Regional: The Oil and Gas Sector in Transition: Challenges and the role of the EBRD – Energy Operations Policy

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ABBREVIATIONS

ACG	Azeri, Chirag, Guneshli (oilfields off the coast of Azerbaijan)
bbl(s)	barrel(s)
bcm	billion cubic metres
BP	British Petroleum
bpd	barrels (of oil) per day
BPS	Baltic Pipeline System
BTC	Baku-Tbilisi-Ceyhan (oil export pipeline)
CDIAC	Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory
CEE	Central and Eastern Europe
CEP	Caspian Environment Programme (CEP)
CGES	Centre for Global Energy Studies
CIS	Commonwealth of Independent States
CNPC	China National Petroleum Corporation
DFID	Department for International Development
EBE	Eastern Bloc Energy
EBRD	European Bank for Reconstruction and Development
EITI	Extractive Industries Transparency Initiative
EOPP	Energy Operations Policy
ERIN	Environment and Natural Resources Information Network
EU	European Union
FSU	Former Soviet Union
FYROM	Former Yugoslav Republic of Macedonia
GGRF	Global Gas Flaring Reduction Initiative aka. Global Initiative on Natural Gas Flaring Reduction
GHG	Greenhouse gases
IFI	international financial institutions
mbpd	million barrels (of oil) per day
mn	million
mn T/yr	million metric tons per year
NGL	natural gas liquids
NGO	Non-governmental organisation
OCE	Office of the Chief Economist (at the EBRD)
OECD	Organisation for Economic Co-operation and Development
ONGC	Oil and Natural Gas Corporation (of India)
OPEC	Organisation of Petroleum Exporting Countries
PSA	production sharing agreement
SCP	South Caucasus Pipeline (gas)
SEIC	Sakhalin Energy Investment Company
UNEP	United Nations Environment Programme
VLCC	Very large crude carrier
WBG	World Bank Group
WTO	World Trade Organisation

DEFINED TERMS

The Bank	The European Bank for Reconstruction and Development

EXECUTIVE SUMMARY

The oil and gas industry environment, both globally and more specifically in the EBRD's countries of operation has changed significantly since the Bank's Natural Resources Policy was last updated in 1999. At the end of the 1990s, the world was emerging from an oil price shock that had seen Dated Brent crude tumble to $10/bbl, Russian oil production had fallen to and stabilised at around 6 mbpd, little more than half its Soviet-era peak, and it was generally assumed that only through massive foreign investment in the oil and gas industries of the CIS countries could further decline be averted. Five years on, oil prices stand at more than $50/bbl, with little immediate sign of them falling, Russian oil production has surged by more than 50% to exceed 9 mbpd with relatively little involvement by foreign oil companies and oil production in Kazakhstan and Azerbaijan is beginning to have a significant place on international markets. Russia has taken steps to re-orient its oil exports to Russian ports instead of those in neighbouring countries, while on the Caspian Sea region international crude oil and natural gas export pipelines have been built and more are under construction.

At the same time, global concern over greenhouse gas emissions has risen up the political agenda, resulting in Russia's ratification of the Kyoto Protocol, which subsequently came into force in February 2005. The social and environmental impacts of energy projects, transparency of payments to host governments and management of oil and gas revenues have also risen up the political agenda, resulting in a flurry of initiatives, including the Extractive Industries Transparency Initiative, Publish What You Pay and the Global Gas Flaring Reduction Initiative. These initiatives increasingly define the framework in which the Bank is required to operate in the energy sector, although they are not always popular with host governments that may see them as unwanted outside interference.

The Bank has built up a wealth of experience in operating in all stages of the oil and gas supply chain and still has a vital role to play in this area in the future. The Bank is seen as providing both comfort to and a lead to commercial banks through its pioneering of project-based loans to transition countries. As the environment in which it operates has shifted, so too have the opportunities for the Bank to pursue its transition objectives in the oil and gas sector.

The largest Russian oil companies are now generally able to raise finance on the international commercial lending markets, reducing the need for EBRD involvement in all but the largest of their projects. However, the Bank has an important role to play in moving foreign lending down the hierarchy of Russian companies, embracing some of the smaller players and encouraging the commercial banks to do likewise. The oil industry in Russia has become much more competitive over the past five years, the re-nationalisation of Yuganskneftegaz notwithstanding. The same is not true of the Russian gas industry which remains monopoly-controlled through state-owned Gazprom, other gas producers remaining dependent upon Gazprom for access to gas pipelines and markets. It is unlikely that the structure of the Russian gas market will be susceptible to external pressure for change, so the Bank should, perhaps, support the activities of second-tier gas producers in Russia, helping to build up a viable independent gas sector. The Bank's leverage may help such companies secure guaranteed access to pipelines and markets. Other gas projects that the Bank might become involved in are the proposed offshore gasfield developments and associated LNG terminals, which will require huge investments and probably involve foreign, as well as Russian, partners. In the Caspian Sea region, as in Russia, the Bank's key role in upstream oil and gas projects could well be in supporting smaller players, helping to create a vibrant 'independent' oil sector populated by smaller companies.

Several potential opportunities exist for the Bank to become involved in oil and gas transportation projects, particularly in the Balkans where various pipelines have been proposed to bypass the environmentally sensitive Turkish Straits. These projects still have to overcome political hurdles before they can move forward, but it is likely that one or more such pipelines will be built in the next five to ten years.

Downstream, the growing global demand for light, sweet products (ultra-low sulphur transportation fuels) opens up opportunities for the upgrading of refining capacity in the Bank's countries of operation to meet tightening product specifications in most export markets. Such investments would have a beneficial local impact, improving the quality of oil products sold on the local market.

Since the Bank reacts to requests for its involvement, rather than actively seeking projects in which to invest, it does not make sense for it to impose quotas on itself for particular types of project. The Bank is under external pressure to promote renewable energy projects in favour of fossil fuel projects, but should resist pressure to impose a 'renewable energy quota' on its lending. The renewable energy industries in the Bank's countries of operation are in their infancy, at best, and any such quota would only reduce the Bank's involvement in energy projects generally. Perhaps the Bank could consider a renewable energy investment growth target, similar to that adopted by the World Bank. It might also consider promoting the use of renewable energy technology in and around the hydrocarbons projects that it supports.

The Bank should also sign up to the Global Gas Flaring Reduction Initiative and make adherence to the principles of that initiative a pre-requisite for its involvement in oil and gas projects. It should take a similar stance with regard to transparency, requiring project partners and host governments to adhere to the principles of the Extractive Industries Transparency Initiative.

The oil and gas sector plays a major role in the economies of the transition countries and the Bank needs to remain actively involved in the sector. It has a vital role to play not just in mobilising finance to help the economic development and transition of these economies, but also in ensuring that the projects that it supports operate to the very highest standards environmentally, socially and in terms of transparency and governance. The Bank, along with other IFIs and pressed by NGOs, has been at the forefront in setting the agenda for the regulation of foreign investment in transition countries. It should continue providing a model for others to follow and a benchmark for them to be measured against.

1 INTRODUCTION

1.1 BACKGROUND TO THIS REPORT

This background report on **Oil and Gas in Transition – Challenges and the role of the EBRD** was commissioned by the Office of the Chief Economist (OCE) at the European Bank for Reconstruction and Development (EBRD) as part of the process of updating the bank's Energy Operations Policy. The new Energy Operations Policy will integrate the former Natural Resources Policy (last updated in 1999) and the Energy Policy (last updated in 2000).

In developing a new Energy Operations Policy (EOPP), the Bank is seeking to take account of the evolved dynamics, both within the Bank's countries of operation as well as globally within the sector, that have occurred since the last policies for Natural Resources and Energy were issued. The global influences include a dramatic shift in the prices of both oil and gas, a clearer definition of environmental issues and an increased focus on factors influencing climate change. In the countries of operation, these new dynamics stem from: the shift in requirements that has resulted from significantly higher oil and gas prices; increased transition achieved; and the challenges that countries continue to face in most areas, particularly in the continuing lack of transparency, deteriorating infrastructure, high energy intensity, deficient nuclear safety, and inadequate energy transportation (particularly cross-border), which the Bank will continue to address.

The Bank also has greater experience now which will be used to review its approach to these matters.

The activities covered under the EOPP include:

- Oil (covering the whole cycle from production to transportation, oil refining, oil product and petrochemical plants), and natural gas (production, transportation, and petrochemicals distribution), and coal mining;
- Energy conversion, transportation, distribution and consumption; i.e., power generation (including fuel choice issues and nuclear safety), power transmission and distribution, and heat generation and distribution;
- Energy efficiency and the demand side, covering utilisation of power, heat, and gas including energy consumers as well as energy utilities, including general industry operations to achieve gains in efficiency as well as operations by Financial Institutions (e.g. trade facilitation operations) that support renewables and energy efficiency projects; and
- Captive, inside the fence assets of companies the Bank has a relationship with, and also energy projects done through financial intermediaries.
- Although shipping or rail transportation is covered by the Transportation Policy and District Heating is covered under the Municipal and Environmental Policy, the policy paper will make detailed cross-references to the energy related activities covered by these policies.

1.2 Scope of this report

This background report will focus on issues in the oil and gas sectors, covering the upstream (exploration and production), midstream (refining and transportation) and downstream (distribution and consumption).

According to the Terms of Reference, this background paper is to lay out:

(i) The main energy and broader business environment issues facing the EBRD's countries of operation, distinguishing specific issues and country groups as necessary (e.g., energy or electricity exporters, advanced or early transition countries, etc.);

(ii) the main developments over the last five years (since the publication of the previous Natural Resources Strategy), both within the region (e.g., the increasing role of Russia as an energy supplier, developments in the Caspian region, trends in reforms across the dimensions of regulation, private sector involvement and competition) and in terms of global trends (e.g., issues in emerging markets, the Kyoto Protocol, commodity prices, the increased global role of LNG, relations between the oil and gas producing countries and the European Union through energy supply, the impact of WTO accession).

(iii) remaining challenges and opportunities for the oil and gas sector that would inform the Bank's "vision" and overall approach; and

(iv) the potential role of the EBRD as a private sector-oriented, project-based financial institution.

The key issues to be explored will include, *inter alia*:

(i) What are the best ways to promote energy efficiency and energy conservation, both on the supply and demand side?;

(ii) What is the scope for renewable energy, and what should be the approach of EBRD with regard to fuel mix, taking into account both environmental concerns and perceptions of security of supply in the local, national, and regional contexts?

(iii) What lessons can be drawn from experience to date on how to better support reform, including the key dimensions of promoting commercialisation, private sector involvement, regulatory reform and conditions required to enhance competition (including third party access to pipeline networks) ? How can financial institutions like the EBRD further support the uptake of such reform measures in the countries of operation?

(iv) How can the Bank best encourage reform in the gas sector in Russia. Should the Bank focus its efforts on encouraging the development of the independent gas producers sector, or on encouraging reform of Gazprom itself? Are there parallels in other counties or sectors?

(v) How, if at all, should the EBRD best assist in enhancing transparency of contracts (e.g. PSAs), revenue flows and revenue management?

(vi) How can policy dialogue between International Financial Institutions (IFIs) and local authorities be improved to overcome the specific transition challenges and support the development of competitive energy markets?

(vii) What is the scope for, and what are the risks of projects for regional integration, cooperation and trade. What mechanisms can EBRD employ to reduce associated risks?

(viii) How can oil and gas projects facilitate transition and economic development, and what role can the Bank play to transpose the full benefit to consumers?

(ix) What are the main environmental issues facing the region in the oil and gas sector? In particular, should reducing gas venting and flaring be seen simply as a desirable side benefit of modernisation, or a key policy goal for the Bank? How can the Bank best ensure appropriate utilisation of associated gas, and would it be useful if the Bank were to associate itself with initiatives such as the Global Gas Flaring Reduction initiative?

(x) What are the main social issues in the oil and gas sector, and how should they be addressed by EBRD (e.g., minimising project footprints, community development programmes, displacement and relocation, risks to traditional economic activity, environmental and social impact assessments)?

The report reflects the views of the author and not necessarily those of the Bank or its staff. The issues addressed in the report have been determined through discussion with members of the Bank's staff and as a result of information acquired through the author's attendance at the public consultation meeting held by the Bank in London on the 19th of January 2005 as well as verbal feedback from similar public consultation meetings held in Moscow and Sofia.

