovered in 1974, its reserves were initially put at 1,360 Bcm, though it is now assumed to be almost three times larger. In 1982 what was believed to be another giant field containing more than 2,000 Bcm of gas was discovered 24 km south of Dauletabad-Donmez and named Sovietabad. Soviet geologists later realised that the two fields were in fact parts of the same structure. Some 80% of Dauletabad-Donmez's recoverable reserves remains to be produced. This field figures prominently in Turkmenistan's ambitions to export gas not only to Europe, Pakistan and India, but also to China and Japan.

The Soviet engineers originally put in charge of developing Dauletabad-Donmez ran into numerous problems related to its complex geological structure, high formation pressure and gas characterised by high contents of sulphur, CO^2 and wax. Drilling programmes fell behind schedule and there were also delays in commissioning gas treatment plants. The northern end of the structure came on stream in 1983 and the southern end (Sovietabad) in 1984. Output quickly became significant, but has not increased at the envisaged pace. Since 1992 Turkmen authorities do not appear to have had either incentive (i.e., markets) or funds to further develop the field.

Future production from Dauletabad is difficult to forecast, since it depends on market and other developments. If and when output can be increased to the level seen as possible in the light of estimated reserves (one source, PetroStudies, estimates that it could yield 100-120 Bcm/year) Dauletabad could contribute significantly to several importing countries' supply.

Another important Turkmen gas field is Shatlyk, which once accounted for half of Turkmenistan's gas output. Despite going into decline in 1983, Shatlyk remains an important producer and the location of a key pipeline junction. Other important fields include the Malay, Saman Tepe, Naip, Kirpichili and Achak in eastern Turkmenistan, and the Ekizak gas field and Kotur Tepe and Korpedzhe oil and gas condensate fields in the west. Construction of a gas processing plant with a capacity of 4 Bcm per year to serve the Saman Tepe and nearby fields in the Amu Darya valley is on the government's list of priority projects.

Gas production costs and prices

In a recent report, the Word Bank put gas production costs in Turkmenistan at about US$18 per thousand cubic metres (presumably this refers to average costs, with marginal costs probably higher). Official Turkmen estimates for the average cost of extracting gas and bringing it to transmission lines is US$20 - 35 per thousand cubic metres.

According to Turkmengaz, power plants and industry were charged only 6,000 manat (around US$1) per thousand cubic metres in 1997. The government provides gas to residential end-users free of charge.

Gas consumption

Annual gas consumption within Turkmenistan is some 10 Bcm. The electricity sector accounts for some 35% of this, industry and other sectors 55%, and the gas industry 5 - 10%, depending on production levels.

Of the country's six major power stations, five are gas fired. The Mary nitrogenous fertiliser plant, which was put into production in the mid-1980s, accounts for a high share of industrial gas demand. The chemicals factory in Chardzhou, the Karakum and Pustyannya compressor stations, and households in Ashgabat are the other major consumers. Households in many outlying regions of Turkmenistan are also gasified.

GAS TRANSMISSION AND DISTRIBUTION

Turkmenistan has 7,330 km of gas transmission pipelines, accounting for some 3% of the FSU grid. The country operates two separate gas pipeline systems, one in the East and the other in the West.

The starting point of the eastern system is the Shatlyk gas field east of Tedzhen. From Shatlyk a 530-mm line runs westward to Bezmein, supplying a number of cities along the way, including Tedzhen, Merv, Bairam-Ali and Ashgabat. Another line runs eastward to the large Mary gas-fired power plant.

Shatlyk is also on a south-north line carrying gas from the Dauletabad-Donmez field near the Turkmen-Afghan border, from Shatlyk itself and from other fields northward to Khiva. This key pipeline system also transports Uzbek and Turkmen gas north-westward along the Amu Darya river to the Kungrad compressor station in Uzbekistan. From Kungrad, most of the gas continues via Kazakstan to Alexandrov Gay in Russia, while some is sent northward on two aging pipelines to Chelyabinsk in the Russian Urals region. The Dauletabad-Shatlyk-Khiva system, which accounts for the bulk of Turkmenistan's gas exports, is fairly new. In 1976 two parallel lines were laid between Shatlyk and Khiva. In 1985 a new line was built from Dauletabad to Alexandrov Gay in Russia. And in 1986-88 the Dauletabad-Khiva line was looped by a 1,420-mm line.

The pipeline system in western Turkmenistan is older than the one in the eastern part of the country. It originates at Ekarem, near the Turkmen-Iranian border. Running northward, it provides an outlet for associated gas from fields scattered along the Caspian coast between Okarem and Nebit Dag. It continues via the narrow strip of land separating the Kara-Bogaz Gol from the Caspian Sea, enters Kazakstan and continues via Uzen to the Beyneu compressor station in north-western Kazakstan, where it meets the Khiva-Alexandrov Gay system outlined above.

South of Cheleken, the western system consists of only one 710-mm pipeline, though between Cheleken and Beyneau there are two parallel lines with a diameter of 1,220 mm. This system serves consumers in western Turkmenistan and Kazakstan and carries exports. However, in recent years the share of output left for exports from this part of the country has declined in step with oil production. Consequently, the Ekarem-Beyneau pipeline, particularly its northernmost segment, is severely underutilised.

At Makat, some 150 km from Atyrau on the Kazak Caspian Sea coast, a 1,020-mm line branches off the Ekarem-Beyneau system, heads south-eastward to Atyrau and continues along the north coast of the Caspian Sea via Astrakhan, Kalmykia and Dagestan in Russia to link up with the North Caucasian pipeline network. From Alexandrov Gay some central Asian gas is directed eastward on the Soyuz export pipeline system, while the rest continues northward to Saratov and Moscow. The pipelines from Gazli to Makat have an annual design capacity of 63 Bcm; the system onward to Alexandrov Gay, 35 Bcm; and the line between Makat and the Transcaucasia, 28 Bcm. However, actual capacities are usually below design, and in some cases far below.

Turkmen authorities claim export pipeline capacity of 60 - 80 Bcm. However, Turkmenistan's export pipelines, all of which pass through Uzbekistan and Kazakstan, are reportedly in a precarious state. Since the break-up of the Soviet Union, the cessation of central funding and the emigration of skilled pipeline crews, these pipelines have reportedly seen little maintenance. Long stretches are badly corroded and reportedly risk cracking if operated at their design pressure of 75 bars. In recent years they have been utilised at less than half their nameplate capacities. If further export opportunities materialise and the utilisation of pipelines increases, technical transit breakdowns could become a problem.

In awarding contracts for upgrading the country's gas infrastructure, Turkmengaz gives priority to those companies willing to take payment in gas. Given limited export possibilities and internal gas prices controlled at levels below production costs, this effectively limits competition to companies from the region. Some Ukrainian crews have worked in Turkmenistan as part of previous payment arrangements for Turkmen gas sent via Russia.

New gas export pipeline projects

Gas pipeline to northern Iran

In December 1997 an affiliate of the National Iranian Oil Company (NIOC) completed construction of a 200-km, 12-Bcm/year pipeline from Korpedzhe, Turkmenistan, to Kurt-Kui in north-eastern Iran. Initially it is to carry 2 - 4 Bcm per year of Turkmen gas to the Neka power stations in northern Iran. Annual deliveries early in the next century are forecasted to reach 10 Bcm. Construction costs were reportedly US$190 million, financed mainly by Iran. Ashgabat will see little immediate revenue for its gas deliveries since it is to pay for 90% the portion constructed on Turkmen territory in gas deliveries over three years, with the balance in cash.

There are also plans to link this line to possible future gas deliveries to Turkey. In Kurt-Kui the pipeline could connect with an existing east-west transmission pipeline running from Khangiran field to Tabriz in north-west Iran, and from there to a pipeline that could be built to Turkey.

Turkmenistan-Iran-Turkey

The Turkmen government has for a number of years promoted the construction of a gas export pipeline to Turkey. Although the government has entertained various routes, including a trans-Caspian one (see below), it has given most attention to routes crossing Iran.

In 1997 Royal Dutch/Shell received the exclusive right from the Turkmen government to build and operate a pipeline to Turkey via Iran; in December 1997 it received authorisation from the Turkmen, Iranian and Turkish governments to form a pipeline consortium and investigate sources of finance.[5]

A preliminary feasibility study for variations on an Iranian route was completed for the Turkmen government by Sofregaz (France) in late 1997. All options studied by Sofregaz go from the Shatlyk field, which has remaining extractable reserves estimated at 460 Bcm, to Karadeniz, just over the Turkmen border in Iran. From there a northern variation runs along the coast of the Caspian Sea, while a longer southern option goes via Tehran. Shell, which began a detailed feasibility study in 1998, is also reportedly considering a shallow water pipeline under the Caspian Sea.

Whatever the final route, it may prove economic to carry out the project in two stages. Initially, a system with a capacity of 15 Bcm per year could be built to supply the growing Turkish market. In time, capacity could be increased to 28 - 30 Bcm per year with a view to supplying markets further west.

Preliminary assessments of the costs of putting the system in place are between US$1.62 - 2.75 billion. Increasing the capacity to 28 Bcm a year, which would primarily entail adding another five compressor stations, could require an estimated additional US$1 billion.

A major problem for the project is that firms are reluctant to commit large sums to schemes involving Iran, due to possible sanctions by the United States, which is concerned about Iranian state-supported terrorism. Mobilising equity has been difficult too, as both the Turkmen and Iranian economies are currently facing difficulties.

In July 1997, the US government seemed to indicate that a gas pipeline from Turkmenistan to Turkey via Iran would not contravene US sanctions legislation. The US later clarified that, as a matter of policy, it opposed the construction of pipelines across Iran and would examine any pipeline projects for possible implications under its sanctions legislation. Most observers feel that it would be difficult to arrange the project so it does not run afoul of US sanctions legislation.

Besides the threat of sanctions, other potential difficulties for foreign investors include the fact that, under current Iranian law, any pipelines on Iranian territory, as well as any tariffs accruing from them, would be the sole property of Iran.

There is also some uncertainty regarding the amount of Turkmen gas Turkey actually could absorb, given the aggressive marketing efforts of Gazprom and other potential suppliers. Annual sales volumes will influence the time period needed by foreign investors to recoup their investments.

5. A potential difficulty with Shell is its strategic alliance with Gazprom (also agreed in late 1997), since Gazprom is a chief competitor of Turkmenistan in selling gas to Turkey.

Evolution of Turkmen plans for foreign participation in a gas pipeline to Turkey

The concept of the project has undergone a number of changes, especially in regard to the scope of foreign participation. In late 1993 Turkmenistan hired a foreign firm to organise a consortium of private companies to build and operate the prospective line. At the same time President Niyazov formed an inter-state Council of Ministers to direct the activities of the consortium. This concept survived until late 1994 when the Turkmen government decided that it, and not private interests, should own the pipeline. The government duly formed a new joint stock company, Turkmenistan Transcontinental Gas Pipeline (TTGP), to plan, finance, construct and operate the line. Under this variation, foreign investors only would have been able to receive profits in the form of dividends. The concept underwent another change in 1997, when, faced with increasing financial difficulties, the government entertained the possibility of widening foreign ownership of both the pipeline and the gas within it. Previously it had insisted that the gas should remain Turkmen property. The government now seems amenable to selling gas at the Turkmen border.

Trans-Caspian

Oil Capital (US) and Botas (Turkey) have proposed a gas pipeline across the Caspian Sea from Turkmenbashi (formerly Krasnovodsk) to Azerbaijan and onward to Georgia and Turkey. The project would make use of an existing 720-mm gas pipeline originating at the Neft Dashlary field off-shore Azerbaijan that runs via Baku and Kazi Magomed to the Azeri-Georgian border and onward via Tbilisi to Kutaisi in western Georgia. From there it would be necessary to construct a new 300-km pipeline to the Georgian-Turkish border and onward to Trabzom on the Turkish Black Sea coast. The proposed gas line could run parallel to AIOC's "early oil" pipeline terminating at Supsa, holding out possibilities for common use of installations and reduced costs. Other companies are also reportedly interested in such a pipeline.

The Turkmen government has not given full endorsement to this scheme, citing higher costs compared to a route via Iran, political uncertainties in the Caucasus and problems related to the unsettled legal status of the Caspian Sea.

Via Russia to Turkey

In 1996, President Niyazov signed a memorandum of understanding with then Turkish President Demirel under which Turkmenistan is to export to Turkey 2 Bcm per year in 1998, 5 Bcm per year between 1999 and 2004, 10 Bcm per year between 2005 and 2009, and 15 Bcm per year between 2010 and 2020. Initially these exports were to go via existing pipelines running through Kazakstan, Russia and Georgia to Armenia, from whence a short pipeline would have to be built to Turkey. The lack of a transit arrangement with Russia makes scheduled deliveries highly unlikely in 1998. As a longer term solution, this route suffers from the fact that Gazprom also plans to enter the Balkans through the Caucasus and will be competing with Turkmenistan in the Turkish market.