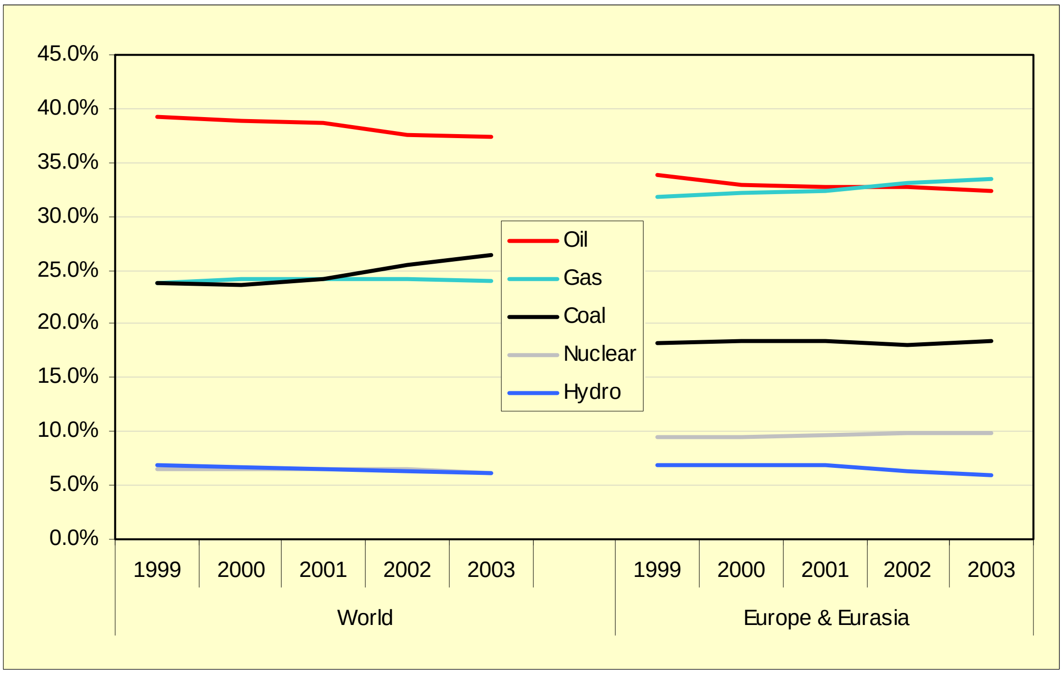
2 CHANGES IN THE OIL AND GAS SECTOR

2.1 CHANGES IN THE INTERNATIONAL ENERGY SECTOR 1999-2005

The global oil and gas industry has undergone fundamental and dramatic changes since the Bank last reviewed its Natural Resources Policy in 1999, which have affected the Bank's countries of operation in a variety of ways.

- Oil and gas prices have soared and the current expectation for future oil prices is very uncertain.
- China, and to a lesser extent India, have emerged as major centres of oil demand growth.
- Oil's share of primary energy demand (excluding traditional, non-commercial fuels) fell between 1999 and 2003 from almost 40% to just over 37%, while in Europe and Eurasia it slipped from 34% to 32% over the same period (comparable figures for 2004 demand will be published in June 2005).
- Natural gas's share of global primary energy has remained stable at around 24%, but in Europe and Eurasia its share of primary energy demand rose from 32% to 33.5%.
- Hydroelectricity, the only statistically significant source of renewable energy, saw its share of primary energy demand slip from 7% to 6%, both globally and in the Europe and Eurasia region.
- Rising demand for light products and stricter product quality specifications have put pressure on the global refining industry, requiring significant investment in upgrading, but yielding rewards for those refineries able to supply products that meet the tougher specifications.

Figure 1: Shares of primary energy demand by fuel

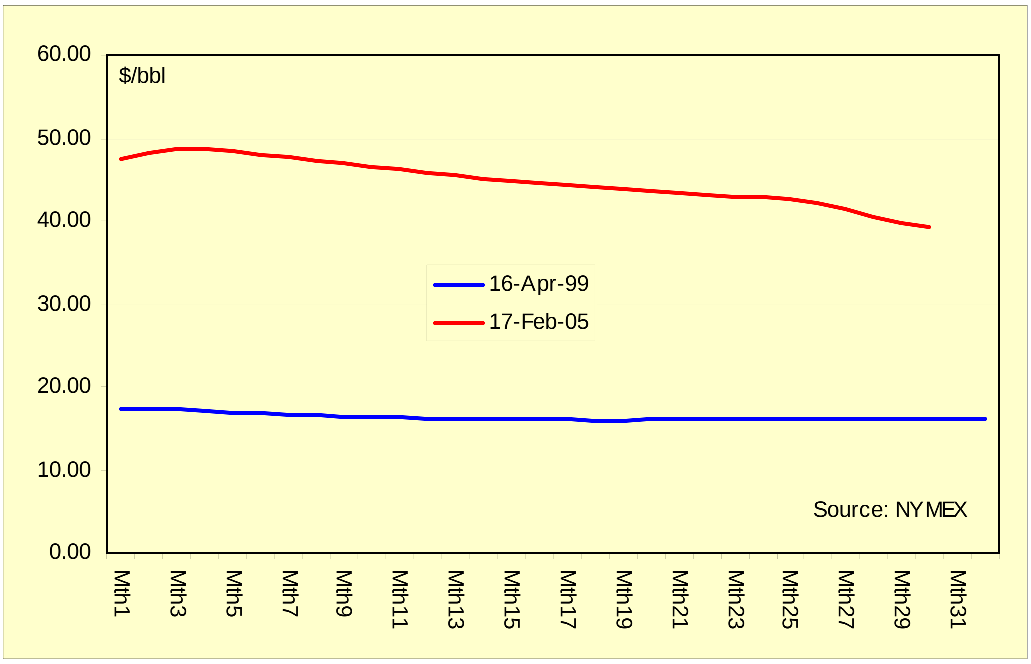


2.1.1 Soaring oil and gas prices

At the time of the last revision of the Bank's Natural Resources Policy oil prices had recently fallen to a level of around $10/bbl, having spent most of the previous decade between $15/bbl and $20/bbl. Most oil price forecasts at that time envisaged a protracted period of low oil prices with a slow recovery towards the upper teens. In the five years since the last policy revision the outlook for oil and gas prices has changed completely. Oil prices are now pushing $50/bbl and could rise further in the short term, but there is huge uncertainty over their longer-term future, which complicates the planning for large, long-term, capital-intensive projects.

The rise in prompt oil prices (those paid for oil to be delivered within the following month) has been accompanied by an upward shift in the entire forward curve and it is now possible to buy and sell WTI crude oil for delivery almost three years into the future at around $40/bbl. In April 1999, the same WTI crude could be bought and sold 32 months ahead for just over $16/bbl. It is noticeable that oil prices have moved up dramatically all along the forward curve, but the slope of the curve has also steepened, with a much larger discount for future oil relative to supplies for immediate delivery. This prompt premium reflects the current tightness in the oil market in an environment where oil demand growth is outstripping incremental supply, while commercial oil inventories are low.

Figure 2: Oil prices on the WTI forward curve



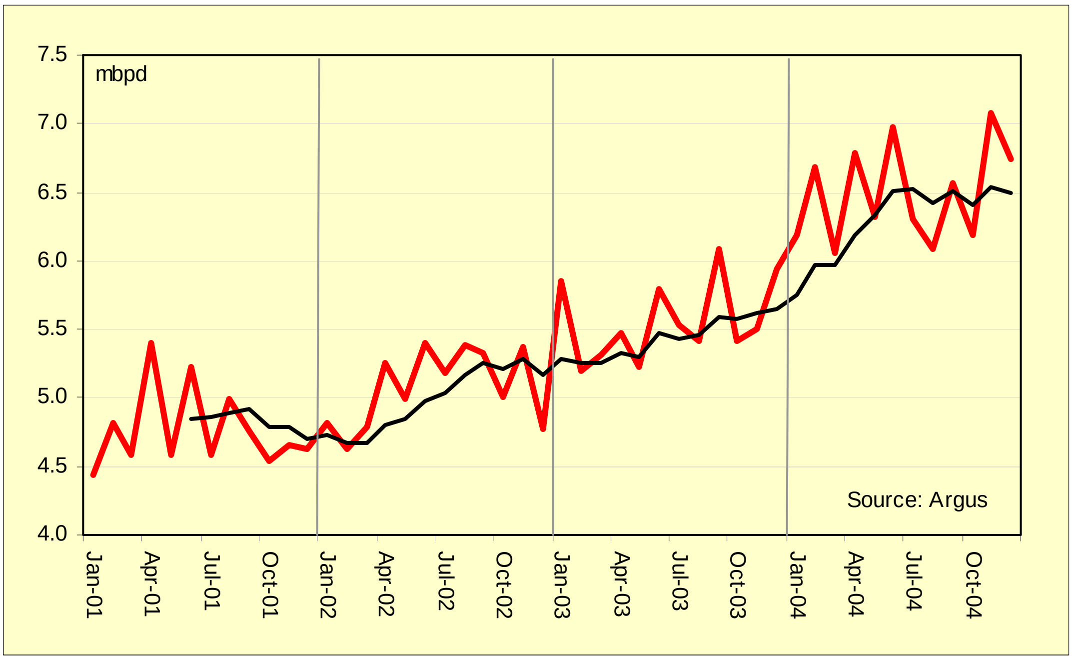
The long-term futures price is not the price that oil companies base their investment decisions on, however. Oil company spending plans have not risen in line with oil prices and it is noticeable that although the major privately-owned oil companies have reported record profits for 2004, almost all of them saw falling levels of oil production and were unable to replace reserves through drilling. The companies also chose to return billions of dollars to their shareholders through higher dividends and share buy-back schemes, suggesting a lack of big new upstream projects in which to invest.

Oil company investment decisions are still being based on a long-term oil price that is well below current prices. While most companies have increased the oil price used in their decision-making process from the $14/bbl or so that was common at the end of the 1990s, few seem to have raised it much beyond $20/bbl, perhaps indicating that they are not confident that the current level of oil prices will persist. Many still remember the experience of the early 1980s, when oil prices were high, OPEC was dominant and forecasters were predicting $100/bbl-oil by 1990. By 1986, following almost half a decade of falling global oil demand, Saudi Arabia had been forced to reduce its oil production from more than 10 mbpd at the start of the decade to an average level of just 3.6 mbpd in 1985 and the price of Brent crude oil subsequently tumbled from $27.5/bbl on average in 1985 to just $14.3/bbl in 1986. Other than during the Iraqi invasion of Kuwait in 1990, oil prices did not rise much above $20/bbl again for the next decade and a half.

2.1.2 China's energy demand

China's oil demand has soared in recent years and shows little sign of slowing down, in spite of the government's attempts to reduce the rate of economic growth. Growing Chinese oil demand has undoubtedly contributed to the dramatic rise in oil prices experienced in 2004, but the longer-term implications of the country's growing energy consumption and, more importantly, its growing dependence on imported oil and gas are of greater long-term significance.

Figure 3: China's apparent oil demand



China became a net oil importer in 1994 and in the decade since then imports have risen to account for around 50% of the country's oil consumption. By 2030, China expects imported oil to meet 75% of demand and the country is reacting in a number of ways to this growing dependence on imported oil. The Chinese response seeks both to secure and diversify its sources of imported oil, to boost domestic production of oil, to increase the market share of locally-produced coal and to reduce the rate of oil demand growth through greater efficiency.

China's attempts to secure and diversify its sources of imported oil have seen an aggressive campaign by the China National Petroleum Corporation (CNPC) to secure upstream projects in foreign countries. By the beginning of 2005, CNPC was involved in or negotiating upstream oil and gas projects in eleven countries (Algeria, Azerbaijan, Chad, Ecuador Indonesia, Kazakhstan, Niger, Peru, Russia, Sudan and Syria) and was actively seeking projects in others, including Egypt, Uzbekistan and Venezuela.

India has begun to follow a very similar strategy, with state-owned ONGC Videsh becoming increasingly active internationally. The company has interests in Angola, Australia, Cote d'Ivoire, Iran, Iraq, Libya, Myanmar, Russia, Sudan, Syria and Vietnam and is actively pursuing other opportunities.

These Asian oil companies have very different priorities from those of their Western counterparts, whose investment decisions are based on considerations of return on investment. For the Asian companies, who are tools of their home governments' national energy policies, access to crude oil supplies is a more important consideration than project profitability. Both companies are becoming increasingly successful competitors for upstream oil and gas projects and their roles in the oil and gas industries of Russia, Azerbaijan and Kazakhstan are expected to increase.

2.1.3 Oil's share of primary energy demand

Although oil's share of primary energy demand has slipped both globally and in the Europe and Eurasia region, it remains a major energy source and will continue to do so for the foreseeable future. In 2003, oil was overtaken by natural gas as the main provider of primary energy in Europe and Eurasia, reflecting the impact of the 'dash for gas' that gripped Western Europe at the end of the 20th century.

Oil demand in the Europe and Eurasia region has stabilised at 19.5-20.0 mbpd since the mid-1990s after the collapse in FSU consumption. The dramatic increase in Russian oil production since the beginning of the current decade and the resulting surge in its oil exports to Europe have not boosted oil consumption, but has rather offset declining oil production in the North Sea and displaced imports from elsewhere, principally the Middle East.

Some have suggested that recent and future rises in oil production from Russia and the Caspian Sea region would exert downward pressure on global oil prices, spurring oil demand growth and increasing the volume of greenhouse gases emitted as a result of oil consumption. The CGES does not believe this assertion to be true. Global oil demand increased by 8.25 mbpd between 1998 and 2004. Over the same period oil production in the FSU rose by nearly 4 mbpd and non-OPEC production outside the FSU rose by around 1.4 mbpd. The other 3 mbpd of incremental global oil demand over this six-year period was met by rising OPEC oil production (including an extra 1 mbpd of OPEC NGL production). Had FSU oil production not grown as it did, OPEC output would have risen faster. Indeed, it could be argued that the dramatic increases in FSU oil production in the early years of this decade have contributed to the current high oil prices. Sluggish global oil demand growth and the rapid increase in non-OPEC oil production (led by the FSU) resulted in three years (2000-2002) during which OPEC faced a year-on-year drop in the demand for its oil. In this environment, Saudi Arabia and other major Middle Eastern oil producers held back on investments that they would otherwise have made in expanding their oil-production capacity. The surge in oil demand in 2003 and 2004 left the world short of spare oil-production capacity and oil prices have risen as a result.

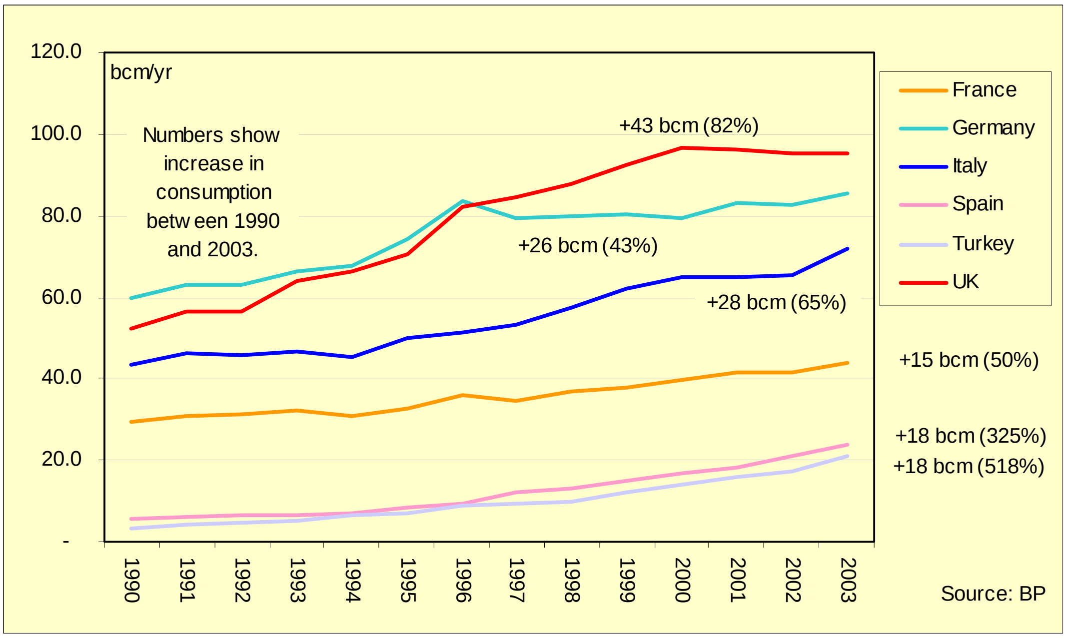
Future increases in oil production from Russia and the Caspian Sea region are not expected to have a material impact on global oil prices, since this production will supplant output capacity that would otherwise increase in the Middle East. The investment plans of Saudi Arabia and other Gulf oil producers are based, in part, on the perceived future demand for their oil and production increases expected elsewhere in the world are factored into this decision-making process. New oilfields being developed in Russia and in and around the Caspian Sea generally have long-lead times (the first big increase in production from Azerbaijan's ACG fields, for example, is coming more than 10 years after the PSA was signed in 1994, while year-round production from Russia's Sakhalin 2 project is not expected until 2006, again more than a decade after the contract was signed). In contrast, Saudi Arabia brought the 500,000 bpd Shaybah oilfield into production in 1999, just four years after awarding the project management contract.

Furthermore, it could be argued that the shorter shipping distances for crude oil from the FSU to markets in Europe and North America (the distance from Ceyhan to New Orleans is approximately half that from Ras Tanura in Saudi Arabia to the same destination) makes the transportation of FSU oil to customers less environmentally damaging than the delivery of the same quantity of Middle Eastern oil.

2.1.4 The growing importance of gas in Europe

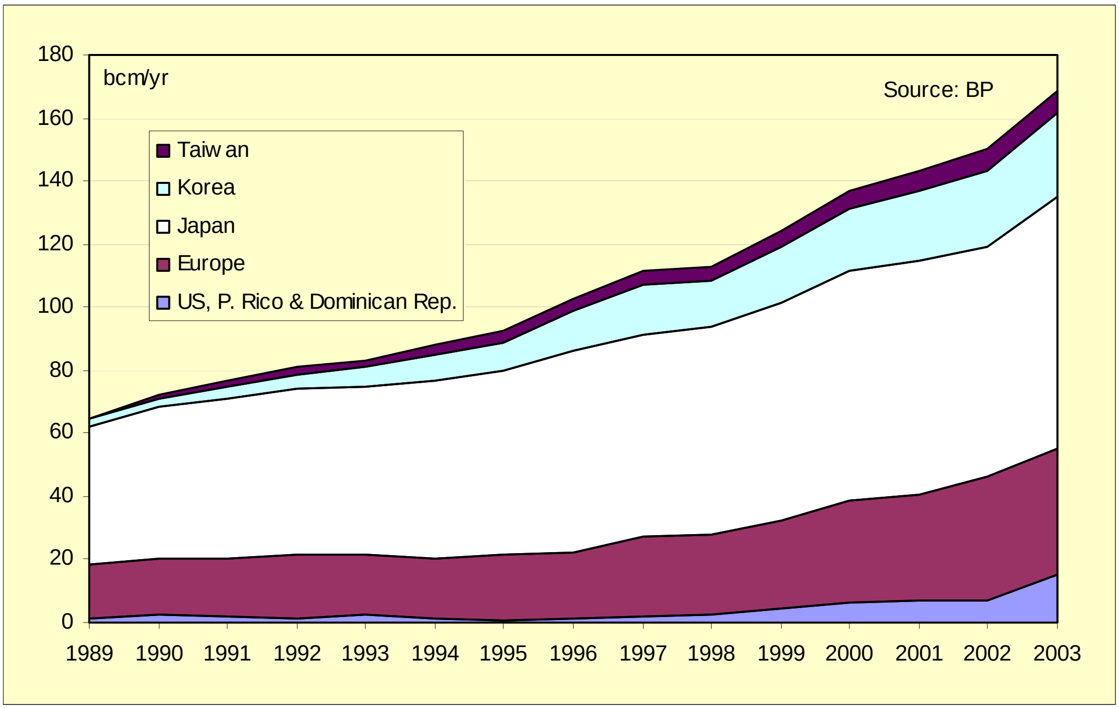
During the 1990s natural gas became the fuel of choice for new power generation capacity in Western Europe, leading to huge increases in natural gas consumption among key regional consumers. Total natural gas consumption in Western Europe and Turkey rose by 176 bcm/yr between 1990 and 2003, an increase of almost 70%. In contrast, oil demand in the same group of countries rose by just 11% over the same period. Russia's natural gas exports to the same group of countries rose by 25 bcm/yr (38%) over the period and are set to grow further in the future as supplies from the North Sea peak.

Figure 4: Natural gas consumption in selected European countries



The dash for gas is spreading from Europe to North America and the Asia Pacific region in response to growing concerns over global climate change. In these regions, gas import pipelines are already operating at capacity and future incremental delivery is likely to arrive in the form of LNG, at least until new pipelines are built. Global LNG trade rose from 72 bcm in 1990 to 169 bcm in 2003, growing at an annual average rate of almost 8% after 1995.

Figure 5: Global LNG trade (1989-2003)



Russia has embarked on a policy of developing an LNG export capability with the intention of supply liquefied gas to markets in Asia and North America. First supplies are scheduled to come from the Sakhalin 2 project by 2007, while Gazprom intends to develop its own LNG export project based on the Shtokman field in the Barents Sea. The company hopes to form a consortium with international oil and gas companies by the middle of 2005 with the intention of delivering first gas supplies in 2010 or 2011. Foreign companies hope to be able to conclude a production sharing agreement (PSA) for the project and Gazprom's Deputy CEO Alexander Ryazonov is reported as saying that 'Russian officials say they'll support a PSA for this project'[1], despite the general antipathy towards such contracts. The first phase of the project, targeting output of 30 bcm/yr, is expected to cost some $10 bn.

2.1.5 Hydropower struggles to keep pace

Globally, hydroelectric power has failed to keep pace with primary energy demand growth. As a result its share of the global primary energy demand has slipped from 7% to 6%. Hydroelectricity is, at present, the only statistically significant form of renewable energy on a global scale. The fall in its market share is the result of a backlash against

[1] 'Gazprom: LNG consortium to be formed by mid-2005', Dow Jones, 14th February 2005.

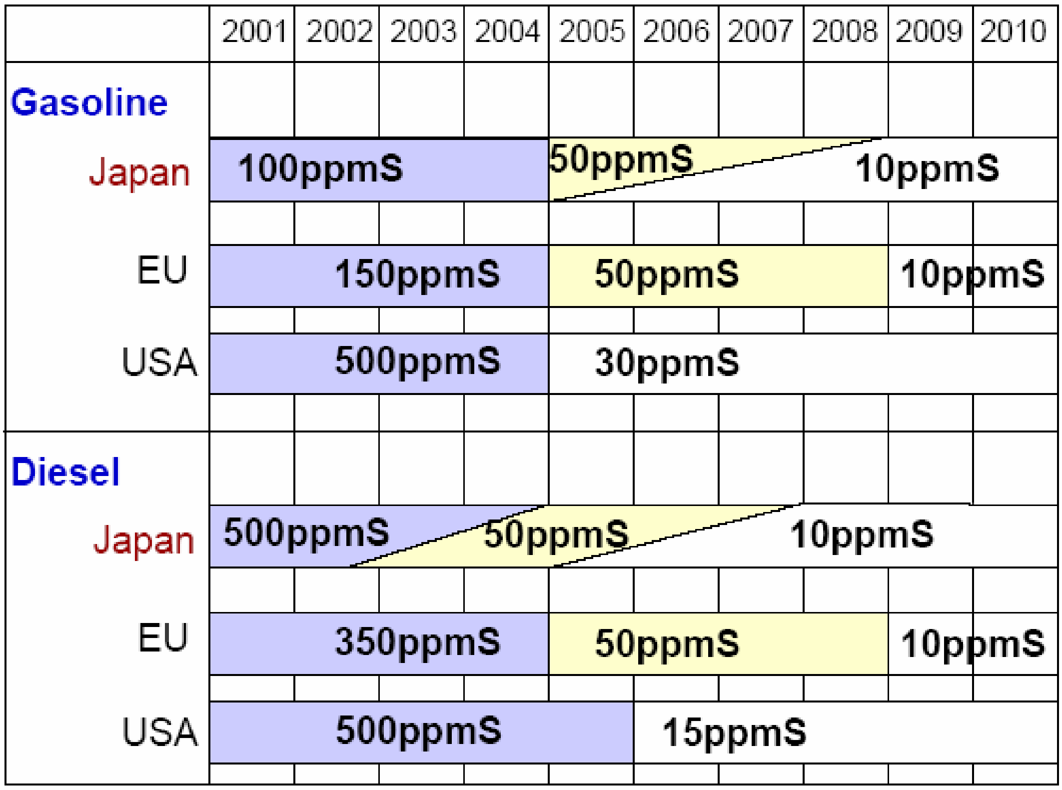
large-scale hydroelectric projects, which has resulted in virtually no growth in global hydroelectricity generation since the mid-1990s. China's controversial Three Gorges project will inject new capacity, but such projects remain unpopular internationally.

2.1.6 A shift in demand to lighter, cleaner products

Governments around the world are continuing to tighten product specification requirements, in particular those relating to the sulphur content of fuels. At the same time, the average sulphur content of the crude oil produced globally is slowly increasing. The joint impact of more sour (high sulphur) crude oil and greater restrictions on the quantities of sulphur permissible in refined products has had, and is continuing to have, a profound impact on the refining industry worldwide.

More and more countries around the world are requiring dramatic reductions of sulphur levels in transportation fuels, as well as reductions in other pollutants such as particulates and NO_x.

Figure 6: Regulations on sulphur content in automotive fuels



Source: Japan Clean Air Program

The Bank's countries of operation have considerable spare refining capacity, a commodity that is in increasingly short supply globally, but to be able to utilise this capacity the refineries need to be able to produce products that meet the quality requirements of product-importing regions, particularly the EU and North America.

The upgrading of some refineries has already begun, especially those in Eastern Europe and in western Russia, but there is still a long way to go before product output generally meets standards being adopted in the EU and North America. Such projects not only allow refineries to compete for international markets, boosting competition, but also have the beneficial side-effect of improving the quality of products available on the local market, helping to ease local pollution levels.