Turkmenistan-Pakistan gas pipeline projects

In August 1993, President Niyazov and Pakistan's then Prime Minister Bhutto signed a memorandum of understanding on building a gas pipeline with a capacity of 20 Bcm per year from Turkmenistan to Pakistan via Afghanistan.

At first it appeared that Bridas (Argentina), which was already developing several Turkmen oil fields, would lead the project. The Turkmen Government also invited Gazprom to join the project, as well as the Indian government, holding out the possibility of extending the line to northern Indian markets.

The proposed pipeline, with a diameter of 510 mm, was to begin at Yashlar, a large Turkmen gas field with reserves of up to 800 Bcm and slated for development by Bridas. It was to run via western Afghanistan to Chaman on the Afghan-Pakistani border, to the provincial capital of Quetta and finally to Baluchistan in western Pakistan, where that country's main gas fields are located. There it was to link up with Pakistani gas trunk pipelines. The length of the line was to be around 1,400 km, with construction costs estimated at US$3 billion.

By late 1995, the Bridas project lost the favour of the Turkmen government, in part due to protracted difficulties between Ashgabat and Bridas over that company's oil field investments in Turkmenistan.

In October 1995, the Turkmen government signed an agreement with a consortium of Unocal (US) and Delta Oil Company (Saudi Arabia) to build and operate a 1,300-km pipeline from Turkmenistan's Dauletabad field to Multan in northern Pakistan. The line's capacity and route were to be similar to those of the planned Bridas line, though with construction costs estimated at US$1.9 billion, and an extension to northern India an additional US$600 million. The main innovation of the Unocal-Delta consortium was its proposal to take delivery of 20 Bcm per year at the Turkmen-Afghan border and market it at its own risk. (Unocal and Delta also proposed to construct an oil pipeline along a similar route, though to Pakistan's Arabian Sea coast, and to build and operate a number of gas-fired power plants in Pakistan.)

In October 1997 the Turkmen government signed an agreement with Unocal and other parties to form the Central Asia Gas Pipeline Consortium (CentGas). The initial division of shares gave Unocal 46.5%, Delta 15%, the Turkmen government 7%, Indonesia Petroleum (Japan) 6.5%, Itochu (Japan) 6.5%, Hyundai (South Korea) 5%, Crescent Group (Pakistan) 3.5%, with 10% reserved for Russia's Gazprom.

As indicated earlier, the biggest problems for pipeline projects involving Afghanistan are the security threat posed by the country's warring factions and the lack of an internationally recognised government. The latter is seen as a necessary precondition for securing finance. The Unocal/Delta consortium claims it is prepared to wait for conditions to stabilise in Afghanistan. It also reports that it has signed a memorandum of understanding with the Taleban movement, which by early 1997 had for some time been in control of the part of western Afghanistan through which the pipeline would pass.

Another problem raised by some analysts is that it may be difficult economically to justify a gas pipeline based on Pakistani demand alone, and that an extension to India may therefore be necessary. However, such an extension would be fraught with political difficulties between India and Pakistan.

The recent discovery of a large gas field in Pakistan's southern Sindh province could also undermine Pakistani demand for imported gas.

Meanwhile, Bridas opened an office in Kabul in 1997 and has taken Unocal to court for interference in its plan to export Yashlar gas to Pakistan. It also filed complaints against the Turkmen Government with the International Chamber of Commerce for illegal interference in oil exports from a Bridas-operated joint venture in Turkmenistan.

Turkmenistan-China-Japan gas pipeline project

In April 1994, Turkmenistan and China signed a protocol of intent to build a gas pipeline from Central Asia to the east coast of China and onward to Japan. According to Turkmen authorities, the Mitsubishi Corporation, the Chinese National Petroleum Corporation (CNPC) and other firms have been interested in the project. In 1995, Exxon joined them to carry out a feasibility study. The US company is developing fields in the Chinese Xinjiang province, through which the line could pass.

The pipeline would probably start at the Turkmen-Uzbek border near Khiva and traverse Uzbekistan and Kazakstan, whose governments are favourable toward the project, before skirting China's Tarim basin on its way to the Yellow Sea. Thus there would be possibilities to move Chinese gas as well. At least 16 compressor stations would be needed along the 6,500-km route to move 28 - 30 Bcm of gas per year to the coast.

For possible transport onward to Japan, one option would be to build a liquefaction plant at Lianyungang on the East China Sea. LNG tankers could shuttle between this facility and a re-gasification plant on the Japanese side. Another option would be to extend the pipeline some 900 km across the sea and land the gas in the vicinity of Nagasaki on the island of Kyushu.

The whole system would take at least 4 - 5 years to build. Costs very preliminarily have been put at about US$12 billion, which would pay for a 1,440-mm pipeline, compressor stations to provide an annual capacity of 30 Bcm, and a liquefaction plant with an annual capacity of 10 Mt.[6]

The main problems with a Turkmenistan-China-Japan project are the size of the task, the level of costs, the political, legal and other complexities of involving several transit countries, and uncertainties involved in forecasting the competitiveness of Turkmen gas in east Asian markets at least 4 - 5 years into the future. A further question is whether Turkmenistan's gas reserves would be able to supply enough gas to amortise the project, especially in light of Ashgabat's simultaneous negotiations for other major export pipelines. Many observers see Central Asian

6. More recently, Turkmen authorities have put costs at US$9.5 billion, though presumably this refers only to the pipeline and compressor stations, and does not include envisaged liquefaction facilities.

gas exports across China as an option for the second or third decade of the next century. Judging by the relatively low intensity with which the Turkmen authorities are promoting this project, they appear to be operating with a similar time perspective.

GAS TRADE

Annual gas exports from Turkmenistan reached a peak of some 70 Bcm in the late 1980s. By 1994, annual exports had declined to 22 Bcm after Gazprom cut Turkmenistan's access to the European market and lower demand and payment problems led Turkmenistan to curtail shipments to FSU markets. Payment arrears among remaining FSU customers and difficulties securing transit through Russia led the country to cease gas exports in March 1997, although there are reports of limited deliveries resuming in late 1997.

Until late 1993 Russia allowed Turkmenistan to ship 11 - 14 Bcm of gas per year through Gazprom pipelines to Europe on the basis of swaps with Russian gas. In late 1996 Gazprom reportedly promised to revive the access agreement, though subsequent statements indicated it would only consider allowing Turkmen gas to compete for incremental demand in eastern Europe.

Since 1994 Russia has effectively limited the transit of Turkmen gas to FSU markets, most of which have continued to shrink and face payment difficulties. Ukraine has been Turkmenistan's largest customer, taking 12 - 16 Bcm of gas annually. Other customers include Armenia and Georgia, as well as Russia. Most gas transported to these markets has been on the basis of swaps for Russian gas.

Table 3 Turkmen gas exports by destination, 1995 and 1996 (Bcm)

Importers	1995	1996
Russia	0.3	
Ukraine	12.7	19.0
Armenia	2.2	1.0
Azerbaijan	1.0	
Georgia	1.5	
Kazakhstan	4.7	4.1
Kyrgyzstan	1.6	0.2
Tajikistan	0.2	0.2
Total	24.2	24.5

Source: PlanEcon, Inc.

Turkmen exports to Ukraine have to some extent been encouraged by Gazprom, which has wanted to reduce its own exposure to non-payment problems in the Ukrainian market. (See chapter, Markets for Caspian region gas.) In 1995 the Turkmen and Russian governments set up the trading company Turkmenrosgaz to market Turkmen gas in the FSU, especially Ukraine.

A private company, Itera, was also involved.[7] Turkmenrosgaz bought Turkmen gas at the Turkmen-Uzbek border and resold it to Ukraine and other customers. It handled transportation and was responsible for collecting payments. However, by the beginning of 1997 Ukrainian arrears for gas totalled over US$780 million, including US$200 million since the formation of Turkmenrosgaz.

Turkmen President Niyazov unilaterally dissolved Turkmenrosgaz in early 1997, arguing that it had not lived up to expectations. Following subsequent difficulties with Russia over transit, all exports of Turkmen gas were halted in March 1997, leaving total gas exports for that year at only 12 Bcm, well below the 40 Bcm the government had originally forecasted.

Subsequent talks in late 1997 between Ashgabat and Kiev reportedly resulted in a limited resumption of exports. A preliminary agreement reached in February 1998 calls for Turkmenistan to export 20 Bcm per year to Ukraine through 2005, although as of March 1998 transit arrangements were still being discussed with Russia.

Turkmenistan plans to send 2 - 4 Bcm of gas to northern Iran through the new pipeline to Kurt-Kui, with annual volumes expected to rise to 8 Bcm by 2006. Principal consumers will be several power stations in northern Iran. Ashgabat will not see much revenue from such exports for several years, since they will mostly be used to reimburse Iran for construction of the pipeline.

INVESTMENT

Foreign investment projects

The government officially welcomes foreign investment in the petroleum sector, though as of early 1998 relatively few companies had begun or were planning E&P operations in Turkmenistan. Two projects were operating under production sharing agreements (PSAs).

Bridas (Argentina) is involved in two joint ventures (JVs) to develop the Keymir oil field and the Yashlar oil and gas prospect. In 1996 Bridas took legal action against the Turkmen Government for having revoked its oil export licence, which it claimed had forced the company to sell crude at a loss to a local refinery. Turkmen authorities claim on their side that Bridas exploited its early position in the country to push inexperienced Turkmen negotiators into accepting agreements unreasonably favourable to the company.

Larmag (Netherlands) and **Dragon** (Ireland) participate in a JV to develop an off-shore block located near the Cheleken peninsula. Production was reportedly 7.5 kb/d at the beginning of 1998 and is scheduled to reach 40 kb/d by 2000.

Petronas (Malaysia) has a PSA for an off-shore block (Gubkin, Barimov and Livanov deposits). It reportedly intends to deliver oil to northern Iran in a swap for Iranian oil at Kharg Island. It plans to process this oil at Malaysia's new refinery in Malacca. Eventual production is expected to be 20 kb/d.

7. Shares were Turkmenistan 51%, Gazprom 45%, and Itera 4%. Itera International Energy Corporation is a US-registered company, reportedly with significant Russian ownership.

Mobil (US) and **Monument** (UK) concluded a PSA covering the on-shore Burun field, the unproduced deep sections of Nebit Dag and Kum Dag fields, and the Kyzl Kum gas and condensate field in western Turkmenistan. The project involves recommissioning idle wells at Burun, identifying new deep oil and gas production zones, and commissioning new fields in the area of the Garadepe and Mondzhoukly deposits. Output, which was around 6.5 kb/d at the end of 1997, is set to reach 20 - 30 kb/d by the end of 1998. Monument plans to export crude by ship across the Caspian Sea and up the Volga-Don canal system, as well as to Baku and then by rail to Georgia's Black Sea coast. It is also examining the possibility of oil swaps with Iran. **Mobil** has an additional agreement to work the Karabogazgol gas field.

Abscom Group (Moldova) is carrying out well workovers at the Goturtebe and Barsa-Gelmes fields east of Cheleken. Other companies, including TPAO, Unocal, Delta, Itochu and the China National Petroleum Corporation, reportedly also are looking at E&P projects.

The State Investment Agency and the Competent Body

The government created the State Investment Agency to co-ordinate foreign investment in Turkmenistan. Its responsibilities include checking foreign investment projects against the government's wider investment priorities, signing contracts on behalf of the state, and acting as the official registrar of projects and contracts involving foreign investment.

The March 1997 Law on Hydrocarbon Resources called for a separate co-ordinating body to meet the special needs of oil and gas investors and eliminate the necessity for them to deal with numerous state organisations in establishing projects. The Competent Body, created in June 1997, is based on Kazakstan's State Committee on Investments. It reports directly to the President, who is its nominal head.

The creation of the Competent Body does not eliminate the need to register all activities with the State Investment Agency, although the former is supposed to take care of such formalities on the investor's behalf. The Competent Body can also reportedly assist the foreign investor in applying for tax privileges, which are granted only by the Cabinet of Ministers. However, such privileges appear to be reserved for priority investment sectors outside the oil and gas industry.

The Competent Body co-ordinated the 1997 PSA with Monument and Mobil. It is also responsible for organising the offshore tender, launched in the Autumn of 1997. It would appear that a number of foreign oil companies already active in Turkmenistan continue to deal directly with their contacts in the Ministry of the Oil and Gas Industry and other bodies, at least for existing projects. Both industry and government representatives point out that a major weakness of the Competent Body is the limited amount of oil and gas expertise on its staff.

Offshore tender

The Competent Body launched a tender for offshore blocks in the Caspian Sea in September 1997. Western Atlas, which performed seismic work on the Turkmen shelf in 1996, assisted the Competent Body in organising a number of informational presentations for foreign investors, including in Ashgabat, Houston, Vienna and London. Tender winners are to enter into negotiations with the government on developing the blocks, which may be done on the basis of a production sharing agreement (PSA). State-owned Turkmenneftegaz is to take a 5 - 15% stake in each project. The deadline for submitting bids, originally set for 28 November 1997, was extended to 15 February 1998.