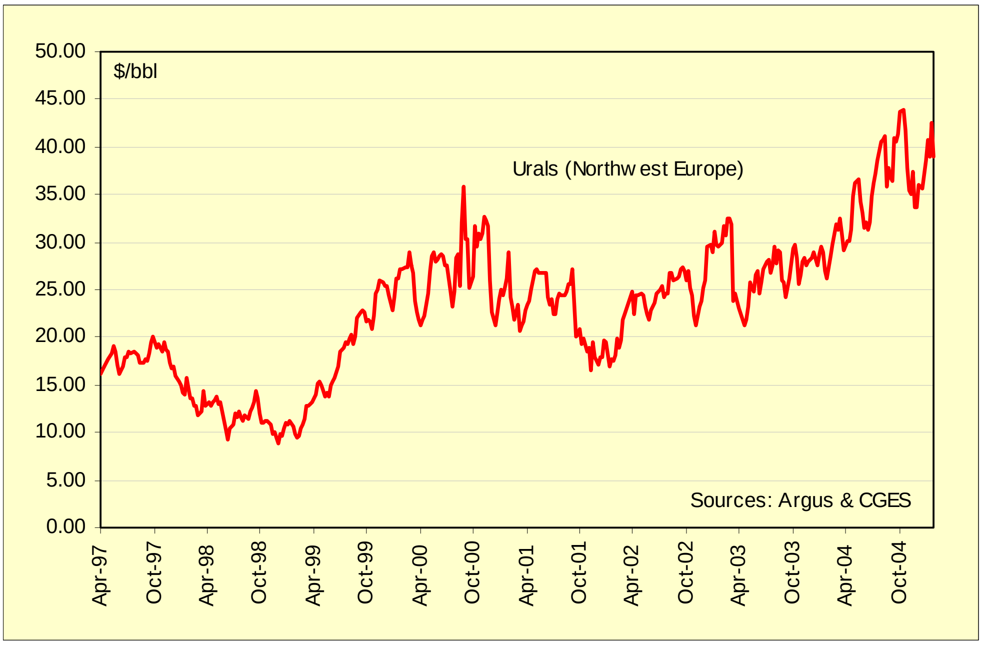
2.2 THE IMPACT OF HIGHER OIL PRICES ON THE BANK'S COUNTRIES OF OPERATION

The global changes in the oil and gas business have had a profound impact on the requirements of the Bank's countries of operation in the oil and gas sectors. In addition to these global changes, the oil and gas industries of the Bank's countries of operation (particularly in the upstream and, to a lesser extent, in the midstream sectors) have themselves undergone major transformations since 1999, partly as a result of the global changes themselves, but also as a result of purely domestic factors.

Oil and gas have been, and will continue to be, major drivers of economic development in those of the Bank's countries of operation that hold significant reserves of these fuels. Such is their economic importance to these countries that it is inconceivable that their extraction will not continue and it is therefore not a question of *whether* these resources are developed, but *how* they are developed. The Bank perhaps has an important role to play, or rather continue to play, in promoting best environmental practice in oil and gas extraction and transportation projects in its countries of operation.

In the low oil price environment prevailing when the Bank last revised its Natural Resources Policy, oil producers everywhere faced a very uncertain future and this was particularly true in the republics of the former Soviet Union (FSU). In Russia, oil production had fallen by nearly 50% from a Soviet-era peak of more than 11 mbpd in the late 1980s to just over 6 mbpd in 1996. By 1999, Russia's oil production had risen by just 100,000 bpd (less than 2%) and it was generally believed that Russia would struggle to maintain production even at this much reduced level without substantial foreign investment in the country's upstream oil sector.

Figure 7: The price of crude oil (1995-2004)



At a price of $10/bbl for Dated Brent crude oil (or less than $9/bbl for Russia's Urals export blend) it was highly questionable whether new oil production in Russia and other FSU republics could ever be profitable given the huge distances over which that oil needed to be transported to reach markets in Central and Eastern Europe and export terminals on the Baltic Sea or the Black Sea. However, it was also recognised that raw materials production and export (including oil and gas) were vital to the future growth of the economies of several of the Bank's countries of operation, in particular the Russian Federation, Azerbaijan, Kazakhstan and Turkmenistan.

In the five years or so since the drafting of the Bank's last Natural Resources Policy oil prices have surged, with Dated Brent averaging more than $38/bbl in 2004 and Russia's Urals averaging between $32/bbl and $35/bbl, depending on destination. The value of crude oil grades exported from Caspian Sea Region countries has also soared during this period.

Table 1: Annual average crude oil prices ($/bbl)

	Dated Brent	Urals NW Europe	Urals Med.	Siberian Light Med.	Tengiz	Azeri Light	Urals Friendship Czech	Urals Friendship Germany
1998	12.86	12.16	11.97	12.71	13.34	0.00	10.44	10.17
1999	17.99	17.48	17.31	17.99	18.32	21.56	15.61	15.37
2000	28.48	27.10	26.65	27.97	28.98	29.30	25.57	24.98
2001	24.35	22.99	22.85	24.07	24.97	25.34	21.31	20.97
2002	24.76	23.56	23.45	24.29	24.57	25.17	22.32	21.91
2003	28.94	27.43	27.39	28.61	28.77	30.04	25.54	25.15
2004	38.41	34.56	34.78	37.20	37.75	39.45	32.02	32.02

Source: Argus Global Markets & CGES

With international oil prices at $40/bbl and futures markets yielding a price of at least $30/bbl to the end of the current decade, the picture is now very different from the one prevailing at the time the last Natural Resources Policy was drafted at the end of the 1990s. Almost any new oil project in Russia or the Caspian Sea region now looks profitable and the challenge has shifted from one of how to produce and export oil profitably to one of how to get all the oil produced to export outlets. This creates a very different environment in which the Bank will be asked to operate as we look forward.

The other important change that high oil prices have wrought on the potential involvement of the Bank in the oil and gas sectors of the hydrocarbons producing countries is that the indigenous oil and gas companies have become almost immeasurably more cash-rich than they were in the late 1990s. At that time, it was generally believed that the only way that the decline in Russian oil production could be first halted and then reversed was through a massive injection of foreign capital and foreign oilfield expertise. The first five years of the 21st century has proven this assumption to have been almost entirely incorrect.

The devaluation of the Ruble in 1998 dramatically reduced local costs for Russian oil producers, while rising international oil prices provided a tremendous boost to their revenues. Rather than seeking investment from foreign oil companies, the recently-privatised Russian oil industry (or parts of it, at least) sought to 'buy-in' expertise and technology by selectively recruiting Westerners to senior operating positions and signing contracts with major Western oilfield service companies, who in any case provide much of the technology used by Western oil companies.

The first-tier Russian oil companies (Lukoil, TNK-BP, Sibneft, Surgutneftegaz, Rosneft, Slavneft and Yukos prior to its dismemberment at the hands of Russia's tax authorities) have found little difficulty raising finance on international markets as they have gradually opened up their management and accounting practices to greater scrutiny (at least on the face of it) and become more like their Western counterparts.

Just as oil prices have risen dramatically since the Bank last updated its Natural Resources Policy, so there is no guarantee that they will not fall again in the years ahead. It is perhaps pertinent, then, to address the issue of a break-even price for Russian oil production. There are, of course, as many different break-even prices for Russian oil as there are oilfields in Russia, but some clear groupings can be made. New greenfield development projects will have a significantly higher break-even price than existing fields in a similar location. When oil prices fall, the first activity to be cut back is exploration and the development of new deposits, the last is current production, which remains untouched as long as it is covering the variable costs of operation.

A number of different assessments of the break-even price of Russian oil production have been made in recent years as people have attempted to assess the likely growth in Russian oil production. Wood MacKenzie has estimated average break-even oil prices for Russian oil production of US$10.50-11.00/bbl (discounted to Jan 1 2004) in developing their Russian oil production scenarios.[2] This figure echoes the $11/bbl break-even price for Russian oil published in Forbes Magazine in December 2001.[3] The CGES presented a similar figure for the fully-built-up cost of Russian oil production (including transport) at its seminar on Russian oil in London in March 2004.[4] New developments in Russia, particularly those in Eastern Siberia where basic infrastructure for access to remote sites is extremely limited, will have a higher fully-built-up cost; even so, it is probably not more than $15/bbl.

In its Russian Oil & Gas Yearbook[5], published in July 2003, Renaissance Capital compared drilling costs in Russia with those in the US. The analysis yielded average drilling costs of $188/km in Russia, compared with costs of $685/km in the US onshore, the data being for 2002 in Russia and 2001 in the US. The low cost of drilling in Russia would tend to support the relatively low break-even price for oil projects in the country. Further support can be found in the lifting costs reported by Russian oil companies in their annual reports. Although not all of the major Russian oil companies report lifting costs, those that do all show similar trends. The devaluation of the Russian Rouble in 1998 led to a steep drop in US$-denominated lifting costs, typically reducing them from between $4/bbl and $8/bbl to a range between $1.50/bbl and $2.60/bbl. Since the year 2000, lifting costs among the Russian oil majors have remained stable within this new, lower range. Although some increase is expected in the 2004 figures, it is not expected to be large. Renaissance Capital suggested in its 2003 report that 'more expensive technology will be needed in Russian fields as the share of hard-to-recover reserves grows, but we think that recovery rates could increase enough to offset this in per barrel terms.'

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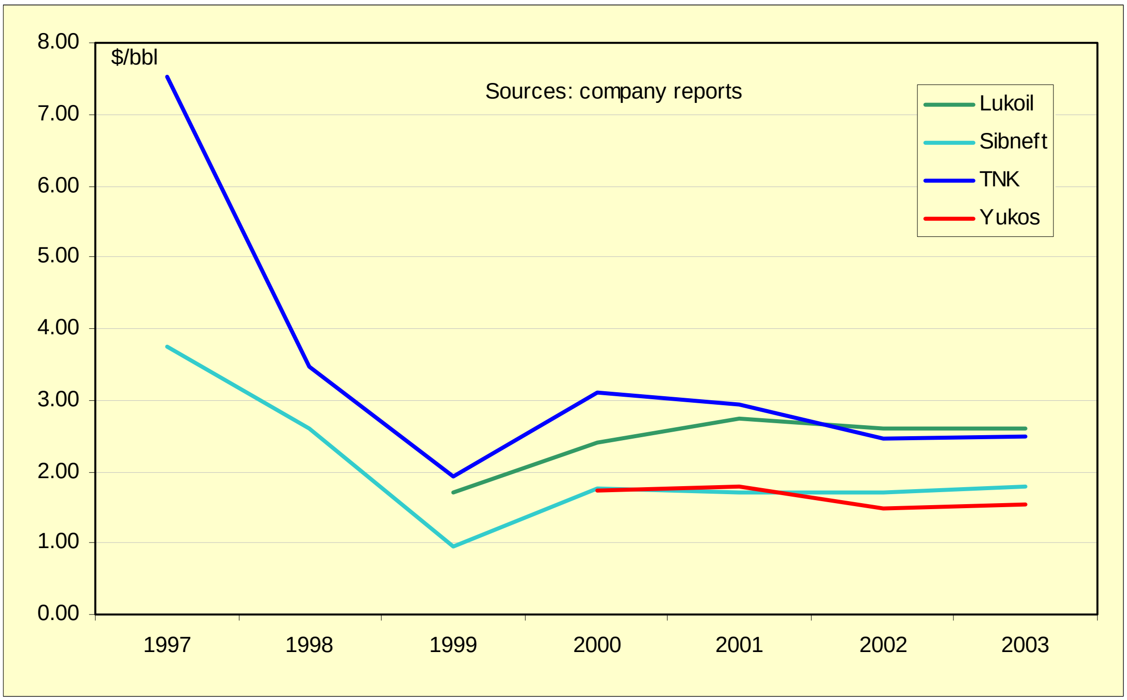
[2] http://www.rigzone.com/news/insight/insight.asp?i_id=59
[3] 'Russian Oil Roulette', Forbes Magazine 26/12/01. http://www.forbes.com/2001/12/26/1226russianoil.html
[4] Chalabi (2004)
[5] Renaissance Capital (2003)

Figure 8: Lifting costs in Russia



2.3 THE CHANGING STRUCTURE OF THE RUSSIAN OIL AND GAS INDUSTRY

2.3.1 The Russian oil industry

The Russian oil industry had already been largely privatised by 1999 through a number of highly questionable auctions and 'loans for shares' deals between the Russian government and privately-owned Russian banks. Since 1999, the Russian government has sold off most of its shares in the country's integrated oil companies (most recently selling through auction its final 7.59% stake in Lukoil to ConocoPhillips). At the same time, the government appears to have been following the somewhat contradictory path of re-nationalising parts of the upstream industry, forcing the sale of Yukos' major upstream subsidiary (Yuganskneftegaz) to pay off part of the company's alleged past tax debts.

Russia's only state-owned oil company, Rosneft, has been transformed from something of an 'orphanage' for unwanted Russian oil assets in the 1990s, into a strong and dynamic company. This has largely been achieved through acquisition of a number of independent oil companies operating in the Timan-Pechora basin of north-western Russia and as a result of the company's role in several potentially large projects off the coast of Sakhalin Island. More recently, Rosneft emerged as the ultimate purchaser of Yuganskneftegaz, which was forcibly sold at auction to pay off alleged tax debts incurred by its parent company, Yukos. The inclusion of Yuganskneftegaz as part of Rosneft has boosted Russia's state oil company's production from around 450,000 bpd in 2004 to 1,440,000 bpd in January 2005, putting it on a par with Russia's largest oil companies, Lukoil and TNK-BP.

Russia's upstream oil industry has become dominated by a small number of extremely large oil companies. In 2004, just four companies (Yukos, Lukoil, TNK-BP and

Surgutneftegaz), each producing in excess of 1 mbpd, accounted for 65% of Russia's total oil output, while a further five companies (Sibneft, Tatneft, Rosneft, Slavneft and Bashneft) took this share to 90% of the total. In contrast, what might be regarded as Russia's independent oil sector plays only a very minor role. More than 150 small private oil companies and joint ventures accounted for just 5% of the country's total oil production, while the two Production Sharing Agreements with foreign companies that had begun extracting oil (the Shell-led Sakhalin 2 project and Total's Kharyaga project) contributed just 0.5% of Russia's output in 2004, producing at a combined annual average rate of just 50,000 bpd.