Western Atlas estimates reserves in the Turkmen portion[8] of the Caspian sea at 22.2 billion barrels of crude oil and 4.5 Tcm of gas, although Turkmen authorities have given estimates as high as 50 billion barrels and 5.5 Tcm. The 11 blocks originally offered in the tender are said to hold 17 billion barrels of crude and 1.8 Tcm of gas.

The Turkmen authorities divided the area offshore Turkmenistan into 30 delineated blocks, each around 2,000 km^2. Originally the Competent Body planned to offer 11 of these. However, at the request of the Iranian foreign minister during a visit to Turkmenistan in October 1997, the Turkmen government decided to remove three blocks (25, 26 and 27) straddling the Turkmen-Iranian border. It further announced that these blocks would be developed jointly by Turkmenistan and Iran.[9] The Turkmen government also stated that such an approach could be a precedent for handling disputed offshore fields between Turkmenistan and Azerbaijan.

The Turkmen government has staked claims to the Azeri field and half of the Chirag field, both assigned by Azerbaijan to the AIOC consortium. However, Turkmenistan did not include these among the blocks being tendered. Turkmenistan also claims the Serder field (called Kyapaz by the Azeris), which Azerbaijan originally awarded to Russian companies Lukoil and Rosneft in July 1997. Lukoil and Rosneft subsequently put the project on hold. The Competent Body reportedly included Serdar/Kyapaz in the tender, but later removed it.

Investment legislation

Law on Foreign Investments

The Law on Foreign Investments lists activities open to foreign investors, which include the extraction of natural resources. Article 3 provides a special regime for entities in which foreign participation is more than 20 %. Privileges for such entities are mostly in the area of taxation (see below).

Article 4.2 of the law gives priority to international treaties. The provisions of the Energy Charter Treaty, ratified by Turkmenistan on 12 June 1997, are directly applicable for investments in Turkmenistan.

Article 20 states that the legal treatment of foreign investors and their investments may not be less favourable than that of Turkmen physical and legal persons. It also guarantees that changes in legislation shall not affect an investment already made for a period of 10 years after the investment.

8 Assuming division of the sea into national zones; boundaries remain subject to ongoing discussions.

9 During the October 1997 visit of the Iranian foreign minister, Turkmenistan and Iran also agreed to set up a permanent joint commission to develop a co-ordinated position on the legal status of the Caspian Sea and to discuss joint co-operation on oil and gas development projects and pipelines. The two sides planed to call a conference of all littoral state foreign ministers to try to work out a compromise on the legal status of the Caspian.

Articles 20 - 26 protect foreign investors from nationalisation and expropriation, allow them to transfer property (including foreign currency) abroad under procedures determined by national legislation, and allow them to freely purchase foreign currency within the country. Article 25 protects intellectual property rights.

Law on Concessions

The October 1993 Law on Concessions is directed at foreign investment in a wide range of sectors, including oil and gas. According to this law, concessions are to be granted on a competitive basis, with terms and conditions determined by the Council of Ministers. The law gives the State the right to a share of profits and the right to purchase output from a concession. It gives the concessionaire the exclusive right to use whatever is covered by the concession, the right for compensation in the event of cancellation, and the right to export shares of the output as well as hard currency profits as stipulated in the concession.

Law on Hydrocarbon Resources

The Law on Hydrocarbon Resources, adopted at the end of 1996, takes precedence in case of conflict with earlier laws and regulations, except in the case of international treaties. It claims state sovereignty over Turkmenistan's petroleum resources and establishes a state oil company with the power to conduct petroleum operations, participate in joining ventures, sign contracts and supervise the conduct of petroleum operations in the country.

The Law on Hydrocarbon Resources also establishes the Competent Body, which is responsible on behalf of the state for the exploitation of petroleum reserves and, along with the national oil company, the conduct of petroleum operations.

The Competent Body is given the authority to issue licences to carry out certain types of petroleum operations, though such licences must be approved by the President. A licence must be supplemented by a contract with either the national oil company or the Competent Body. The licence holder is obliged to conclude a contract which determines concrete conditions for the conduct of petroleum operations corresponding to the conditions described in the licence.

Foreign natural and legal persons may receive a licence if they have been registered in Turkmenistan as individual entrepreneurs, have registered a branch in Turkmenistan, or are already members of a joint venture.

The law envisages three types of licences for petroleum operations: Exploration Licence, Production Licence, and Combined Exploration and Production Licence.

Licences are granted on the basis of a tender or direct negotiations carried out by the Competent Body. A tender has two stages: submission of applications for pre-qualification and submission of bidding proposals.

The Law on Hydrocarbon Resources contains a number of administrative requirements, though leaves many elements to be negotiated in the contract between the licensee and the Competent

Body. Such elements include provisions for amendment and termination of the contract (Article 27), detailed conditions for the conduct of petroleum operations (Article 28), and property rights.

The law acknowledges two contract types joint ventures (JVs) and production sharing agreements (PSAs).

According to the law, oil companies pay only a profit tax, royalty and certain bonuses, and are not subject to rate increases and new taxes or levies. Specifically, the law stipulates that a company's tax bill will be held constant for the duration of its contract.

Model PSA and JV agreements

In January 1996 the Turkmen Government adopted a model production sharing agreement (PSA) developed by the Ministry of Oil and Gas in co-operation with the European Union TACIS programme. The Ministry, with the support of the EU, has also developed a model exploration and development joint venture (JV) agreement.

According to the model PSA, agreements are generally concluded for 25 years with the possibility of a 10-year extension. An agreement covering oil exploration and production under which gas is found would not entitle the investor to use the gas for anything but re-injection; producing and selling the gas would require a separate agreement.

The draft model JV agreement generally limits foreign investors' stakes in a JV to 30%, although larger shares are possible and appear to depend on the amount investors intend to spend on exploration. The draft agreement stipulates the duration of exploration and production licences, as well as the investor's share of profits. The latter varies inversely with the profitability of the project, in the range of 10 - 65%. Bonuses and royalty depend on the level of production, within a range of 3 - 15% of output.

Both the PSA and JV model agreements exclude foreign participation in previously explored territories, though give investors a monopoly on oil-related activities in the contract area, as well as the right to construct pipelines.

When commercial production from a field begins, both model agreements stipulate that the only tax that will apply to foreign investors is the 25% profit tax, and only on non-reinvested profits after initial investments are recouped. Royalty, rent and other expenses may be deducted from taxable profits. The model PSA promises compensation for new taxes, while the model JV protects investors against changes in legislation for a period of ten years.

Investors under both model agreements must give preference to Turkmen suppliers, finance social projects, and ensure training of local personnel and the transfer of advanced technology.

The model agreements have been criticised by some for imposing narrow restrictions on investors' activities. Specifically, investors must present detailed annual work programmes and budgets to a project steering committee that includes representatives of the Ministry of Oil and

Gas; once the Committee has approved the programme and budget, investors have little flexibility to make adjustments in actual expenditures.

Dispute settlement

Article 32 of the Law on Foreign Investments places dispute settlement between foreign investors and other legal or physical persons within the jurisdiction of national courts, unless there is an arbitration agreement or unless otherwise determined by applicable international agreements (e.g., the Energy Charter Treaty).

Under the Petroleum Law (Article 56), disputes related to the issue, suspension or annulment of a licence or to the implementation of a contract are to be settled by negotiations or according to dispute settlement procedures provided in the contract. However, if the dispute has not been settled within three months from the date of a written notification, either party may refer the dispute to international arbitration bodies determined in the contract.

All other disputes, including those between the contractor and legal and natural persons of Turkmenistan, are to resolved by relevant Turkmen institutions, unless otherwise provided for in an agreement between the parties to the dispute.

Relevant international agreements to which Turkmenistan is a party take precedence over Turkmen domestic law in the case of conflict between them. (See for example Article 26 of the Energy Charter Treaty, “Settlement of Disputes between an Investor and a Contracting Party”.)

Registration of foreign investors

The Law on Foreign Investments requires legal persons with foreign participation to be registered. Under Presidential Regulation No 1987 of 24 November 1994, such registration is by the Ministry of External Economic Relations. National entities are subject to registration with commissions established under regional authorities.

Privatisation

Article 3.2 of the 1992 Law on Divestment and Privatisation of Property excludes entities and organisations of the fuel and energy complex from privatisation, with the exception of related construction organisations.

Taxation

The Petroleum Law introduces specific rules for taxation and accounting in the petroleum sector (Chapter 9). Some general rules, introduced by other legal acts, may also apply to the extent they do not contradict the rules of the Petroleum Law. Article 48 (Taxes and Payments) provides that the contractor shall pay only the following taxes and levies in the conduct of petroleum operations:

- Profit tax, at rates established by legislation (the procedure for determining the taxable profit is laid down in the contract); and

- Royalty on petroleum production (also determined in the contract).

If new taxes or levies are introduced, the contractor pays only those which substitute for other taxes and levies paid by him; i.e., the overall level of payments is not to exceed the level of taxes and levies imposed at the time the contract was signed. In case of amendments to legislation applicable at the time the contract was signed, including those related to the signature of international treaties, the contractor and the Competent Body may consider appropriate changes in the contract, should that be found necessary to maintain the balance of interests of the contracting parties.

Article 17 of the Law on Foreign Investments establishes a specific regime for taxation of foreign investors and of companies with over 30% foreign ownership. Until the initial capital is recouped, the foreign investor is not liable for paying the dividends tax, and the investment project or enterprise itself is not liable for paying the profits tax. (The modalities may be a part of the contract). Article 17 allows the Council of Ministers to establish other tax privileges.

Free Enterprise Economic Zones

Several Free Enterprise Economic Zones have been established where foreign entrepreneurs enjoy favoured customs and taxation treatment, including exemption from income taxes and land fees for three years, and payment for water, electricity, and gas at reduced rates. Petroleum investments made in such zones may also enjoy such preferential treatment.

Accounting

All enterprises are obliged to follow Turkmen rules for book-keeping and accounting with respect to salaries and social security costs for Turkmen employees, though apply international accounting standards with respect to the contractor's income and costs of petroleum operations, using a freely convertible currency as the monetary unit. (National currency, on the basis of the official exchange rate of the Central Bank of Turkmenistan, is only to be used for the purpose of periodical and annual reports).

Financial auditing is carried out by the Competent Body, or by any other entity designated by the government, including independent auditing companies. Time intervals for auditing are determined in the contract between the investor and the government.

UZBEKISTAN

Uzbekistan at a glance	
Land area	447,400 km^2
Population	23.4 million (1997)
Capital	Tashkent
President	Islam Karimov (since December 1991; term extended to 2000 by a 1995 referendum)
Currency	US $1 = 79 Som (official rate of November 1997)
GDP	US $ 13.9 billion (1996)
Real GDP growth	2.4% (1997 estimate)
Consumer price inflation	40-50% (1997 estimate)
Primary energy production	49.0 Mtoe (1996)
Energy consumption	46.5 Mtoe (1996)

SUMMARY

Reserves and production: Uzbekistan's proven natural gas reserves are the second largest in Central Asia. The magnitude of proven oil reserves is uncertain, but generally believed to be much smaller than those of Kazakstan or Azerbaijan. Significant increases in oil and natural gas production and lower energy demand in the past few years have allowed Uzbekistan to become nearly self-sufficient in energy. The government plans to expand production of both crude oil and natural gas by about one quarter by the turn of the century. Much of this is likely to be taken up by future domestic demand. The government plans to fund most of the required investment from domestic sources or foreign loans.

Exports: Net energy exports in 1996 reportedly were 2.5 Mtoe, or about 5.5% of indigenous production, making Uzbekistan the smallest energy exporter among the four countries reviewed. The country imports a significant part of its refined oil product consumption. Net energy exports are projected to reach 3-6 Mtoe by 2010, mainly in the form of natural gas. This magnitude of surplus is unlikely to be sufficient to support the construction of dedicated export pipelines. Instead, the country may consider "piggy-backing" onto projects to export resources from Kazakstan and Turkmenistan. Uzbekistan faces formidable energy export competition from its central Asian neighbours. Moreover, its oil and gas must travel through more transit countries to reach foreign markets. Lack of access to the Caspian Sea and geographic isolation may prove a constraint to this land-locked country's export flexibility. Net exports of refined products are planned, once the requisite refining capacity is in place.

Investment: Although Uzbekistan has relatively good infrastructure, a well educated workforce and a relatively stable political situation, its investment climate, despite recent progress, is less advanced than those of most of its Central Asian and Transcaucasian neighbours. Investment and tax rules are often conflicting, non-transparent, and lack a consistent system of adjudication and enforcement.

In the oil and gas sector, several projects recently have been completed or currently are being developed, including a new refinery in Bukhara, an upgrade of the Ferghana refinery and a gas compression station at the Kokdumalak oil field. Cumulative foreign investment in Uzbekistan's energy sector increased from near zero in 1993 to US$845 million in 1997. Almost all of this amount was in the form of institutional loans backed by sovereign guarantees. The government would like to increase this figure to US$1.14 billion in 1998. The most serious concerns of potential foreign investors in the oil and gas sector are: inadequate pipeline export capacity, lack of specific oil and gas legislation and of provisions for production sharing or other types of petroleum contract agreements.

ECONOMIC BACKGROUND

Uzbekistan is the third most populous state in the former Soviet Union (23.4 million), and fifth largest in land area (447,400 km^2). The country is well endowed with mineral resources, including gold and non-ferrous metals. It is the world's fourth largest uranium miner, seventh largest gold producer (with fourth largest reserves) and third largest cotton exporter. It is also the tenth largest producer of natural gas, and has been nearly self-sufficient in energy on a net basis since 1994. Manufacturing is concentrated in the textile, automotive and aerospace industries.

After independence in 1991, a new constitution made Uzbekistan a presidential republic. In a March 1995 referendum President Karimov had his term extended until 2000, at which time he may stand for re-election.

Initial reform efforts

Uzbekistan's gradual approach to reforms has been based on five key principles put forward by President Karimov:[1]

- priority of economics over ideology;
- the state as the main reformer;
- the legal foundation for all reform;

1. I. Karimov: "Uzbekistan: Along the Road of deepening of Economic Reform", Houston 1996.

- reforms accompanied by effective measures for social protection;

- consistent and gradual implementation of market principles.

The government's economic policy initially focussed on supporting state enterprises and shielding consumers from inflation through subsidies, strict price controls and periodic wage increases. Given Uzbekistan's relatively low level of industrialisation and relatively efficient agricultural sector, these policies enabled the government to hold its GDP decline to 17% between 1991 and 1994. This compares to an average decline in the FSU of around 40% during this period.

Starting in 1994, after it had become clear that this conservative approach was untenable, the government introduced stricter fiscal policies, froze prices, and began closer co-operation with the international financial institutions. It also introduced privatisation of small (mostly retail) businesses and housing, made overtures to foreign investors and introduced a permanent currency, the som. Liberalisation of prices began in January 1992, was subsequently reversed, then resumed in early 1994. By early 1995, the government had phased out the state order system for all commodities (including energy) with the exception of cotton and grain, although state orders for the latter two gradually have been reduced as shares of output. It also allowed oil and gas prices to approach world market levels later that year.

Inflation

Tight fiscal policies brought annual inflation down from over 300% in 1994 to about 64% in 1995 and an estimated 40-50% in 1997. Inflation is expected to fall to 40% in 1998 and 35% in 1999, provided that Uzbekistan adheres to stabilisation measures proposed by the IMF.

Budget deficit

Tight fiscal policies and a positive balance of trade helped reduce the government's budget deficit from 11% of GDP in 1993 to 7.3% in 1996 and to 3.9% in 1997, according to official government sources. (These estimates, however, are based on a method of calculation which does not appear to conform with IMF standards.)

Progress also was made in reversing GDP's fall from negative 4.25% in 1994 to a positive growth of 1.6% in 1996. The World Bank estimates GDP growth in 1997 at 2.4% and forecasts 2.7% for 1998.

In general, official Uzbek data sources, such as *The Basic Indicators of Social and Economic Development*, are regarded by most outside observers as unreliable and incomplete. This may be partly due to different accounting methods and lack of statistical expertise, though also to a general lack of transparency in government accounts.

Banking

The banking sector remains under firm state control. Private deposits are monopolised by state-owned Sberbank, and state-owned banks control at least 90% of commercial bank assets. Only two of the country's 28 banks are privately owned. With current inflation well in excess of the 20-25% interest on savings deposits, real interest rates are sharply negative, providing a strong disincentive to save.

Privatisation

Nearly 60,000 small-scale businesses (96% of the total) and 2,300 medium and large-sized enterprises (20% of the total) were privatised or leased to worker collectives by the end of 1995, and more than 14,000 private farms created accounting for 11% of arable land. Certain strategic sectors such as energy, fuel and gold mining are currently exempted from privatisation. However, foreign companies are invited to provide technology and services in such exempted sectors in exchange for profit sharing.

In 1997 the government claimed that the "non-governmental" sector accounted for 67% of GDP. This, however, included companies with minority government stakes and firms that were effectively, if not nominally, under government control. Based on definitions conventionally used in the West, Uzbekistan's private sector was estimated by EBRD to account for about 40% of GDP in 1996.

The Tashkent stock exchange was created in 1994 and now lists around 1,000 firms, including a number of Uzbek oil and gas companies. However, most shares in oil and gas companies are still owned by the state (at least 51%) and by the employees of the companies (typically 30 to 49%). The activity of the stock exchange is hampered by limited trading, lack of liquidity, complex rules regarding secondary share sales and capital repatriation, as well as limited use of western auditing procedures. Despite such problems, at least 50 foreign companies, mostly Russian, participate in trading on the exchange.

Trade

Foreign trade is dominated by exports of textiles, cotton and gold, and by imports of machinery, grain and processed foods. In 1996 cotton accounted for about 38% of Uzbek exports (US$4.6 billion total) and foodstuffs accounted for around 30% of imports (US$4.7 billion total). Bad harvests and low international prices for cotton had an adverse effect on the Uzbekistan's current account in 1996, resulting in a negative balance of 7.9% of GDP. This improved in 1997 to negative 6.5%, though the government remained highly concerned about the overall balance of payments and reserves position. Bilateral barter-type agreements with governments are still the norm between Uzbekistan and many FSU countries.

In mid-1996 the government began a campaign to promote exports and import substitution. Export duties were eliminated on a wide range of goods, except for gold, cotton, oil and gas. Products still subject to quotas and licensing are oil, cotton, and ferrous and non-ferrous metals. Other incentives for exporters include the elimination of VAT and other taxes on exported commodities, and a seven-year tax holiday for joint ventures in which foreign partners have a combined equity position of over 30%, or which export over 50% of their output. However, this privilege does not apply to ventures in the oil and gas sector. In the near future, this tax holiday may be extended to new domestic companies, but only in selected priority sectors.

The government is making an effort to curb rising imports through currency restrictions and tariffs, which were reintroduced in mid-1995 following their suspension in January 1994. However, the maximum rate was reduced in April 1996 to 30%, and the typical range in 1997 was 10-20%. Exemptions may be granted for goods imported as a contribution to the authorised capital of a joint venture and for equipment produced by, and imported for, foreign companies with total direct investments in Uzbekistan exceeding US $50 million.

Multilateral assistance

The fiscal discipline displayed by the government in 1994-1995 attracted considerable support from various multilateral lending institutions.

The International Monetary Fund (IMF) approved a US $141 million Systemic Transformation Facility in January 1995 (disbursed in two tranches in February 1995 and December 1995) and a US $400 million Stand-By Arrangement in December 1995. The latter was suspended in November 1996 as a result of increased inflation and problems surrounding hard currency convertibility. As of the beginning of 1998 it had not been re-instated.

The World Bank is responsible for co-ordinating assistance to Uzbekistan for institution-building, infrastructure development, cotton sector reform, and human resources development. The bank has provided a US $160 million rehabilitation loan and is expected to provide a total of $400-500 million in project finance over the next five years. The initial loan did not directly affect the energy sector, though some future funds reportedly may be used to finance energy projects.

The European Bank for Reconstruction and Development (EBRD) has provided technical support for Uzbekistan and has sought investment opportunities in the country's private sector, particularly in energy, agribusiness, telecommunications, tourism, transportation, and environmental activities. As of mid-1997 the EBRD had committed US $251 million for ten development projects in Uzbekistan, including two in the energy sector: the upgrading of the Ferghana refinery and the renovation of the Syr Darya power plant.

Problems in late 1996 related to an expansion of the money supply, and Uzbekistan's failure to move toward full convertibility of the som, undermined relations with the multilateral lending institutions. Following the government's establishment of strict controls on access to hard currency in October 1996, the IMF announced in December 1996 a suspension of the Stand-By Arrangement pending the establishment of corrective measures. Uzbekistan's draft 1998 budget did not show any IMF credits, which indicates that an agreement with the IMF was not expected during 1998.

The World Bank's Tashkent representative followed the IMF's lead in February 1997 by suspending a US $180 million loan aimed at supporting the privatisation process in Uzbekistan. Uzbek officials have indicated that the government will not be able to meet the IMF requirements immediately, but will make efforts to introduce convertibility of the som within the next two to three years.

Some reports indicate that Uzbekistan's hard currency reserves are now seriously depleted. Companies are obliged to convert 30% of gross revenue to som at the official exchange rate, which is less than half of the black market rate.[2] Foreign companies are allowed to take out hard currency only to pay for travel.

Uzbekistan is the largest market in Central Asia, has a good physical infrastructure, a relatively well educated workforce and a relatively stable political climate. However, the country's investment framework lags behind that of some of its neighbours. Investment and tax rules are often conflicting, non-transparent, and lack a consistent system of adjudication and enforcement. Foreign companies complain about the high level and unpredictability of taxes and the lack of currency convertibility.

There is no petroleum legislation or provisions for production sharing agreements. However, using a US$300,000 loan from the World Bank, the government hired UK legal firm Clifford Chance to prepare oil legislation. The draft legislation was subsequently revised by Hagler Bailly and submitted to Uzbekneftegaz in December 1997. The government has also worked on such legislation with technical advisors provided by USAID.

Official estimates indicate that Uzbekistan has received $7-8 billion in investment from foreign sources between 1991 and 1998. These funds were mainly in the form of bank loans with state guarantees backed by gold reserves. Such guarantees amounted to $600 million in 1996 and may have been over US$ 1 billion in 1997.

According to the Foreign Investment Agency, an institution funded by UNDP and the Uzbek government to promote foreign investment, foreign direct investment (FDI) has accounted for less than US $1 billion since 1991. Estimates of Uzbek FDI by the IMF and EBRD are much lower, at US$200 to US$300 million from 1992 through 1996. The bulk of this investment was used for a car plant and various smaller industrial ventures. Most of the rest reportedly was invested in Uzbekistan's energy sector.

The country is seeking around $8 billion in foreign investment from 1998 through 2003 to fund gas, power, telecommunications, road, rail and other projects. Uzbek energy officials predict the future flow of investment to average around $1.5 billion annually. Presumably most of this would be in the form of foreign loans rather than foreign direct investment.

Foreign investors are allowed to assume a 100% ownership of new companies, but only up to 49% ownership of existing state companies.

International economic relations

In its foreign relations, Uzbekistan has moved to strengthen ties with neighbouring Central Asian states as well as with countries outside the region. In August 1996, Kazakstan, Kyrgyzstan and Uzbekistan signed an agreement to create a "special economic zone" in their border areas. This is to be part of a larger effort toward a "unified economic development area". Uzbekistan has not

2. The joint venture with Newmont Gold is exempted from this requirement.

been as enthusiastic as some of its neighbours (notably Kazakstan) regarding the so far unsuccessful efforts to group Central Asian countries into a regional economic bloc.

Uzbekistan is currently considering membership in a CIS customs union which may provide significant benefits to foreign firms interested in exporting goods produced in Uzbekistan to other CIS countries.

In 1992 Uzbekistan became a member of the United Nations, the IMF, EBRD, IFC and the Multilateral Investment Guarantee Agency. It is also a member of the Asian Development Bank. The country has ratified the Energy Charter Treaty, is an associate member of WTO and plans to become a full member. In November 1996 the European Communities (EC) and Uzbekistan signed the Partnership and Co-operation Agreement aimed at enhancing trade and other ties. However, as of the beginning of 1998 the agreement had not been ratified by the European Parliament, which has been concerned that Uzbekistan may not meet the democratisation, human rights and economic reform criteria.

Uzbekistan entered into a Bilateral Trade Agreement with the US in January 1994, that provides Most Favoured Nation status for the products of both countries. Uzbekistan has similar agreements with over 20 other countries, including China, the UK, South Korea, Israel and Turkey.

Uzbekistan and the US have also signed a Bilateral Investment Treaty which guarantees companies from the two countries the right to invest on the same terms as those accorded to domestic or third country investors. However, the US has withheld ratification pending Uzbekistan's removal of its currency convertibility restrictions, which are not in compliance with the treaty commitments.