Russia's 'independent' oil sector includes joint ventures between Russian and foreign oil companies as well as purely domestic enterprises. Indeed, the largest player in this sector is Vanyoganneft, a 50/50 joint venture between TNK-BP and Occidental, which produces around 50,000 bpd.

Many of Russia's more private oil companies hold a small number of licences for fields in a very specific geographical area. In the past, such companies have tended to become targets for acquisition by one or another of Russia's vertically-integrated oil companies. For example, Lukoil gained control of several independent oil companies operating in Timan-Pechora during the 1990s as part of the consolidation of its activities there. AmKomi, KomiArcticOil and KomiQuest were all subsumed into Lukoil in January 2002. More recently, Russneft, established in September 2002 and headed by former Slavneft head Mikhail Gutseriev, had grown through acquisition into a 140,000-bpd producer within two years.

Table 2: Russia's oil production by company (mbpd)

	2000	2001	2002	2003	2004	2004 % share	2004 cumulative % share
Yukos	0.995	1.166	1.401	1.619	1.720	19%	19%
Lukoil	1.160	1.256	1.515	1.583	1.688	18%	37%
TNK-BP	0.699	0.998	1.079	1.237	1.411	15%	52%
Surgutneftegaz	0.816	0.884	0.988	1.085	1.197	13%	65%
Sibneft	0.345	0.414	0.529	0.630	0.682	7%	73%
Tatneft	0.489	0.494	0.494	0.495	0.504	5%	78%
Rosneft	0.270	0.300	0.324	0.366	0.433	5%	83%
Slavneft	0.244	0.299	0.326	0.363	0.441	5%	88%
Bashneft	0.240	0.238	0.241	0.242	0.242	3%	90%
Gazprom	0.201	0.204	0.212	0.221	0.243	3%	93%
Russneft				0.040	0.129	1%	94%
Rostopprom	0.010	0.013	0.013			0%	94%
JVs and juniors	0.900	0.643	0.432	0.536	0.473	5%	99%
PSAs	0.044	0.052	0.039	0.042	0.048	1%	100%
Total Russia	**6.413**	**6.960**	**7.594**	**8.460**	**9.215**		

Source: CGES from various sources. Figures calculated from output reported in metric tonnes.

Foreign investors had hoped to persuade the Russian government to adopt the Production Sharing Agreement (PSA) as the contract form of choice for large-scale upstream investment in oil and gas projects. However, attitudes in Russia have hardened against PSAs, except perhaps for particularly large, complex and expensive projects in 'difficult' areas. Russian oil companies, which saw PSAs as conferring benefits on foreign investors for which they themselves were not eligible, began to lobby against PSAs, but perhaps the most important spur to opposition was the remarkably favourable terms that the Sakhalin Energy Investment Company (SEIC) secured for itself when negotiating the agreement for its Sakhalin II project. Ian Rutledge has noted that, 'the particular terms of the Sakhalin II PSA are not typical of those incorporated in most PSAs throughout the world. The Sakhalin II PSA is particularly disadvantageous to the Russian Party, and it is surprising that the Russian Party agreed to these terms.'[6] In the light of the terms of the Sakhalin II PSA it is perhaps not surprising that Russia has turned its back on production sharing agreements as a preferred form of contract for upstream oil and gas projects.

There are some indications that PSAs might make a comeback as the preferred contractual model for large-scale, offshore oil and gas projects. Natural Resources Minister Yuri Trutnev has long been a proponent of PSAs for such projects and has recently proposed the creation of a state-controlled company to oversee such contracts.[7] While the reintroduction of PSAs is seen as a positive move, the creation of a new state-controlled company to oversee them has not been welcomed either by potential private-sector investors, or by the Economic Development Minister German Gref. There is a fear that such a company would be open to abuse for political reasons, reducing transparency and competitiveness and thereby hampering investment.

There is huge uncertainty over the future shape of the Russian oil industry in the wake of the dismemberment of Yukos and the effective re-nationalisation of its major upstream subsidiary. There are fears that the campaign against Yukos marks the start of a more general re-nationalisation of the oil industry, with all the major Russian oil companies at risk. Others suggest that the action against Yukos was a one-off case, triggered by the political ambitions of the company's CEO Mikhail Khodorkovsky. A third group of commentators see the Yukos affair as an attempt by influential individuals within the new Kremlin hierarchy to get control of some of Russia's major economic assets, just as Khodorkovsky and the other oligarchs did under President Yeltsin almost a decade ago. More recently, an announcement that foreign companies would not be allowed to bid for licences to explore and develop several major mineral deposits (including, but not limited to, oil and gas) in 2005 was taken as an indication that foreign investors were no longer welcome in the Russian oil and gas sector.

In August 2004, the author likened the Russian government's campaign against Yukos to the Roman Republic's campaign against Carthage, dubbing it 'Putin's Punic War'. In an article published at the time, the author wrote, 'It is as if by daring to challenge President Putin Mikhail Khodorkovsky has brought about the destruction of the company he created. Not content merely with bringing down an oligarch who strayed too far from business into politics, the Kremlin now appears intent on expunging every trace of the oil company he created, much as the Roman Republic sought to eradicate every trace of the North African city-state that sought to challenge its supremacy in the Mediterranean more than 2,000 years ago.'[8] The author believes that the campaign that has been waged against Yukos is just that, an attack on a single Russian oil company and its chief executive. The affair does

[6] Rutledge (2004) p5.
[7] 'Investors question Trutnev initiative', Argus FSU Energy, 20 May 2005, p4.
[8] Lee (2004-2), p5.

serve other useful purposes for the government, though. It sends a very clear warning to the other major Russian oil companies and to the oligarchs that own them. It reinforces the 'stay out of politics' message that Putin sent to the oligarchs soon after he came to power in Russia and it also says, 'pay the taxes you owe to the Russian government.' The creation of a second state-owned oil company in Yuganskneftegaz, if the rest of Rosneft completes its planned merger with Gazprom, does not appear to have been the driving force behind the campaign against Yukos.

The whole Yukos affair raises serious concerns about the rule of law in Russia, the transparency of the legal process and the influence of key, often unaccountable, individuals over the creation and implementation of policy. Outside Russia some of the oligarchs who gained control of the country's oil industry (particularly Mikail Khodorkovsky) had come to be seen by some as champions of reform and Western business practice, [9] modernising the Russian oil industry and opening it up to outside scrutiny. Within Russia the oligarchs continued to be seen as little more than thieves who had plundered the country's most valuable assets and made themselves fabulously rich at the expense of the Russian citizenry, giving little if anything back to the communities in which they operated.

The author believes that the private oil sector will continue to operate alongside the state-owned oil sector. Oil companies are likely to come under closer scrutiny from government, but at the same time they will operate in an environment of greater certainty as the laws governing activity in the country's hydrocarbons industries are revised, reducing the areas that are left open to individual interpretation. . This process will not happen overnight, though. The creation of a clear set of rules regulating hydrocarbons activity, with a stronger role played by the Federal authorities in Moscow, will be an ongoing process.

2.3.2 The gas industry

Russia's gas industry has changed far less than the country's oil industry over the past five years. According to a recent OECD Economics Department Working Paper[10], 'the gas industry is perhaps Russia's least reformed major sector. Prices are regulated, exports are monopolised and the domestic market is dominated by a state-controlled, vertically integrated monopolist, OAO Gazprom.' Gazprom not only accounts for the lion's share of the country's natural gas production, but also owns and operates the gas pipeline network and is responsible for gas distribution and sales across most of the country as well as exports to the hard-currency markets of Europe. This hold on the downstream (distribution) end of the business is likely to increase, since Rosneft is seeking to transfer to Gazprom its distribution business in Russia's Far East.

Russia's major oil companies are also producers of gas, with associated gas produced alongside oil at many Russian oilfields. Some of this gas is used on site to generate power for oilfield operations or is re-injected into the oil reservoirs to maintain pressure. There are also a small number of independent Russian gas producers, most notably Itera and Novatek.

[9] In 2002, Mikhail Khodorkovsky was named 'Entrepreneur of the Year' by Vedemosti, Russia's pre-eminent business newspaper, published jointly by the Financial Times of London and the Wall Street Journal of New York. Yukos was also named by the

[10] Ahrend R, & Tompson W., 'Russia's Gas Sector: the Endless Wait for Reform?', OECD Economics Department Working Paper No. 402, 17th September 2004

The Russian state holds 38.37% of Gazprom directly and indirectly controls approximately a further 16% held by Gazprom subsidiaries. Foreign investors are prevented from directly owning domestic shares in Gazprom, but the government is seeking to secure for itself a direct majority stake in the company prior to lifting this 'ring fence' and permitting open trade of shares in the company. The government had intended to create this majority shareholding by merging Gazprom and Rosneft to create a single national oil and gas company, but Rosneft's purchase of Yuganskneftegaz, together with the oil company's opposition to the merger, has complicated this process.

Table 3: Gazprom share ownership structure

	%
Russian state	38.37
Russian firms (including Gazprom subsidiaries)	36.10
Russian individuals	14.03
Foreigners	11.50
(incl. Ruhrgas)	6.50

According to a recent study on Russia's strategic commodities by the Swedish Defence Research Agency[11], Gazprom is in poor shape after years of mismanagement, lack of investment, poor field and infrastructure maintenance, increasing debt and lack of transparency.

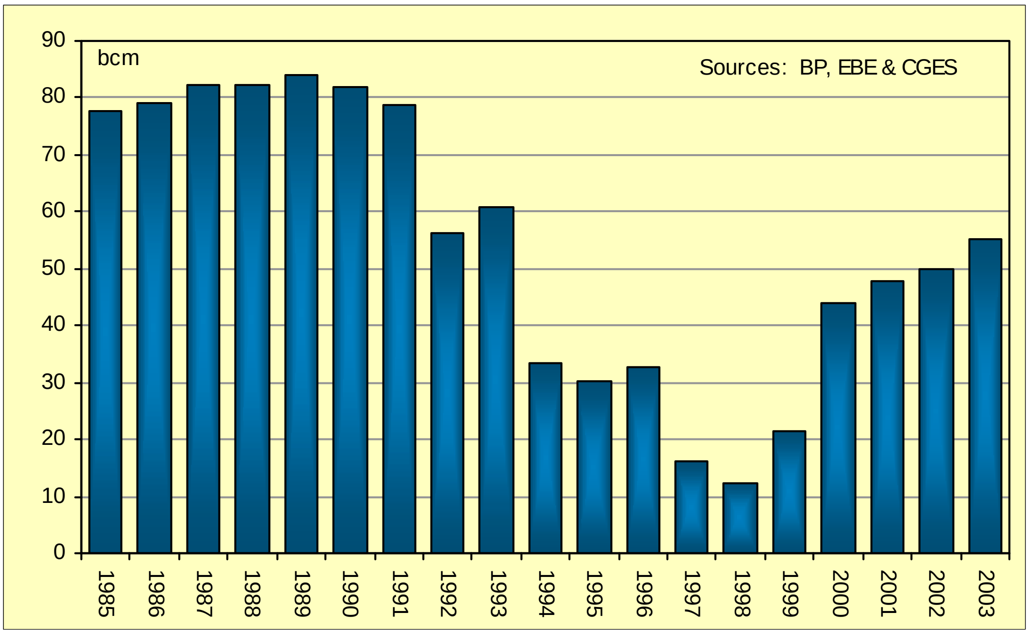
In order to meet its supply commitments to customers in Europe and continue to supply the domestic market, Gazprom has turned to the Central Asian republics of the FSU as a source of cheap gas. With little in the way of alternative markets for their gas, Gazprom has found it possible to secure a series of very attractive deals to buy gas cheaply from Turkmenistan, Uzbekistan and Kazakhstan, which it can then on-sell to its own customers in Western Europe. The hard-currency gas markets of Europe have been jealously guarded by Gazprom, with the company refusing to grant space in its pipeline network for third party gas sales to countries beyond the borders of the FSU. The lack of any gas export infrastructure linking the Central Asian republics to non-FSU customers (except for a small pipeline linking Turkmenistan and Iran) has left Central Asian gas producers entirely dependent upon the goodwill of Gazprom to export their gas. When Turkmenistan attempted to put pressure on Gazprom to raise the price it paid for gas in the mid-1990s it soon found that its exports dried up completely and Turkmenistan's gas production plummeted as a result, falling to just 12.4 billion cubic metres (bcm) in 1998.[12] It was only after gas deliveries to Gazprom were restored that production began to recover. However, Turkmenistan again cut off supplies to Gazprom at the beginning of 2005 in an attempt to force the Russian company to improve the price paid for Turkmenistan's gas.

[11] Leijonhielm J. & Larsson R. L., 'Russia's Strategic Commodities: Energy and Metals as Security Levers', Swedish Defence Research Agency, Stockholm, November 2004.

[12] Lee, J., 'Prospects for Caspian Gas', CGES, London, 2001.

Turkmenistan initially sought a price of \$60/’000 m^3 for its gas exports and eventually agreed on a rate of \$58/’000 m^3 with Ukraine. Gazprom, however, held out for a price of \$44/’000 m^3, which had been agreed in the original three-year contract covering the period 2004-2006. Gazprom eventually prevailed, but agreed that the full price would be paid in cash, rather than 50% cash, 50% barter goods as had been the case previously.