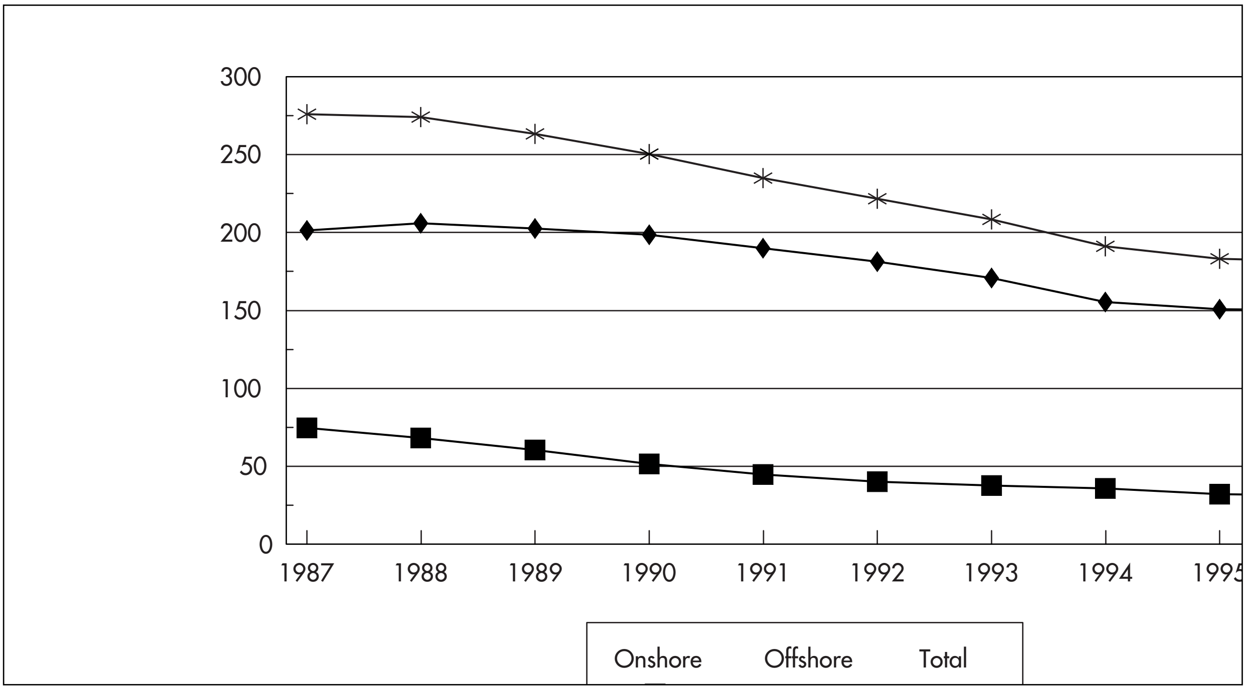
OVERVIEW OF THE ENERGY SECTOR

Uzbekistan is the only FSU country not to have experienced a decline in oil and gas production after the breakup of the Soviet Union. Since 1994 it has also been nearly self-sufficient in energy on a net basis. (Uzbekistan reportedly still imports significant amounts of refined products). Net energy exports in 1996 were 2.5 Mtoe, or about 5% of indigenous production, making Uzbekistan the smallest energy net exporter among the four countries reviewed. Virtually all energy exports were in form of natural gas.

Increases in crude oil and natural gas production over the past five years, combined with a considerable rise in relative energy prices, have increased the importance of the energy sector in the economy. The energy industry represented around 11.1% of GDP in 1995. State revenue from energy specific excise taxes amounted to 11% of total budget revenue in 1995 which, combined with VAT, corporate income tax and other general taxes, makes the sector's contribution to the state budget considerably higher than its share in GDP.

In 1996, Uzbekistan produced around 49 Mtoe of primary energy, 25% more than in 1991. Of this amount, around 80% was in the form of natural gas and 15% in the form of oil. Most of the increase occurred in crude oil, the production of which nearly tripled. Natural gas production has also registered modest gains. Uzbekistan is now the largest gas producer in Central Asia, following the significant decrease in Turkmen gas production. However, Uzbek production rates appear to have stagnated in late 1996 and early 1997.

Figure 1 Uzbek primary energy consumption in 1996



Domestically produced natural gas and crude oil dominate Uzbekistan's energy supply, accounting for about 77% and 15% of primary energy consumption, respectively, in 1996. The remainder came from coal and hydro electricity. Primary energy consumption amounted to around 46.5 Mtoe in 1996, almost the same level as in 1991. Demand for fuels and electric power has held up relatively well. In part because Uzbekistan was relatively less economically dependent upon Russia and other FSU states, it was able to avoid, or at least delay, some of the economic dislocation and restructuring experienced by most other FSU countries.

The reversal in the country's net export position has been due mainly to a combination of lower energy demand and increased oil production. Most of the increase in oil production appears to have come from one field (Kokdumalak); production at other fields is not published, though may match declining trends experienced by other oil-producing FSU countries.

In the near term, the government appears to be concentrating on self-sufficiency, due to a projected strong growth in population (2.1% per year) and in energy use. Its long term goal, however, is to become a modest net exporter of oil and gas. The government has identified 32 new oil and gas fields to be developed, an additional 18 for rehabilitation, and 9 more for exploration. Net exports of energy are projected by the government to reach 6 Mtoe by 2010, mainly in the form of natural gas. Some oil companies operating in Uzbekistan have expressed the opinion that oil production probably will be less than forecasted.

Table 1 Energy supply, demand and net exports: 1997-2010 (Mtoe)

	Supply	Demand	Net exports
1990	38.6	43.7	-5.1
1991	39.2	46.5	-7.3
1992	40.5	45.2	-4.7
1993	42.7	47.2	-4.5
1994	46.3	45.5	+0.8
1995	49.0	46.5	+2.5
1996 (est.)	49.0	46.5	+2.5
2000	51.7	48.6	+3.1
2005	55.7	52.3	+3.4
2010	60.6	54.9	+5.7

Source: IEA low case scenario and PlanEcon

Electricity

Uzbekistan has 37 power plants with a total combined generating capacity of 11,800 MW. It produced 45.2 TWh in 1996 and was expected to produce a similar amount in 1997. This was sufficient to meet domestic demand and allow for small-scale exports to neighbouring countries. Some idle capacity is emerging because demand for power has dropped, though according to the government, the fall has not been as significant as in neighbouring FSU countries.

Electricity in Uzbekistan is mainly produced from natural gas-fired thermal plants (77% of total), with smaller portions from hydro (10%), coal (6%) and fuel oil (7%). The largest power stations are the natural gas-fired ones in Syr Darya and Navoi. The entire power system is owned by the state, though some auxiliary infrastructure is being privatised. An interconnected power system allows for interchanges among Tajikistan, Kyrgyzstan, Uzbekistan, Turkmenistan and Kazakstan. In exchange for electricity deliveries in the Winter, Uzbekistan receives electricity and water for irrigation purposes from Kyrgyzstan and Tajikistan in the Summer.

The projected rate of growth for electricity demand is now 3-5% annually, which is close to most western expectations of Uzbeck GDP growth. However, this is a significant downward revision from the government's previous forecast of 5-7% annually.

Increased demand is to be met through the construction of new power plants using mainly natural gas. No nuclear power plants are planned because of the danger posed by earthquakes in Uzbekistan. Plans to boost Uzbekistan's generating capacity by 4,000 MW in the near future include the renovation of the Syr Darya, Angren and Tashkent plants, and the construction of a thermal plant near Termez and a hydro-power plant in Pskem. The EBRD is providing some funds for the Syr Darya project.

Energy prices

Oil and gas prices are set by the Ministry of Finance. In early 1998, 76-octane petrol sold domestically for US$200-225 per tonne, while the price for diesel was US$100-125 per tonne.

The domestic price for natural gas for industrial users at the end of 1995 was US$32 per thousand cubic metres, or less than half the cif import price. Gas prices for households were much lower. The installation of gas meters is not widespread in Uzbekistan.

ORGANISATION OF THE OIL AND GAS SECTOR

In 1992 the Uzbek government merged all major components of the country's oil and gas sector into state-owned Uzbekneftegaz. In 1993 it transformed Uzbekneftegaz into the National Corporation of the Oil and Gas Industry (Uzbekneftegaz Corporation), a "business association of voluntary members" including state-owned, lease-held[3], collective and joint venture enterprises involved in the exploration, production, transportation and processing of oil and natural gas. The Uzbekneftegaz Corporation currently comprises 14 major associations and enterprises, which include more than 250 smaller divisional enterprises jointly employing 90,000 people. Using world prices, Uzbekneftegaz Corporation estimates that in 1995 it produced US$6.3 billion in output and services.

The main components of the Uzbekneftegaz Oil and Gas Corporation are:

- State Joint Stock Company "Uzneftegazdobytcha" (exploration, development and production of oil and gas, processing of gas and commercial drilling);
- State Joint Stock Association "Uzneftegazstroy" (construction of petroleum production, transport and processing facilities and housing);
- State Association "Uztransgaz" (transportation and sale of gas to major domestic industrial users and to export markets, and construction of long distance gas pipelines);
- State Joint Stock Association "Uzgaznefteproduct" (purchasing and marketing of petroleum products to industry and private customers);
- State Geological Enterprise "Uzbekneftegazgeology" (prospecting and exploration for new oil and gas fields, specialising in deep drilling in the Kungrad, Alat, Karaulbazar, Kasan, Guzar, Karshi and Tashkent regions);
- State Geophysical Enterprise "Uzbekgeophysics" (performance of geophysical surveys, interpretation and research, identification and characterisation of potential oil and gas fields for exploration drilling);
- State Production Association "Uzneftepererabotka" (processing of oil and gas condensate);

3. Lease-held enterprises exist mainly in the mining sector and are typically "build-operate-transfer" (BOT) ventures.

- Scientific-Production Association “Neftegasnauka” (exploration and production research for the oil and gas sector).

Uzbekneftedobytcha is the main upstream operator, accounting for virtually all of Uzbek oil and gas production except for small volumes of gas produced by Uztransgaz from the Gazli deposits. Ubekneftedobytcha also carries out geological surveys in the Ferghana and Surkhandarya regions. (Uzbekneftegasgeology is responsible for exploration in the rest of the country.) Ubekneftedobytcha is not involved in oil refining, but processes natural gas at the Mubarek and Shurtan plants.

Although there is no ministry to deal specifically with energy issues, the Deputy Prime Minister holds the post of Chairman of Uzbekneftegaz, and in practice the Corporation formulates Uzbek energy policies in the oil and gas sector. As of the end of 1997 it was preparing an oil and gas development plan through 2010 which is expected to prescribe a rate of development similar to that of recent years.

OIL RESERVES AND PRODUCTION

Uzbekistan includes portions of several of Central Asia’s rich hydrocarbon basins, and its reserves could allow it to become a modest energy exporter, particularly of natural gas. However, its geological prospects are not considered to be as favourable as those of neighbouring Kazakstan or Turkmenistan. The country is also slightly more remote from export markets and lacks access to the Caspian Sea.

There are five oil and gas bearing regions in the country: Ust-Yurt, Bukhara-Khiva, Southwestern Gissar, Surkhandarya, and Ferghana. More than 150 oil and gas fields have been discovered, of which about 60 are currently in operation. The most important are Gazli, Shurtan, Kokdumalak and Mingbulak. Producing horizons range from 800 metres in Buhkara-Khiva to 6,000 metres in the central part of the Ferghana depression.

Uzbekneftegaz estimates the country’s oil reserves at 527 Mt (3,900 Mb),[4] while most outside sources give significantly lower figures. A 1997 US government report put proven oil reserves at 27 Mt (200 Mb), with another 135 Mt possible.[5] Another source estimates proven and possible reserves at 513 Mt for crude oil and 162 - 216 Mt for condensate.[6] One reason for the discrepancies is that resource classifications used in Uzbekistan and other former Soviet republics are not easily comparable with those used outside the FSU. Uzbek officials may include some potential reserves, classifying as proven some reservoirs that have not been delineated by drilling, as well as reservoirs with untested occurrences encountered during drilling.

4. In recent years the government has significantly increased its estimates of the country’s oil reserves. Evidence on which to base these increases is not clear to many outside observers.
5. Report to congress on Caspian Region Energy Development, 1997.
6. Petroconsultants of Geneva, Switzerland.

Table 2 Oil reserves estimated by Uzbekneftegaz as of 1 January 1996 (Mt)

	Proven	Potential
Crude oil	527	4,400
Condensate	198	630

Source: Uzbekneftegaz

Crude oil was first discovered in Uzbekistan in 1880 at Shorsu in the Ferghana basin, which straddles the country's borders with Tajikistan and Kyrgyzstan. The Ferghana basin's oil and gas fields are relatively small in terms of average size (3 Mt of oil and 1.2 Bcm of non-associated gas) and geographic extent. However, estimates of the basin's potential increased significantly with the 1983 discovery of the Mingbulak field, which Uzbekneftegaz feels could contain some 22 Mt of oil and 16.3 Bcm of natural gas. The recent drilling of 11 dry holes in the field suggests that these reserve estimates are optimistic. Recoverable reserves for the entire Ferghana basin (covering also parts of Tajikistan and Kyrgyzstan) are estimated by Uzbekistan at 540 Mt of oil, including 135 Mt proven and 405 Mt possible. Approximately 65% of the basin's recoverable oil reserves and 75% of its associated gas reserves are thought to lie in Uzbekistan.

The Bukhara-Khiva region accounts for about three quarters of Uzbekistan's recoverable oil reserves. The Ferghana and Surkhandarya regions account for the remaining quarter. The degree of depletion varies from 28% in the Bukhara-Khiva, to 75% in Ferghana and Surkhandarya. As of 1 January 1997, oil was being produced at 59 fields. The Kokdumalak field, located south of Bukhara near the border with Turkmenistan, is the country's largest producing field.