Figure 9: Turkmenistan's gas production



Gazprom’s monopoly control of Russia’s gas pipeline network and its own position as a major gas producer and exporter have created serious problems of pipeline access for the country’s other gas producers. Gazprom has effectively used restrictions on access to Russia’s pipeline network to limit gas production by its competitors and to prevent those who it does permit to produce gas from selling into the lucrative West European market.

The Russian Ministry of Energy has suggested that Gazprom should be broken up into separate upstream, transportation and distribution companies, but little real progress on this issue appears to have been made. Gazprom’s strong personal links to President Putin have helped the company to lobby for minimal changes to the environment in which it operates and there remains no discernable move to separate the gas transportation network into a separate company. In an interview given to the Financial Times in April 2004 and carried on the Gazprom website[13], the company’s chairman Alexei Miller said that, “if independent producers were willing to participate in the reconstruction, upgrading and building of the new transportation system, they would be welcome. We should move away from the practice when independent gas producers think their only responsibility is to explore and produce gas. These are significant volumes of gas, and we should resolve problems of transportation jointly. Why should we simply free up capacity for their gas in our pipeline?”

13 http://www.gazprom.com/eng/articles/article11448.shtml

Attempts to create a second-tier gas industry have had little success to date. For a time it looked as though Itera might emerge as a significant gas producer and exporter, but its role has diminished to one of supplying gas to customers in former Soviet republics. Novatek is emerging as a significant player in Russia's gas industry; but, without access to export pipelines for its output it will remain at the mercy of Gazprom. Unless second-tier gas producers in Russia (including the oil companies who are producing associated gas) can gain unimpeded access to Gazprom's pipeline system on a commercial basis the creation of a competitive gas industry in Russia seems doomed to failure. External support for second-tier gas companies, whether from institutions such as the EBRD, or from foreign oil companies such as Total, is unlikely to break Gazprom's monopoly, or to lead to the restructuring of the Russian gas industry by separating the production and transportation functions. Despite repeated pledges from the Russian government that reform of Gazprom would begin, almost nothing has been accomplished. The most effective pressure for the reform of the Russian gas sector could come through Russia's WTO accession process. The European Commission's requirements to be met by Russia before it would support its membership of the WTO included the opening of the Russian gas pipeline network to independent gas producers. However, the EU appeared to have dropped this requirement during the negotiations over the EU's support for Russia's accession to the WTO in May 2004. In the final agreement between Russia and the EU, Russia committed itself to raising domestic gas prices (see below), but there was no mention of open-access to gas pipelines.[14] Any future hope of putting pressure on the Russian government to open access to gas pipelines through the country's WTO accession process now lies with other WTO members, such as China and the US, seeking bilateral agreements with Russia. However, as with the EU, it is quite likely that this issue, if raised at all, would be used as a sacrificial pawn in bargaining for other concessions from Russia.

It may be worth exploring whether any leverage on the open access issue can be gained from Russia's adoption of the Kyoto Protocol on climate change. Open access to gas pipelines for companies other than Gazprom would lead to a reduction in the flaring of associated gas by oil producers, who would have a viable alternative means of disposing of their gas. Whether such logic would have any impact, though, is far from certain.

Some attempt has been made to raise gas prices on the domestic Russian market, but it is generally accepted that these steps have not gone far enough. Domestic gas prices in Russia remain well below those charged for exports to hard-currency markets beyond the borders of the Commonwealth of Independent States (CIS) in Europe.

Russia's Energy Strategy for the Period to 2020[15] suggests that 'maintenance of necessary growth in investment demands that gas prices increase to \$40-41/'000 m^3 by 2006 and to \$59-64/'000 m^3 by 2010 (excluding VAT, payments for transportation of gas through gas distribution networks and provision of supply services). During negotiations between Russia and the EU over the accession of the former to the World Trade Organisation (WTO), it was agreed that "gas prices for domestic industrial users will gradually rise from

[14] 'Russia-WTO: EU-Russia deal brings Russia a step closer to WTO membership' http://europa.eu.int/comm/external_relations/russia/intro/ip04_673.htm

[15] 'Energy Strategy of Russia for the Period to 2020' (in Russian), August 2003. Can be downloaded from http://www.mte.gov.ru/docs/32/189.html

the current $27-28 to $37-42 by 2006 and $49-57 per TCM by 2010."[16] Although these figures are somewhat lower than those deemed necessary in Russia's Energy Strategy document, they are more significant for having been enshrined in a binding international agreement.

Table 4: Average natural gas tariffs and tariff increases

	1997	1998	1999	2000	2001	2002	2003
Natural gas tariffs ($/'000 m^3)							
Households	19.2	15.6	7.9	8.0	9.3	11.6	15.9
Industrial users	46.0	26.5	10.6	12.2	14.9	17.6	23.8
Export to non-CIS Europe	84.2	80.5	60.0	103.5	119.1	107.3	128.1
Natural gas tariff increases (% change from December to December, based on Ruble prices)							
Households		36.9	27.6	16.5	19.9	33.6	34.8
Industrial users		-3.4	1.2	31.9	26.8	27.1	31.8

Source: OECD Economics Department Working Paper 402. Using data from the Federal Energy Commission, Goskomstat RF and United Financial Group.

Non-payment and barter payment for gas delivered, which used to be a huge problem for Gazprom, seems to have been largely overcome. At a press conference in March 2004, Alexander Ryazonov, Deputy Chairman of Gazprom's Management Committee, reported that the company had received RR250 bn as payments for 98.4% of the gas supplied to the domestic market. In the Audit Report of Gazprom's Statutory Consolidated Financial Reports for 2003, the company shows Accounts Receivable (with payment expected within twelve months of the reporting date) from buyers and customers at the 31st of December 2003 of RR130.4 bn, representing 22% of the company's total current assets.

2.4 Changes in the Oil and Gas Sectors of the Caspian Sea Region Countries

While there have been fewer changes in the structure of the oil and gas industries of the Caspian Sea Region countries than in Russia, the business environments in the hydrocarbons sectors of Azerbaijan, Kazakhstan and Turkmenistan have all changed since the late 1990s, offering new opportunities and presenting new challenges to companies wishing to invest and to banks seeking to support those investments.

2.4.1 Azerbaijan

The biggest change that has occurred in Azerbaijan has been the result of geology, not politics. The political and regulatory environment in which the oil and gas industry operates in Azerbaijan is probably the least changed of all the major hydrocarbons producers in the Bank's countries of operation. However, the failure of any of the consortia of companies who signed Production Sharing Agreements (PSAs) during the 1990s to find new oil or gas reserves off the coast of Azerbaijan has changed the operating

[16] Kernohan, D. and Vinokurov, E., 'The EU-Russia WTO Deal: Balancing Mid-term and Longer-term Growth Prospects?', Centre for European Policy Studies, January 2005. The full article may be found on the CEPS website at http://www.ceps.be/Article.php?article_id=382

environment in that country for upstream oil and gas projects. The two BP-led consortia developing the Azeri, Chirag and deepwater part of the Guneshli oilfields (ACG) and the Shah Deniz gasfield were both targeting fields that had already been discovered and had some appraisal work carried out on them. The other PSAs were for wildcat drilling on structures that had been identified through seismic surveying and other non-invasive techniques, although the structures identified were generally (and misleadingly) referred to as ‘fields’.

The failure to make significant discoveries has led many of the consortia to abandon their projects (often paying penalties rather than completing agreed drilling programmes) and has dampened enthusiasm among the major Western oil companies for future exploration off the coast of Azerbaijan. The next phase of oil development offshore Azerbaijan may well include a reappraisal of offshore data and an attempt to attract Asian companies and smaller Western independents to explore for oil and gas. The completion of the Baku-Tbilisi-Ceyhan (BTC) pipeline may bring a new lease of life to Azerbaijan’s upstream oil industry if there is spare capacity available for other producers at reasonable prices.

Onshore, Azerbaijan has attracted a mixture of small Western independent oil companies and, more recently, Asian companies. Onshore projects have generally involved the rehabilitation of old oilfields and have included a sizeable proportion of environmental remediation, bringing immediate benefits to the local area. However, Azerbaijan’s discovered onshore oilfields have been exploited since the late 19th century and incremental production is likely to be modest and projects relatively small.

Azerbaijan’s oil production is expected to increase to some 1.0-1.2 mbpd towards the end of the decade. The infrastructure to export this oil is either in place (the Baku-Novorossiysk and Baku-Supsa pipelines), or is under construction (the Baku-Tbilisi-Ceyhan pipeline). No major new oil export pipeline projects from Azerbaijan are likely unless there are major new oil discoveries in the country. Even if more oil were to be found, the long lead-times involved in bringing Caspian Sea oilfields into production may well mean that significant new production only comes on stream after production rates from the ACG fields has begun to decline, possibly freeing up capacity in the BTC pipeline. The BTC pipeline could be expanded to carry up to 1.8 mbpd (from its original design capacity of 1.0 mbpd) if the demand materialises from other oil producers, perhaps in Kazakhstan.

2.4.2 Kazakhstan

Kazakhstan continues to welcome foreign oil companies to explore for and develop oil and gas on its territory, but high oil prices and a growing sense of its own importance as a potential alternative to Middle Eastern oil suppliers have led the government to seek more attractive terms from both new and existing investors.

New oil projects in the country are required to have a majority state ownership through KazMunaiGaz – the state-owned oil and gas company. Existing projects have found themselves coming under increasing pressure from the government. At the end of 2002, TengizChevroil found itself in dispute with the Kazakhstani government over the funding of the next stage of the Tengiz project, designed to lift production from 250,000 bpd to 440,000 bpd. The project partners wanted to fund the expansion from export revenues, while the government wanted the companies to raise the funding through loans, while paying taxes on their export revenues. The government eventually prevailed.

More recently, the Kazakhstani government decided that it had the right to pre-empt the sale of BG's stake in the super-giant Kashagan project. Initially, BG had intended to sell its stake to Chinese buyers, but most of the other members of the consortium decided to exercise their own pre-emption right (as laid down in the original contract). The Kazakhstani government then decided that, although it was not a member of the Kashagan consortium, it had an over-riding pre-emption right as the host government, which superseded the rights of the consortium members. The government subsequently enacted legislation enshrining this right. However, at the time of writing, the issue of the sale of BG's stake in Kashagan has still not been resolved, although it seems likely that the KazMunaiGaz will end up buying at least half of BG's stake.

Kazakhstan's oil production is expected to continue to grow rapidly to the end of the decade and beyond. Production from the Tengiz oilfield should rise to nearly 500,000 bpd by 2007 and further expansion could raise output to 750,000 bpd by the end of the decade. Offshore, the Kashagan field is due to commence production in 2008. Initial production is expected to be 75,000 bpd, rising gradually to 450,000 bpd and reaching 1.2 mbpd at full capacity, which is planned for 2015.

Kazakhstan expects to triple its current level of oil output to some 3 mbpd by 2015. Most of the additional oil produced over the next ten years is likely to be exported from Kazakhstan, requiring significant investment in additional export infrastructure. The country's current export capacity is formed of the CPC pipeline (which at present can carry 510,000 bpd of crude from Kazakhstan), the Atyrau-Samara pipeline (with a capacity of around 300,000-350,000 bpd). In addition, approximately 150,000 bpd is shipped across the Caspian Sea to Makatchkala and Baku for onward delivery to export terminals at Novorossiysk and Batumi respectively. A further 85,000 bpd is exported by rail, mostly to China and to the port of Tallinn in Estonia. As a result, Kazakhstan's total export capacity currently stands at a little over 1 mbpd. A new export pipeline is being built from eastern Kazakhstan to China, but this is expected to have an initial capacity of just 200,000 bpd, although this could be doubled in the future.

Once the Tengiz and Kashagan projects are operating at full capacity, Kazakhstan will require an additional 1.0-1.5 mbpd of export capacity, or thereabouts. Some of this could come through expansion of the CPC pipeline to 1.37 mbpd (adding perhaps another 500,000 bpd of capacity to carry crude from Kazakhstan) and some could come through use of an expanded BTC pipeline, with oil being delivered from Kazakhstan to Baku by ship, since the construction of international subsea pipelines in the North Caspian is likely to run in to opposition from Russia.

There has been a suggestion that Kazakhstan should build an export pipeline running southwards through Turkmenistan and into (or even through) Iran to facilitate exports of Central Asian oil through the Persian Gulf. Any such high-profile project would not only incur a similar level of external scrutiny as the BTC project but would also, because of the involvement of Iran, run into opposition from the US Administration.

2.4.3 Turkmenistan

Turkmenistan has lagged behind the other Caspian littoral states of the FSU in realising the potential of its hydrocarbon resources. Although the country continues to be a significant gas producer, it remains tied to the Russian market. In the oil sector, it has not been successful in attracting interest from foreign oil companies on the same scale as Azerbaijan or Kazakhstan. According to a report carried in Upstream, 'The dictatorship of President Saparmurat Niyazov, lack of economic and political reform, and behind-the-scenes political games have constrained exploration and development of the oil-rich Turkmen shelf.'[17]

Turkmenistan continues to hold relatively little interest for Western oil and gas companies. In the past both Shell and Mobil have had exploration rights to large areas of the country, but these have been allowed to lapse with little or no work being carried out. There are currently five upstream oil projects with foreign involvement.