Table 3 Kokdumalak reserves

	Total	Recoverable
Oil (Mt)	98.6	54.3
Condensate (Mt)	96.3	67.4
Associated gas (Bcm)	22.6	12.4
Non-assoc. gas (Bcm)	143.7	126.8

Source: Interfax

Exploration

In 1994 Uzbekistan drilled 18 exploration and appraisal wells and 15 development wells, down from the respective figures of 48 and 21 for 1993. (More recent drilling statistics were not available.) During the period 1991-1995 Uzbekneftegaz discovered some 25 oil, gas and condensate fields, including 18 in the Chardzhou region. Four fields were discovered in the southwest arm of the Gissar foothills, and the remaining three in the Ferghana and North Ustyurt basins. Most recent discoveries are classified as small (less than 10 Mt of oil or 10 Bcm of gas). The largest recent oil discovery was at Mingbulak in March 1992, where initial oil flow was reported at 35-62 kb/d.

At present, there are no foreign joint ventures in oil exploration. In November 1996 Uzbekistan signed preliminary agreements with Unocal to evaluate the country's potential crude oil and natural gas resources. The government is also discussing five other exploration projects with foreign partners, spanning all five of the country's main oil regions: two blocks in Karakalpak, three in Beshkent, a combined block in Gissar and Surkhandarya, and two in Ferghana. There are also plans for a joint project with Kazakstan to explore for oil and gas in the Aral Sea region.

Production

Crude oil and condensate production has been on a steady upward trend since 1991, rising from 2.8 Mt to 7.6 Mt by 1996. During the first nine months of 1997, Uzbekistan produced 5.7 Mt, up 1.8% over the same period of 1996, implying the annual production of around 7.8 Mt for the year. Crude oil reportedly made up two-thirds of the total, and condensate the remaining third, although some sources indicate that condensate may have accounted for the larger portion.

Table 4 Crude oil and condensate production: 1990-1996

	Mt
1990	2.8
1991	2.8
1992	3.3
1993	4.0
1994	5.5
1995	7.6
1996	7.6

Source: IEA, PlanEcon and others

The increase in production since 1991 runs contrary to the declining trends experienced by all other FSU oil producers. It has been attributed to the government's strong political support for the oil sector in the form of loan guarantees which have allowed the industry to borrow over US $1 billion internationally since 1991. It also would appear that because Uzbekistan did not suffer the economic dislocations experienced by most other FSU republics, development funds for the oil and gas sector remained relatively more plentiful. Much of this investment from loan capital may have gone into the Kokdumalak field, which accounts for a significant percentage of total output. Since figures for oil production by field are not made available by Uzbekneftegaz, the status of output at other Uzbek fields is not clear. While overall Uzbek output is up, it may be that output from the Kokdumalak field has made up for declines at some other fields. Production in recent years has been mainly from the Kokdumalak and Mingbulak oil fields.

It is estimated that Kokdumalak currently produces some 3.9 Mt/year, or half of Uzbekistan's total oil and condensate output. There are plans to increase production from this deposit to 6.4 Mt/year in the near future through the construction of a cyclic process compression station which will inject high-pressure gas into the reservoir. Development plans for Kokdumalak have been facilitated by the recent resolution of a dispute with Turkmenistan over ownership and development rights to the field. The agreement stipulates that Uzbekistan is to give Turkmenistan 570 kt of oil per year for 15 years in exchange for full development rights and eventual ownership. The field was discovered by Uzbekneftegaz, which has carried out all appraisal and development work to date.

The Bukhara-Khiva region, which contains the Kokdumalak field, accounted for about 92% of oil production in 1995. The other two producing regions, Ferghana and Surkhandarya, accounted for 5% and 3%, respectively.

Uzbekneftegaz plans to pump a total of 8.8 Mt of oil in 1998, and up to 10 Mt by the turn of the century. The implied 22% increase over the figure for 1996 is to come primarily from expansion of the Kokdumalak field, where annual output is expected to increase by 2.5 Mt by 2000 due to investments backed by the US and Japanese export-import banks. Most of the incremental oil will be used domestically.

Until fairly recently, the oil output target was only 9 Mt for the period 2000 - 2010.The recent emphasis on increasing production is a result of a shift in economic policy towards achieving significant oil exports. The official goal is to produce 12-15 Mt annually for the period 2010 - 2020. Some western observers view this goal as obtainable. For example, Petroconsultants anticipates oil production reaching 10.7 Mt/year in 2000 and 15.7 Mt by 2020.[7] Others are more sceptical, pointing out that Uzbek officials may have significantly overestimated reserves and production potential.

IEA estimates of exportable surpluses are not optimistic, due to projections of significant domestic energy demand, despite relative progress in energy efficiency in industry. Due to Uzbekistan's large population, further gains in energy efficiency in the household sector could have a fairly large impact on exportable surplus.

OIL REFINING

Oil from the Bukhara-Khiva and Ferghana regions supplies the Ferghana and Alty-Aryk refineries through feeder pipelines and by rail. Oil produced at Surkhandarya fields is used mainly by Uzbek asphalt-bitumen plants.

Until recently, Uzbekistan had only two major oil refineries: Ferghana, with an annual throughput capacity of 5.4 Mt; and Alty-Aryk with 3.3 Mt. A third, the newly constructed Karaulbazar refinery in Bukhara Oblast, began operations in August 1997. Karaulbazar is expected to reach its full initial annual capacity of 2.5 Mt in 1998. This should boost Uzbekistan's annual output of unleaded petrol by 660 kt, diesel by 1.33 Mt, and aviation fuel by 300 kt. The refinery's products reportedly will conform to world standards. Although the new

7. Petroconsultants Foreign Scouting Service, April 1997.

refinery probably will create a temporary surplus of capacity, this should disappear by the turn of the century as domestic oil production and demand increase. The possibility of doubling the new refinery's annual capacity to 5.0 Mt in the future was anticipated in the original plans.

A US $200 million upgrade of the Ferghana refinery was under way in 1998 in order to deepen the refining process and to adjust from Russian to local crude streams. This project is being carried out by Mitsui over a two- to three-year period on the basis of a contract, with control of the refinery remaining with the Uzbek government. The refurbishment will require a reduction in the refinery's throughput in 1998. When completed, it is expected to improve the quality of products and boost production by 300 kt of diesel, 80 kt of petrol and 25 kt of sulphur. A desulphurisation plant (1.7 Mt capacity) is to be built at the refinery to aid the switch in feedstock from low-sulphur Russian crude to high-sulphur crude from Kokdumalak. Texaco has developed a $10 million JV with GPO Uzneftepererabotka to produce lubricants at an existing blending plant within the Fergana refinery.

Before independence, over three quarters of oil refined in Uzbekistan was supplied from western Siberia. These supplies gradually were replaced by domestically produced crude oil and condensate until they were discontinued completely in 1995.

Combined annual refinery output has increased from 6.1 Mt in 1992 to 6.6 Mt in 1994 and an estimated 6.9 Mt in 1996. Data for the first five months of 1997 indicate that refinery output increased to around 7.1 Mt for the full year.

The largest users of petrol are: the agricultural sector (34%) and public and private transport (52%). Diesel fuel is used mainly in agriculture (68%), transport (14%) and industry (12%). Virtually all fuel oil is used by the industry. Almost all Uzbek oil product output is directed at the domestic market and are distributed through a privatised network of 88 oil distribution bases and 627 refuelling stations.

The Government, seeking to limit its future dependence on imported products, particularly diesel, initiated a project to convert 2,000 vehicles (40% of vehicles in the farming and mining sectors) to run on compressed natural gas (CNG). The conversion was organised by the Gasmotor joint venture, which also was to manufacture the conversion components and market the product and expertise abroad. The programme was expected to replace 2 billion litres of liquid fuel consumption over the next five years and to decrease emissions of carbon monoxide by 60-70% and of nitric oxide by 15-20%. The programme reportedly ran into difficulties due to the western investors' inability to raise the required capital and to the (government controlled) price levels of competing fuels, which are rendering CNG uncompetitive.

OIL TRANSPORTATION AND TRADE

In 1991 Uzbekistan imported 8.5 Mt of crude oil and petroleum products, over half of which were supplied by Russia. Petroleum products have been an important component of Uzbek oil imports. By 1996, crude oil imports ceased as a result of rising indigenous production and lower demand. Since 1996, Uzbekistan has shipped oil products such as diesel, petrol and lube oil by rail to neighbouring countries and to western Europe, primarily Germany, Switzerland, and Italy. The number of available tank cars limits total transport capacity to 1.5 Mt/year.

In the past few years, higher rail tariffs within Uzbekistan and Central Asia and the low quality of products from the Ferghana refinery have adversely affected export volumes. In 1997, oil product exports were expected to reach about 0.2 Mt. Oil products are now exported mainly to neighbouring Kyrgyzstan, Tajikistan, Kazakstan and Afghanistan. In addition, 574 kt of crude oil and condensate were to be delivered during 1997 to Turkmenistan's Chardzhou refinery. The opening of the Karaulbazar refinery in Bukhara should improve the quality of products, which in turn is expected to boost product exports to a planned level of 1.5 Mt in 1998.

Uzbekistan's goal is to become a modest net oil exporter. A large portion of exports may be in form of petroleum products shipped by rail to neighbouring countries. Some products may also be transported by road to the Black Sea port of Poti and then shipped to European markets. Beyond 2010 further increases in Uzbek oil exports will be contingent on the development of new export pipeline capacity.

Table 5 Projected oil supply, demand and net exports: 1997-2010 (Mt)

	Supply	Demand	Net exports
1997	7.8	7.3	0.5
2000	10.0	8.7	1.3
2005	11.0	9.0	2.0
2010	12.0	10.0	2.0

Source: IEA low case scenario

Oil transportation

Uzbekistan's oil distribution network contains some 9,500 km of pipelines. At present Uzbekistan does not have any pipelines for crude oil exports. However, it does contain a section of a pipeline that originates in the western Siberian city of Omsk, crosses Uzbekistan and terminates in Chardzhou, Turkmenistan; this could be reversed to allow for exports to or via Russia.[8] The portions of the pipeline in Uzbekistan and Turkmenistan (6 Mt/year capacity) are currently not in service, but could link to the proposed pipeline from Turkmenistan to Pakistan via Afghanistan. (See Turkmenistan chapter.)

An oil products pipeline from Chinaz to Shimkent (Kazakstan) is currently out of operation.

8. The Omsk-Pavlodar section of the line is 318 km long, with a diameter of 1,000 mm. The Pavlodar-Shimkent section is 1,627 km long with a diameter of 800 mm. The Shimkent-Chardzhou section is 700 km long with a diameter of 700 mm.

Proposed export pipelines for oil

Volumes of Uzbek oil available for exports are unlikely to be sufficient to support the construction of a dedicated pipeline to markets beyond the FSU. At least in the medium term, piggy-backing onto projects to export oil from Kazakstan and Turkmenistan may provide a reasonably cost-effective export option.

In November 1996 Uzbekistan signed an agreement with Unocal to examine the feasibility of tying part of Uzbekistan's pipeline network into Unocal's proposed Central Asia Oil Pipeline (CAOP). The CAOP is to export Turkmen, Kazak and possibly Uzbek oil through Afghanistan to a proposed deepwater port in Gwadar on Pakistan's Arabian Sea coast. An Uzbek spur could connect with the proposed pipeline at Chardzou, Turkmenistan. Excess capacity would probably be sufficient to handle all of Uzbekistan's projected exportable surplus through the medium term. (For more details see the Turkmenistan chapter.) CAOP would likely utilise an existing idle oil pipeline in Uzbekistan and possibly convert an existing gas pipeline to supply crude from the Tengiz area to Chardzou for onward transport. Should this occur, the Uzbek government could be in a strategic position to control the feeder lines for this potential major North-South transport corridor.

Another possibility being examined is shipping oil east to China and Japan by tying into the proposed 1,800-km pipeline from Kazakstan to western China. (For more details see the Kazakstan chapter.)

GAS RESERVES AND PRODUCTION

Estimates of Uzbekistan's proven natural gas reserves vary between 1,600 and 2,100 Bcm, with additional possible reserves of around 1,000 Bcm.[9] The government's estimate is 2,007 Bcm for proven reserves and 5,439 Bcm for potential reserves.

According to the Uzbek government, additions to proven reserves were 30 Bcm in 1994 and 160 Bcm in 1995. In recent years new reserves have come mainly from ongoing appraisal of the following:

- Barsa-Kelmesh Depression, western region (Barsakelmesh Zapadniy and Urga fields);
- Chardzhou Structural Terrace (Berdykuduk and Shakarbulak fields);
- Gissar Foothills (Chegara and Istmok fields); and
- Amu Darya basin (Kalandar, Shoda and Suzma Severniy fields, as well as new oil and gas fields at Mullakhol and Uchburgan, and a new deep pool at Kokdumalak).

9. For example, see Report to Congress on Caspian Region Energy Development, 1997.

Uzbekistan's proven natural gas reserves are large enough to allow the country to become at least a modest exporter. However, in gas export markets outside the FSU, Uzbekistan faces formidable competition from Kazakstan and Turkmenistan, both of which have had more experience selling gas beyond Central Asia. With the probable exception of potential markets in the Indian sub-continent, Uzbek gas must travel through more transit countries than gas from most of its competitors, and thus face potentially higher transit tariffs. This tends to reduce the competitiveness of Uzbek gas outside the region.