Table 5: Turkmenistan's PSAs with foreign companies

Foreign partner	Partner's home country	Oil field(s)	Location	Production in 2003 (mn bbls)	Production in 2003 ('000 bpd)	Investment	Investment date range
Burren Energy	UK	Nedit Dag	Onshore	28.0	77	$200	1997-2003
Dragon Oil	UK/UAE	LAM & Zhdanov	Offshore	4.8	13	$315	1993-2003
Mitro	Austria	E. Cheleken	Onshore	2.2	6	$55	
Petronas Carigali	Malaysia		Offshore	0.0	0	$190	1996-2003
Maersk	Denmark		Offshore	0.0	0	$10	2003
Total				35.0	96	$770	

Source: Upstream, 20 May 2004

Turkmenistan's oil production has struggled to reach 200,000 bpd (10 mn T/yr), although official plans have consistently targeted much higher output rates. Modest growth in oil output is expected to the end of the decade as additional offshore production offsets declines at some of the country's older fields. Oil will continue to be exported across the Caspian Sea to Iran and to export terminals in Georgia via Azerbaijan. We do not expect to see the construction of oil export pipelines from Turkmenistan.

After an attempt to break its dependence on Gazprom and the Russian gas market in 1997, when Turkmenistan felt that the price it received from Gazprom was too low, Turkmenistan was forced to concede defeat and turn back to Moscow as its only realistic market for significant gas export volumes. Gazprom was able to sign a long-term supply agreement with Turkmenistan for the delivery of gas through the Central Asia-Centre gas pipeline corridor. Turkmenistan again cut off deliveries to Russia at the start of 2005 in another disagreement over pricing. At the time of writing the issue remains unresolved, with Turkmenistan seeking a price of \$60/'000 m^3, while Russia is offering \$44/'000 m^3, which it says is the price that had already been agreed for deliveries between 2004 and 2006.

Turkmenistan continues to harbour ambitions to build a gas export pipeline across Afghanistan to Pakistan and India. Questions have been raised over the country's ability to supply sufficient volumes of gas to fill such a line and meet their commitments on long-term gas deliveries to Russia. Any such project would also have to overcome the difficult

[17] 'The long shadow of dictatorship', Upstream, 20 May 2004.

political relations between the two intended consumers as well as competition from Iran, which would like to build its own (shorter) gas export pipeline to Pakistan and India.

2.4.4 Uzbekistan

Uzbekistan's upstream oil and gas industry has attracted little foreign interest since the country's independence from the Soviet Union in 1991. After the break-up of the FSU oil production increased from around 50,000 bpd to almost 200,000 bpd by 1995. This production level could only be sustained for a few years and output began to fall again at the end of the 1990s. It is now estimated at around 170,000 bpd.

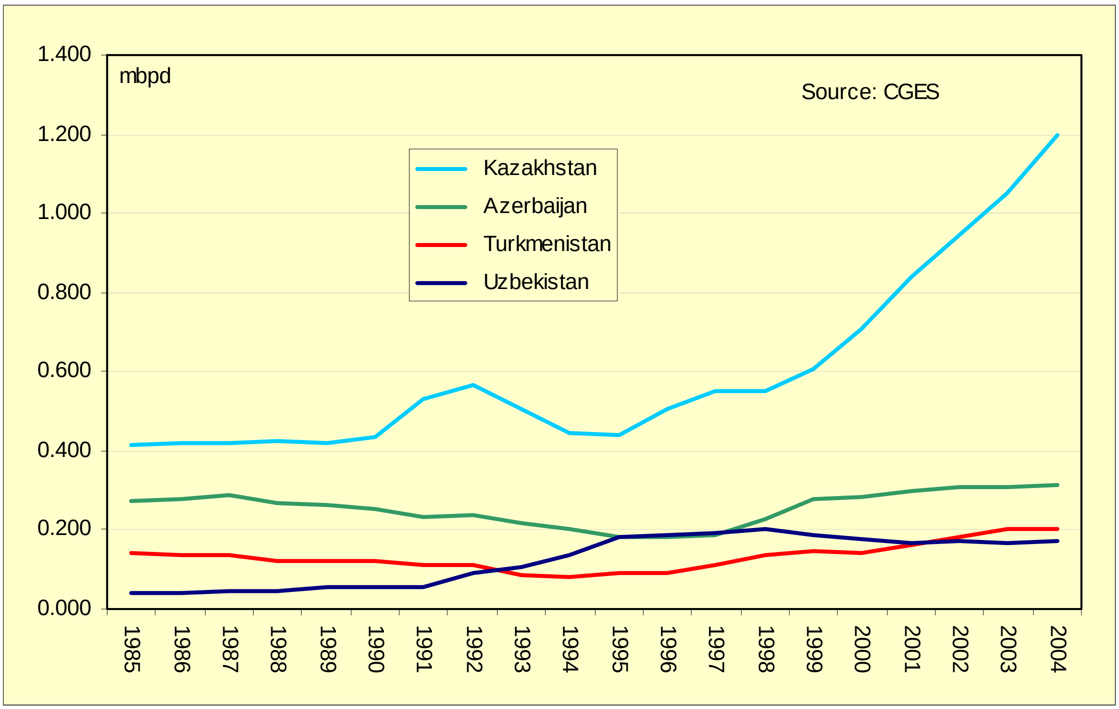
Uzbekistan has identified a need for foreign investment in the country's upstream oil and gas sector to stem the decline in output and has been looking at the partial privatisation of Uzbekneftegaz, following an audit by Ernst and Young. The country has also been considering changes to the legal framework for the oil and gas sector.

In 2001, Trinity Energy, a small UK-based oil company, signed a 40-year PSA to prospect for and produce oil and gas in the centre of the Ust-Yurt plateau and the south-western Hissar region and to develop the Adamtash condensate field and the Yuzhny-Kyzylbairak oil field.[18] In July 2004, Russian company SoyuzNefteGaz, headed by former Russian energy minister Yuri Shafranik, acquired a controlling stake in UzPEC, the company created to operate the PSA, continuing a trend of Russian investment in oil and gas projects in Uzbekistan which has seen companies such as Lukoil and Itera investing in the republic. In late-February 2005 the Uzbek government revoked the PSA, claiming that UzPEC had failed to fulfil its contractual obligations.

In June 2004, Lukoil signed a 35-year PSA covering gas production in the Bukhara-Khiva region in southwest Uzbekistan.

[18] 'Trinity Energy to explore and develop fields in Uzbekistan', Alexander's Oil & Gas Connections, 05 May 2001.

Figure 10: Oil production in the Caspian Sea region (1985-2004)



2.4.5 State-owned companies in the Caspaian Sea Region countries

State-owned companies continue to play a major role in the oil and gas industries of the Caspian Sea Region countries, as operators of upstream projects, owners and managers of transportation networks, as well as regulators of private-sector involvement in the sector. Commercialisation/restructuring of these companies is only likely to proceed if the governments of the countries concerned deem it beneficial and it will remain extremely difficult for the Bank to drive commercialisation/restructuring of large state-owned companies in the absence of such government support. Azerbaijan appears to be moving in this direction, but the same cannot yet be said of Kazakhstan, Turkmenistan or Uzbekistan. The Bank's current policy of seeking to ring fence projects it supports and to work with commercialising subsidiary companies, rather than attempting to tackle the core company would seem to offer the best long-term hope both for securing projects and for the ultimate commercialisation of state-owned companies. Working with subsidiaries in this way can perhaps provide valuable demonstration effects, which may in time lead to greater acceptance of the concept of commercialisation on a bigger scale.

2.5 Oil and gas transportation in Russia, the FSU and Central and Eastern Europe

The one area of the Russian oil industry that has remained firmly under central government control is the oil pipeline network, owned and operated by Transneft (crude oil pipelines) and Transnefteproduct (refined product pipelines). This situation is unlikely to change, since senior Russian officials from President Putin down have stated that the country's pipeline network will remain the exclusive preserve of the state-owned monopolies.

The oil and gas pipeline network of the former Soviet Union and Eastern Europe reflected the needs to a unified entity (the Soviet Union and its satellite states) not those of a group of independent countries pursuing their own oil and gas production and export policies.

The oil pipeline network was designed to carry crude oil from the major oil-producing regions of West Siberia and the Volga-Urals region to refineries in Russia and other FSU republics and to client states in Eastern Europe as well as to export terminals on the Baltic Sea and Black Sea coasts of the Soviet Union for onward delivery to customers in Western Europe and beyond. With the break-up of the Soviet Union, all of the Baltic Sea export terminals and all but two of the Black Sea terminals ended up outside the borders of Russia. As a result, much of Russia's crude oil exports had to cross the territory of other FSU republics as transit countries.

Since the mid-1990s, Russia's oil pipeline policy has had two major goals. Firstly, Transneft has sought, successfully, to boost its capacity to move crude oil out of Russia in line with increases in Russia's oil production. Secondly, Transneft has sought, again with significant success, to reduce its dependence on FSU transit countries for crude oil exports. To this end, the company built the 260-km Sukhodolnaya-Rodionovskaya pipeline in 2001, allowing Russian oil destined for Novorossiysk to avoid crossing Ukraine.

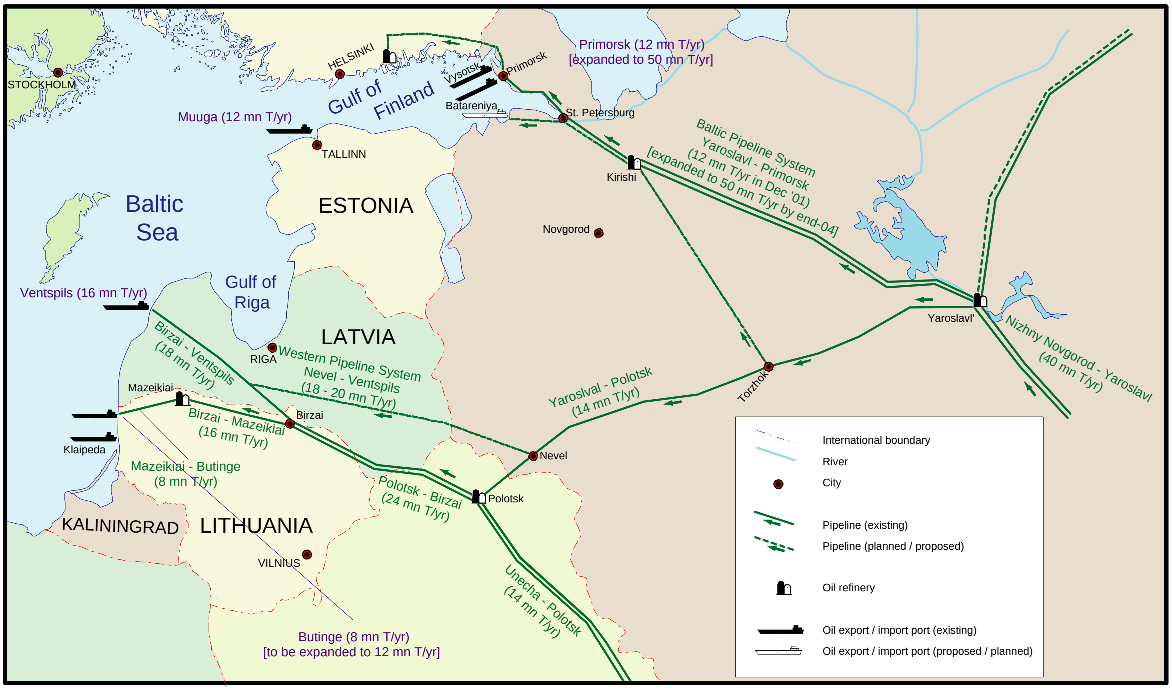
Figure 11: Transneft's Ukraine bypass pipeline

Source: Lee (1997)

The same year, the company completed construction of the Baltic Pipeline System (BPS), which initially ran from Kirishi to a new oil export terminal at Primorsk on Russia's Baltic Sea coast. Between June 2003 and December 2004 the capacity of the BPS was increased from 240,000 bpd (12 mn T/yr) to 1 mbpd (50 mn T/yr), allowing Transneft to avoid exporting oil via the Latvian port of Ventspils and putting pressure on the Lithuanian oil export terminal at Butinge. The expansion of the BPS involved work on the Yaroslavl-Kirishi leg of the pipeline in addition to that between Kirishi and Primorsk.

Major oil export pipeline projects proposed by Russia's oil companies have not found favour with Transneft. A proposal by Yukos to build an oil export pipeline from Angarsk in East Siberia to China was opposed by Transneft and was subsequently dropped in favour of Transneft's own proposal for a much longer and more expensive export pipeline to Russia's Pacific coast (with a possible spur running southwards into China). Similarly, proposals put forward by Lukoil for a major new oil export pipeline to a deep-water, ice-free export terminal at Murmansk on Russia's north coast were opposed by Transneft, largely because it saw the route as competition for the BPS. Transneft is now talking with Lukoil about a much smaller northern export route, possibly running from Kharyaga to Indiga.