Bukhara-Khiva is the country's main gas-bearing region, accounting for over 90% of Uzbekistan's initial established gas reserves. Gas is currently produced at 52 fields, which according to Uzbekneftegaz contain some 1.3 trillion cubic metres of remaining gas reserves. The largest producing field is Shurtan. Other major gas-producing fields include Zevardy, Danghizkul-Khauzak, Alan, Kokdumalak, Pamuk and Urtabulak.

In 1953 Uzbekistan's first gas field, Setalan-Tepe, was discovered in the Kyzylkum desert. Commercial production of gas began in 1958 and was boosted in 1962 by the discovery of the Gazli field. In recent years, gas production has been on a steady upward trend, rising from 40.4 Bcm in 1990 to 49.2 Bcm in 1996 (the latter figure was slightly below the official target of 50 Bcm). During the first five months of 1997 production appears to have stagnated, increasing by only 0.6% over the same period of 1996. The target for 1997 was 50 Bcm, up only 1.6% over the 1996 level. The government's longer term aim is to reach 60 Bcm for the period of 2000 - 2010. This is to be achieved partly through the construction of a new sulphur extraction plant at Kokdumalak which should boost the field's annual gas production by 6 Bcm.

Table 6 Natural gas production: 1990-1996 (Bcm)

	Total
1990	40.4
1991	41.8
1992	43.2
1993	45.4
1994	48.0
1995	48.6
1996	49.2

Source: IEA PlanEcon and other sources

Gas production is concentrated in southeast Uzbekistan in older fields such as Shurtan, Gazli and Kokdumalak, with Shurtan producing over one third of the total (about 18 Bcm/year). The share of associated gas in total gas production has been growing rapidly since 1994 due to the accelerated development of the Kokdumalak oil and gas condensate field and increased recovery efforts.

Gazli is Uzbekistan's largest gas field. Its recoverable reserves are triple those of Shurtan, though due to its remote location relative to markets, it has not been fully exploited and is now used mainly for underground storage. In 1997 a joint Uzbek-Ukrainian-Russian venture completed construction of the first section of a 125-km gas pipeline linking the Gazli field with the city of Nukus in the remote Northwest of the country. The US $63 million pipeline was commissioned in November 1997. It has an annual carrying capacity of 8 Bcm, which will be increased to 11 Bcm after the construction of a compressor station. The line will permit Uzbekistan to eliminate annual imports of 3.5 Bcm to this region from Turkmenistan. Uzbekistan is to pay for the construction by delivering 1.9 Bcm/year of gas to Russia for five years.

Development of the Urga field in the North Ustyurt Basin started in 1995. Initial annual production is estimated at 0.14 Bcm, but could reach 0.5 Bcm within a few years. Production is to be exported to Ukraine via a 40-km spur to the Bukhara-Urals trunkline. Other new fields being developed by Uzbekneftegaz include the Mubarek group and an intermediate structure in the Shurtan field. There are plans to enlarge the existing pipeline from Mubarek to Yengirey (420 km) and to revamp the compressor stations to handle the incremental volumes.

Enron Oil and Gas International is negotiating E&P rights to develop 11 gas fields, nine in Bukhara-Khiua region and two in Surkhandarya. Uzbek companies have drilled more than 30 exploration and 24 development wells in these fields, the reserves of which they estimate at 170 Bcm of gas and 600 Mb of condensate, sufficient to ensure a production life of about 30 years. The fields are expected to produce around 1.5 Bcm per year initially and peak at 6 Bcm per year.

GAS PROCESSING, TRANSMISSION AND DISTRIBUTION

Most Uzbek gas requires extensive processing to remove a high content of sulphur. Most is processed at the Mubarek gas processing plant. In December 1996 Mubarek commissioned its fifteenth sulphur purification unit, bringing processing capacity of the plant to 35 Bcm per year. Current annual output is around 25 Bcm. Gas is also processed at the Shurtan plant, which has an annual capacity of 30 Bcm, and at a small desulphurisation unit at the Uchkyr field with an annual capacity of 0.9 Bcm. In December 1996 a gas extraction and processing plant was commissioned at Alan, in the southern Kashkadarya region, with a design capacity of 5 Bcm per year of gas and 200 kt of gas condensate. In 1997 throughput at the Alan plant was expected to be 2.5 Bcm.

Uzbekistan has a well developed system of field and trunk gas pipelines, ensuring adequate transport of gas to both domestic consumers and for exports. As of 1 January 1997 the trunk pipeline system had a total length of 12,500 km, with diameters between 550 and 1,000 mm. The system includes 250 gas distribution stations and 17 compressor stations. It is operated by the national gas transport company Uztransgaz,[10] which delivers gas to local distribution companies and to border points for exports.

10. The company also owns a section of the Omsk-Pavlodar-Chimkent-Chardzou oil pipeline which has not been in use since 1992.

The main pipelines in the system are:

- Bukhara region-Tashkent (1,221 km)
- Jarkak-Bukhara-Samarkand-Tashkent (755 km)
- Mubarek-Kagan (110 km)
- Shurtan-Mubarek (99 km)
- Kelif-Mubarek (274 km)
- Kelif-Dushanbe (221 km).

Uzbekistan's gas distribution network appears to be adequate for current production, which is principally for domestic use and limited exports to neighbouring countries. Uzbekistan's gas transmission lines have a rated carrying capacity in excess of 70 Bcm, though actual capacity is lower due to the poor operational condition of pipelines and compressor stations. It is estimated that 5 - 8% of gas moved by pipeline in Uzbekistan is lost through leakage. The network has the technical capacity to deliver more than 20 Bcm/year to other countries in Central Asia and to Russia, as well as to points beyond, via the Russian gas transportation system.

In 1996 total throughput of the Uztransgaz system was 69.9 Bcm. This included 20.3 Bcm of Turkmen gas transit, down from 48.4 Bcm in 1993 due to a cut-off in deliveries to Ukraine in response to non-payment problems. In March 1997 Turkmenistan ceased exports of gas to Ukraine, creating more pipeline space for exports of Uzbek gas to and via Russia.

There are two gas trunklines traversing Uzbekistan, both originating in Turkmenistan. One line travels north-east to south-eastern Kazakstan, while the other travels north-west to western Kazakstan and Russia. Turkmenistan's south-north line carries gas from the Dauletabad-Donmez field near the Turkmen-Afghan border, from the Shatlyk gas field east of Tedzhen, and from other fields northward to Khiva. It provides transportation for Uzbek and Turkmen gas north-westward along the Amu Darya to the Kungrad compressor station in Uzbekistan. From there most of the gas continues via Kazakstan to Alexandrov Gay in Russia, with some gas being sent northward on two aging pipelines to Chelyabinsk in the Russian Urals area. These pipelines could be used to export Uzbek gas to Europe provided that transit is agreed with Russia's Transneft and Kazakstan's Kaztransoil.

Intergas Central Asia, a subsidiary of Tractebel (Belgium), has a contract to run Kazakstan's gas networks, including pipelines transporting Uzbek and Turkmen gas to Russia and Europe and another to southeast Kazakstan. (For more details, see the Kazakstan chapter.)

Gas storage

Uztransgaz owns and operates four underground storage facilities: Poltoratskoye, North Sokhskoye, Mali Su-IV, and Gazli. These facilities have a combined design capacity of around 5.5 Bcm and in 1997 normally held around 4 Bcm of active gas. The Poltoratskoye facility, located on the border with Kazakstan, has a capacity of 340 - 350 million cubic metres. The North Sokhskoye facility has two sites, one in Uzbekistan and the other in Kyrgyzstan, with a combined capacity of 1.17-1.19 Bcm. The Mali Su-IV facility, leased in Kyrgyzstan, can hold about 50-60 million cubic metres of gas. In addition, an underground storage project at Khojabad is now under construction and should add about 900 Mcm of active capacity.

Natural gas consumption

In 1996 the industrial sector accounted for 57% of total domestic consumption. This included power plants producing both electricity and heat for consumers. The residential sector and consumer municipal services accounted for 34% and 9% of consumption respectively. Since 1991, residential sector consumption has nearly tripled, boosted by new supply lines to the rural population.

Household consumption of natural gas in Uzbekistan is fairly high on a per capita basis, especially considering that only one-third of households are supplied with gas. This is largely because household gas prices are heavily subsidized and there is virtually no metering. Uzbekneftegaz currently sells gas to local distribution companies (LDCs) for approximately 2,500 som per thousand cubic metres, or approximately US $31.65 at the official exchange rate. LDCs sell gas to the industry at approximately the same price, but charge households only about 900 som per thousand cubic metres. The difference is covered by government subsidies.

At the end of 1997, only about 2 - 3% of households and 8% of municipal buildings were equipped with meters.[11] The government has plans to contain household use of gas by requiring all new households to buy and install meters by 2000. Meters will also gradually be installed in existing houses. US-based Schlumberger donated 500 meters to the programme in 1997 and is contemplating creating a joint venture to assist in installing meters. The project has attracted some funds from Tacis and from the Uzbek government ($2 million). It is expected to save about 25% of gas used by households.

Measures, such as the installation of meters and improving the insulation of houses, are expected to partially offset the effect of projected strong population growth, moderating the growth in Uzbek gas demand. The scope for domestic demand growth is somewhat limited, since 80% of the country is already gasified. Indigenous supply is projected to grow at a somewhat faster rate than demand, resulting in modest net exports by 2000.

Table 7 Projected natural gas supply, demand and net exports: 1997 - 2010 (Bcm)

	Supply	Demand	Net exports
1997	50.0	46.9	3.1
2000	50.2	46.8	3.5
2005	53.9	50.9	3.0
2010	58.8	53.6	5.1

Source: IEA low case scenario

11. Moreover, much of gas consumed in Uzbekistan is burnt in power stations producing both electricity and heat for consumers, but only 1% of supplied heat passes through meters.

LPG

Uzbekistan currently consumes about 500 kt of LPG annually, most of which is imported from Russia. ABB Lummus Global, along with Japanese companies Mitsui and Nissho Iwai, are currently building a gas-chemical complex in Shurtan which will draw on gas produced at a local field. The facility will have a capacity to produce around 500 kt of LPG annually. The foreign companies are performing the work on the basis of a contract, under which ownership of the plant presumably will stay with the Uzbek government.

The high content of ethane, propane and butane in the gas from some Uzbeki fields makes it economically feasible to extract NGL for the purpose of producing polymer materials.

GAS TRADE

Uzbekistan has been a steady but modest gas exporter to neighbouring countries. Its gross gas exports fell from 10.3 Bcm in 1991 to 5.2 Bcm in 1996 due to lower demand in neighbouring countries and their inability to pay for the deliveries in hard currency. Some of these countries subsequently have run up large debts to Uzbekistan. Uzbekistan's exports of 5.17 Bcm in 1996 were equivalent to 11% of Uzbek gas production. They consisted of 3.25 Bcm to Kazakstan, 1.05 Bcm to Kyrgyzstan, 0.64 Bcm to Tajikistan and 0.23 Bcm to Turkmenistan.[12]

Table 8 Exports of Uzbek gas by country: 1991-1996 (Bcm)

	Kazakstan	Kyrgyzstan	Tajikistan	Turkmenistan	Total
1991	6.16	2.13	1.85	0.18	10.32
1992	5.57	1.81	1.62	0.16	9.16
1993	4.50	1.36	1.39	0.13	7.38
1994	3.00	0.88	0.98	0.10	4.96
1995	3.87	0.88	0.86	0.02	5.63
1996	3.25	1.05	0.64	0.23	5.17

Source: Market Intelligence Group

In August 1996 Uzbekistan and Kyrgyzstan reached an agreement under which Uzbekistan would continue pumping natural gas to its eastern neighbour until the end of 1996, and Kyrgyzstan would pay off its debt (over US $12 million) with sugar and wheat. Future gas deliveries are to be paid for half in hard currency and half in food supplies.

In December 1996 Ukraine and Uzbekistan signed a protocol for delivery of up to 10 Bcm of Uzbek gas to Ukraine in 1997, as well as for the transit of Turkmen gas destined for Ukraine via Uzbekistan through the year 2005. In return, Ukraine is to carry out geological

12. Market Intelligence Group, "Oil and Gas of Uzbekistan".

prospecting, build gas pipelines and engage in drilling in Uzbekistan. Uzbek gas does not physically reach Ukraine; instead, it is delivered to the border with western Kazakstan. Part of it remains there as a transit payment. The rest flows to Russia, where it is swapped for an equivalent amount closer to the Ukrainian border. The operation is arranged through Gaspex, a Cyprus-registered trading company.

In 1997, after previously cutting off supplies due to non-payment, Uzbekistan agreed to supply 1 Bcm of gas to southern Kazakstan. Almaty promised to pay off its US $26 million debt for previous deliveries in Kazak products and the transport of Uzbek goods through Kazakstan.

Proposed export pipelines for gas

The IEA low output scenario calls for Uzbekistan's exportable gas surplus to be around 3.5 Bcm by 2000. Existing pipeline capacity and demand could allow for potential exports of about 7 Bcm of gas to neighbouring Kazakstan, Kyrgyzstan and Tajikistan, but the current economic situation in those countries limits this option. Beyond 2000, further increases will be contingent on future exploration efforts and the development of new export pipeline capacity to other markets.

Increasing exports to other FSU countries via Russia will be difficult, since shipments must first pass through Kazakstan and because Russia's Gazprom is reluctant to displace competing Russian gas to provide the necessary pipeline capacity. To avoid dependence on Russia, Uzbekistan would need to build an alternative export pipeline. Projected exportable surpluses of gas are unlikely to be sufficient to support the construction of dedicated pipelines. The most cost-effective option may be to piggy-back on to pipelines proposed to move Turkmen gas to markets in Turkey, Pakistan, India or western China. (See Turkmenistan chapter.)

INVESTMENT

Recent investment activity in the oil and gas sector

Cumulative foreign investment in Uzbekistan's energy sector totalled US $10 million in 1994, US $545 million in 1996, and US $845 million in 1997. Perhaps less than US$20 million of this could be classified as foreign direct investment.

Most "foreign investment" projects in the Uzbek oil and gas sector are contracts with foreign firms that have been financed with the help of development loans from international financial institutions. In most cases the foreign contractor does not receive an equity share in the project. Supplier credits and foreign bank loans tend to be counted by the government as foreign investment along with foreign equity finance. However, it is only the latter that can really be regarded as a net additional source of finance for the country, since loans and supplier credits may merely crowd out loan finance for other sectors.

A brief review of some of the major projects involving foreign firms is provided below.

Uzmaloil

The only operating foreign equity investment in oil development is Uzmaloil, a $15 million project by Uzbekneftegaz and Malaysian-based Probadi. The project now produces around 20-30 tonnes of oil per year from the largely depleted Karaktay field using enhanced recovery methods. Another Malaysian company, Crest Petroleum, reportedly has a small related concession.

Kokdumalak field compression station

A US$162 million cyclic process compression station at the Kokdumalak field was completed in July 1997 by M.W. Kellogg, a subsidiary of Dresser Industries. It will facilitate the production of around 2.5 Mt of condensate per year by injecting high-pressure gas into the reservoir, raising condensate recovery from 30% to possibly as much as 70%. It should also extend the field's remaining production life from 13 to 57 years. However, there is some uncertainty as to how this complex retrograde condensate reservoir will perform with the re-injection of dry gas. The hydrocarbons produced are to be processed at the nearby purpose-built Karaulbazar refinery.

Karaulbazar refinery

The Karaulbazar refinery started operations in August 1997. This US$262 million project is the first major greenfield refinery built since the dissolution of the Soviet Union. Constructed by French company Technip and partly financed by government-backed loans from France, the US and Japan, the refinery processes condensate supplied from the Kokdumalak field through a new 94-km pipeline. The refinery is expected to reach full initial annual capacity of 2.5 Mt by early 1998. The possibility of doubling the new refinery's capacity to 5.0 Mt/year in the future was anticipated in the original plans.

Ferghana refinery

An agreement was reached with the European Bank for Reconstruction and Development to assist Uzbekneftegas in the rehabilitation of the Ferghana refinery. This US $200 million project is to be carried out by Mitsui over three years, according to a contract signed in December 1996. The upgrade is to improve the quality of products and boost production by 300 kt of diesel, 80 kt of petrol and 25 kt of sulphur. A desulphurisation plant (1.7 Mt capacity) is also to be built at the refinery to aid the switch in feedstock from low-sulphur Russian crude to high-sulphur crude from Kokdumalak.

Ferghana lubricant plant

Texaco has developed a US$12 million JV with Uzneftepererabotka to produce lubricants at an existing blending plant in the Ferghana refinery. Texaco contributed equipment to produce and fill lubricant containers and to test the quality of products. As the sole producer of lubricant base oil in Central Asia, the plant not only meets Uzbekistan's domestic needs, but also exports its products to neighbouring Turkmenistan, Kyrgyzstan, Tajikistan and Kazakstan.

Planned investments in the oil and gas sector

According to the Uzbek government, restructuring and modernisation of the oil and gas sector will require investments in excess of US $1 billion over the next few years.[13] Given the government's lack of financial resources, some of these funds probably will have to come from international lending institutions and foreign investors. The Uzbek government is now negotiating with potential foreign investors on participation in various oil and gas projects, several of which are discussed below.

Overall, the government has earmarked 32 new oil and gas fields for development, and another 18 for rehabilitation by foreign companies. It is currently exploring the possibility of creating production joint ventures with Pertamina, Unocal, Agip, Mobil, Shell and other foreign oil companies. These ventures likely will be based on service contracts, though some may be in the form of production sharing agreements.

In October 1996 Uzbekneftegaz signed an agreement with **Unocal** (US) and **Delta** (Saudi Arabia) on joint research in exploration, development and production of oil and gas in the Ferghana basin and in the Kashkadarya region near Beshkent. The study will examine the oil and gas reserves in these regions and may lead to a contract for development and marketing of associated hydrocarbons.

In 1997 Uzbekneftegaz signed a US $60-million contract with **BSI Industries** (US) to develop the Khodzhaabad gas field in the Andizhan region. The contract is for the construction of an underground storage facility that includes gas injection compression and 56 wells, separation, a refrigeration system, gas heating and metering. The start-up is scheduled for July 1998.

Enron Oil and Gas International (US) is negotiating E&P rights to develop 11 gas fields in Bukhara-Khiva oblast (Surkhandarya and Amu Darya basins) in southern Uzbekistan. Reserves in these fields are estimated by Uzbek officials at around 170 Bcm of gas and 600 Mb of condensate, sufficient to ensure a production life of about 30 years. The fields are expected to produce around 1.5 Bcm/year initially and peak at 6 Bcm/year. Initial investment in the project is expected to be around US$300 million, while total investment could reach US$1.3 billion over the next 20 years.

Bakrie (Indonesia) signed two memorandums of understanding with the Uzbek State Property Committee; one to invest US$ 600 million under a service contract in oil and gas well workovers and other field rehabilitation projects, and another to build a US$ 300 million fertiliser plant in Kashkadarya province.

ABB Lummus Global, Mitsui and **Nissho Iwai** are planning to build a gas-chemical complex in Shurtan which will draw on gas produced at the local field. The companies will finance US$600 million of the project, with another US$400 million to be provided by Uzbekistan. The facility will have the capacity to produce 500 kt of LPG annually, including 125 kt of polyethylene, 140 kt of ethylene and 235 kt of ethene and other products.The project is to be done on a turnkey basis.

13. Based on official government estimates of oil and gas reserves.

Uzbekneftegaz is seeking a foreign partner to build a new sulphur extraction plant at Kokdumalak in order to boost the field's gas production potential by 6 Bcm.

Privatisation

With the adoption of the law on Competition and Restriction of Monopoly Activity in January 1997, there are no longer any legally protected monopolies in the energy sector. However, the sector is almost entirely dominated by de facto monopolies such as Uzbekneftegaz.

The Act on Denationalisation and Privatisation is to be implemented so as to allow individuals and corporate bodies of other states to acquire divested and privatised entities and their shares under procedures to be adopted by the Cabinet of Ministers or a body authorised by it. The State Property Committee is to determine the range of buyers and the distribution of shares among them.

The Supreme Council (Oli Majlis) has published a list of types and categories of strategic entities and assets not subject to denationalisation or privatisation. A second list contains facilities and entities, including in the energy sector, which are to be divested and privatised subject to a future decision of the Cabinet of Ministers.[14]

In 1994 and 1995 certain Uzbekneftegaz entities (mainly in distribution and construction-maintenance) were restructured. All departments related to drilling were converted into "open joint stock companies" in 1996 as a first step towards privatisation. During this first phase of corporatisation/privatisation, the state is to maintain a controlling interest. Pipeline transportation will remain a de facto state monopoly with no plans for corporatisation or privatisation in the near future.

As of the beginning of 1998, over 80 entities in the oil and gas sector (mainly engaged in services) had been restructured, including 77 as joint stock companies, four as leasing entities and two as co-operatives). Transfer into private ownership of the newly created corporate entities is not envisaged in the foreseeable future. Petrol stations are an exception; so far about 50% of these have been auctioned to private national investors. By 1999 oil-production entities and refineries are to be turned into joint stock companies.

Legislation relevant to oil and gas investment

Important legal and regulatory developments affecting investment in the oil and gas sector include the following:

Enterprise Tax Law of 1991

The Enterprise Tax Law of 1991 has been amended several times to afford certain benefits to foreign companies and joint ventures with foreign firms, including the right to pay only 25% of the standard income tax rate (up to 35%) during the first year of operation and only 50% during the second year.

14. Ruling of the Oli Majlis, 31 August 1995, concerning certain aspects of denationalisation and privatisation of individual entities and assets.

Access to land

According to the Law on Property, the government is the exclusive owner of land in Uzbekistan, as well as of the subsoil and in-land waters. Exceptions are granted in cases and on terms and conditions provided by specific legislation. According to Article 11 of the Law on Land, land may be granted or leased to joint ventures and organisations with national and foreign interests if authorised by the Cabinet of Ministers.

Protection of foreign investment

In May 1994 Uzbekistan's parliament enacted the Law on Foreign Investment and Guarantees for Activities of Foreign Investors, which reiterates and in some cases extends guarantees on the protection of foreign investments provided by similar laws of 1991 and 1992. These guarantees include protection against expropriation (except in extraordinary circumstances, and provision for compensation in the event); the right to repatriate profits; a ten year exemption (with some exceptions) from new legislation having a negative effect on operations; licensing and tariff exemptions for exports of a joint venture's own production and for imports of equipment to meet production needs; and access to foreign arbitration.

The Law on Foreign Investments stipulates, inter alia, that the legal treatment of foreign investments shall not be less favourable than the treatment of investment of similar legal and physical persons of Uzbekistan, and that additional privileges may be given to foreign investors making investments in priority sectors and regions.

Newly established enterprises are classified as "enterprises with foreign investments"(subject to registration by the Ministry of Justice and its territorial bodies) if they meet the following conditions:[15]

- the authorised fund of the enterprise is more than US$300,000;
- one of the partners of the enterprise is a foreign legal entity; and
- the share of the foreign investments constitutes not less than 30% of the authorised capital of the enterprise.

The Decree of 31 May 1996 on Additional Measures to Stimulate Establishment and Activities of Entities with Foreign Investment requires an information system for foreign investors. One of the parties responsible for information dissemination is the Foreign Investment Agency (FIA), founded with the assistance of UNIDO in August 1995. Responsibilities of the FIA include:

- maintaining a data base on activities of enterprises with foreign investment and investment offers;

15. Decree of the President of 30 November 1996 on additional incentives and benefits granted to entities with foreign investments.

- promoting such offers;
- resolving issues arising during their implementation; and
- advising the government regarding improvements to the general investment climate.

Uzbekinvest, a local export/import insurance company, was established by the government to cover political and commercial risks. Uzbekinvest and the US financial group AIG Inc. have formed a joint insurance company with headquarters in London to cover political risks, including civil unrest and expropriation, and another with headquarters in Tashkent to cover commercial risks.

Petroleum licensing

The Cabinet of Ministers establishes the procedure, terms and conditions for allocating subsoil rights to foreign legal and physical persons and entities with foreign participation in the area of exploration, extraction and processing of raw materials (Law on Subsoil, 1994, Article 8). In order to explore for, produce, refine or process or sell oil or gas, an investor must obtain a licence in accordance with the procedure prescribed by the Cabinet of Ministers (Ruling of the Cabinet of Ministers No. 215 of 19 April 1994).

Concessions may be granted to foreign investors on the basis of tenders and auctions and, only in exceptional cases, on the basis of direct negotiations between the granting body and an investor.

Taxation

Taxation in Uzbekistan is based on the Tax Code of 24 April 1997. Income (profit) of legal entities is subject to taxation up to the rate of 35%. The Cabinet of Ministers may establish reduced rates of tax on income for legal entities with foreign investments. Dividends and interest paid to both legal entities and natural persons are taxable at the payment source. Government loans and dividends and interest from other government securities are exempted from taxation.

Several types of legal entities are exempted from income tax. However, this exemption does not extend to legal entities producing raw goods for export, including oil, oil products, electric power, gas condensate and natural gas.

Other relevant taxes include:

- **VAT (20%):** the rate for exported goods and services is zero, except for shipments to states which tax goods and services exported to Uzbekistan.
- **Property tax** for legal entities (4%): the rate of property tax of natural persons is imposed in accordance with rates approved by the Cabinet of Ministers.

- **Land tax:** rates established by the Cabinet of Ministers. Legal entities and natural persons leasing land pay rent to the budget instead of the land tax.
- **Tax on subsoil use:** rates established by the Cabinet of Ministers.
- **Ecological tax** (1%).
- **Water resources use tax:** rates established by the Cabinet of Ministers.

With a view towards greater internal consistency and compatibility with international standards, the government is undertaking a review and revision of the tax code.

Uzbekistan inherited the accounting system of the Soviet Union, though is currently in the process of adopting generally accepted international accounting standards.