Figure 12: Transneft's Baltic Pipeline System



Source: adapted from Lee (2005)

While Russia's oil companies have been prevented from competing with Transneft in the construction and ownership of major oil export pipelines, they have been able to build and operate their own small oil terminals and, in the case of Lukoil, a pipeline to serve the terminal. Should oil companies continue to face restrictions in the volume of oil that they are able to export through the Transneft system, it is expected that more private ports will be built by Russia's oil companies.

In 2003, Lukoil began adding several new oil export terminals of its own, including Varandei on the Pechora Sea, Vysotsk on the Gulf of Finland, Izhevskoye at Kaliningrad on the Baltic and Ilinka, close to Astrakhan on the north coast of the Caspian.[19] In January 2004, Rosneft opened up a new northern export route from Russia involving shuttling oil from a new export terminal at Arkhangelsk to a storage and offloading facility at

[19] 'Lukoil is quietly adding its own export capacity', J Lee, FSU Pipeline Advisory Service, 2 Oct 2003.

Murmansk for consolidation into large cargoes suitable for trans-Atlantic delivery in VLCCs.[20]

Russia's natural gas pipelines are also a state monopoly and are almost certain to remain so. Unlike the oil pipelines, which are owned and operated by a dedicated pipeline company, Russia's natural gas pipelines are owned and operated by the country's largest gas producer, raising concerns over third-party access. The gas pipeline network, like its oil counterpart, was designed to meet the needs of the Soviet Union as a whole, rather than those of its constituent republics. The system was designed to carry gas from producing regions in the northern part of West Siberia and the southern part of Central Asia to consumers in western Russia and to export markets in Europe.

While Gazprom, like Transneft, has been confronted with having to deal with a number of new transit countries in its gas export business, the response to the problem has been slightly different. Gazprom has been more aggressive than Transneft in taking control of gas pipelines on the territories of other FSU countries. This has often been accomplished through a debt for equity swap after the transit countries ran up huge arrears in their payments for gas delivered to them by Gazprom.

The problems faced by non-Russian oil and gas producers have resulted from their total dependence on export routes across Russia for their oil and gas. The situation for non-Russian hydrocarbons producers has improved somewhat in the case of oil, but little progress has yet been made in diversifying gas export routes and this will be a major challenge for the future.

Azerbaijan was adamant from the very beginning of its independent existence that new oil export pipelines would not cross Russian territory. To this end, the Baku-Supsa oil export pipeline was built to carry 'Early Oil' from the ACG project and is now being followed by the Baku-Tbilisi-Ceyhan (BTC) pipeline.

Due to its geographical position, Kazakhstan has not been able to break its dependence on oil export routes crossing Russia. The Caspian Pipeline Consortium's export route from Tengiz to the Black Sea crosses Russia and while the operation of the pipeline is controlled by the shareholders (of which the Russian government is just one), the route has still come under pressure from Russia, which is dragging its feet over approval for the expansion of the line's capacity, which will be needed to accommodate rising production from the Tengiz oilfield.

Proposals to build oil and gas export pipelines beneath the Caspian Sea to deliver oil from the Kashagan field to the BTC pipeline have come to nothing, partly as a result of the difficult physical conditions, partly through lack of any pressing volume constraints and partly as a result of the division of the north Caspian, which would require multi-lateral agreement for such pipelines to be built. Russia has indicated that it would oppose their construction. Russian opposition to a subsea pipeline across the Caspian Sea from Kazakhstan to Azerbaijan suggests that exports of oil from Kashagan via the BTC pipeline will, initially at least, be delivered to a terminal close to Baku by tanker, rather than by pipeline[21]. The governments of Kazakhstan and Azerbaijan are also keen to push for the

[20] 'Rosneft adds to northern export capacity', J Lee, FSU Pipeline Advisory Service, 16 Jan 2004.
[21] Lee (2005-2)

use of the BTC pipeline for Kashagan oil exports. An inter-governmental agreement paving the way for the use of the BTC pipeline for exports of Kashagan oil is due to be signed in September 2005 and the issue was discussed by the presidents of the two countries when they met in Baku during President Nazarabayev's visit in April.

It is envisaged that around 500,000 bpd of oil from Kashagan could be exported via the BTC pipeline. Oil from the field is likely to be piped ashore in Kazakhstan and delivered to an export terminal at Aktau. From there, it will be transported across the Caspian Sea by ship to a new receiving terminal in Azerbaijan that will be linked to the BTC pipeline. At present, shipments of oil between Kazakhstan and Azerbaijan are made in 12,000 dwt vessels, but it is envisaged that a new fleet of five 60,000 dwt vessels will be constructed to handle exports of oil from Kashagan. It is estimated that the cost of establishing the Aktau-Baku export route, including the construction of 700 km of pipeline in Kazakhstan, terminals at Aktau and Baku, a pipeline link from the Azerbaijani terminal to the BTC pipeline and the dedicated vessels to carry oil across the Caspian Sea, will be in the region of $3 bn.

Using the BTC pipeline to export oil from Kashagan as well as supplies from the ACG project in Azerbaijan will require a significant expansion of the route's capacity and plans for this are already being drawn up. A capacity increase of approximately 250,000-350,000 bpd (12.5-17.5 mn T/yr) can be achieved through the addition of drag reducing agents, with a further 500,000 bpd (25 mn T/yr) coming from pipeline looping and additional pumping stations. The inclusion of Kashagan oil in the BTC export stream will also alter the specification of the BTC export grade. While Kashagan oil is likely to be lighter than Azeri Light from the ACG fields (42-45° API compared with 34.9° API), the sulphur content will be significantly higher. Azeri Light has a sulphur content of 0.14% by weight, whereas output from Kashagan contains a significant amount of sour associated gas with a sulphur content of up to 23%. Kashagan development plans include the re-injection of sour gas to maintain reservoir pressure, but residual sulphur levels in the crude oil export stream are still likely to be much higher than those for Azeri Light. The Tengiz export stream, for example, has a sulphur content of 0.55% by weight.

A study on alternative routes for the transportation of Kazakhstani oil from Aktau to the Baku-Tbilisi-Ceyhan pipeline, carried out in 2002 by Gulf Interstate Engineering[22], recommended the use of barges for volumes of up to 150,000 bpd (7.5 mn T/yr), but the construction of a subsea pipeline for volumes in excess of that. The preferred pipeline route ran between Aktau and Makhachkala in Russia and then utilised the southern portion of the Baku-Novorossiysk pipeline to carry oil southwards to join the BTC pipeline. A second alternative envisaged the construction of a pipeline along a similar route from Aktau to Khudat in Azerbaijan, which would avoid transiting Russian territory. More recent discussions seem to have centred on the transportation across the Caspian Sea by ship of much larger volumes than envisaged in the 2002 study, since Russia is expected to oppose the construction of subsea export pipelines linking Kazakhstan and Azerbaijan.

No progress has yet been made in diversifying gas export routes from Central Asia, which remains almost totally dependent on the Central Asia-Centre pipeline system that runs northwards to Russia (there is a small export pipeline with a capacity of 8 bcm/yr linking Turkmenistan and Iran). To the west of the Caspian Sea, construction has begun on the

[22] Gulf Interstate Engineering (2002)

South Caucasus Gas Pipeline to carry gas from Azerbaijan's Shah Deniz field to Georgia and Turkey.

It is notable that all the new oil and gas export pipelines built to date, whether in Russia or the Caspian Sea region countries, have been directed westwards. The next phase of development of the region's major hydrocarbons export network is likely to focus on the East. Russia's Taishet-Nakhodka oil export pipeline will target markets in Japan, Korea, China and possibly the west coast of the USA. Kazakhstan has begun construction of an oil pipeline to link its eastern trunk oil pipeline to China, opening up a route for exports of both Kazakhstani and Russian crude into western China. BG and its partners at the Karachaganak field are considering a gas pipeline across Kazakhstan to China, although this is only one of many options being considered for gas utilisation[23] and there is still talk of a possible gas pipeline into China from Turkmenistan. Central Asia's largest gas producer has also revived plans for a gas export pipeline across Afghanistan to Pakistan and India, although the project remains hampered by the political tensions between the target customers and the political/security situation in Afghanistan. The long-term supply contracts that Gazprom has signed with Turkmenistan, which envisage deliveries of up to 80 bcm/yr between 2010 and 2028, have led some to question whether Turkmenistan will sufficient gas production capacity to fill a trans-Afghan pipeline as well.

In Central and Eastern Europe a number of cross-border pipelines have been proposed, most designed to divert oil traffic away from the Turkish Straits (the Bosphorus and Dardanelles). These projects include the Burgas-Vlore oil pipeline crossing Bulgaria, the former Yugoslav Republic of Macedonia (FYROM) and Albania, the Burgas-Alexandroupolis Pipeline linking ports in Bulgaria and Greece and the Constanta-Trieste pipeline, which is planned to cross Romania, Serbia-Montenegro, Croatia and Italy. All are planned to carry oil from the Black Sea to the Mediterranean or to pipelines serving refineries in Central and Western Europe and each would help to reduce the volume of oil passing through the environmentally sensitive Turkish Straits. Each of these pipelines will pass through transition countries and, particularly in the case of the Constanta-Trieste pipeline, require several billions of Euros of investment. The Bank's previous experience in the BTC project places it in an ideal position to participate in the funding of any of these proposed pipelines and its involvement would bring real benefits both in terms of providing comfort to commercial lenders and to ensuring that the highest environmental standards are observed.

The Nabucco gas pipeline project is a 3,400-km pipeline intended to carry gas produced in the Middle East, the Caspian Sea region and Possibly Russia from Turkey to Austria through Bulgaria, Romania and Hungary. The estimated cost of the line's construction is €4.4 bn, which will require significant international funding and create a role for the Bank following its involvement in the South Caucasus Gas Pipeline project.

2.6 OIL REFINING

Traditionally, the oil refining sectors of the republics of the former Soviet Union and the countries of Central and Eastern Europe were designed primarily to meet domestic demand, with surpluses of unwanted, often heavier, products being exported to Western

[23] 'Harnessing the potential of Karachaganak', a presentation by Larry Andersen, President and Asset General Manager, BG Kazakhstan, to IP Week, 15 February 2005.

Europe. However, the collapse in oil demand in the region following the break-up of the Soviet Union in 1991 resulted in massive over-capacity and under-utilisation of refining assets.

Over the past five years or so, considerable investment has been made by the new owners of oil refineries in Russia, the other republics of the FSU and the countries of Central and Eastern Europe in upgrading outdated plant, adding de-sulphurisation capacity and catalytic cracking capabilities to produce larger proportions of higher value, light products such as gasoline. Nevertheless, refinery utilisation in Russia remains well below levels reached in the West, with capacity utilisation typically under 70%, compared with over 90% in Europe and the US.

Figure 13: Russian refinery output of major products

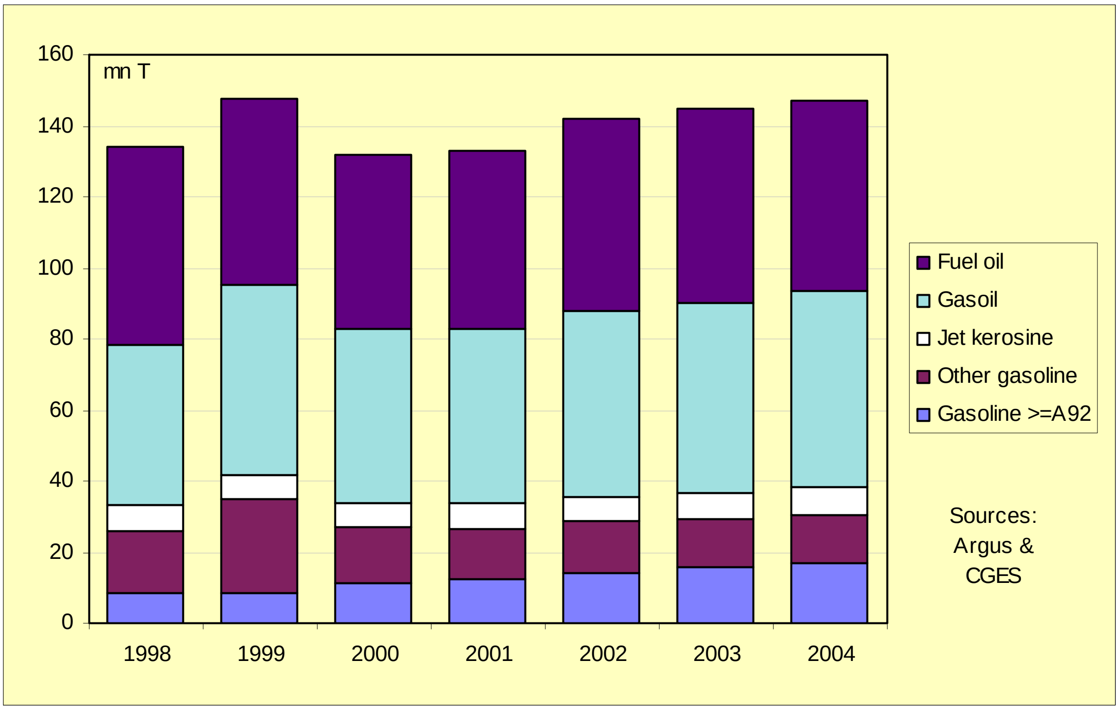
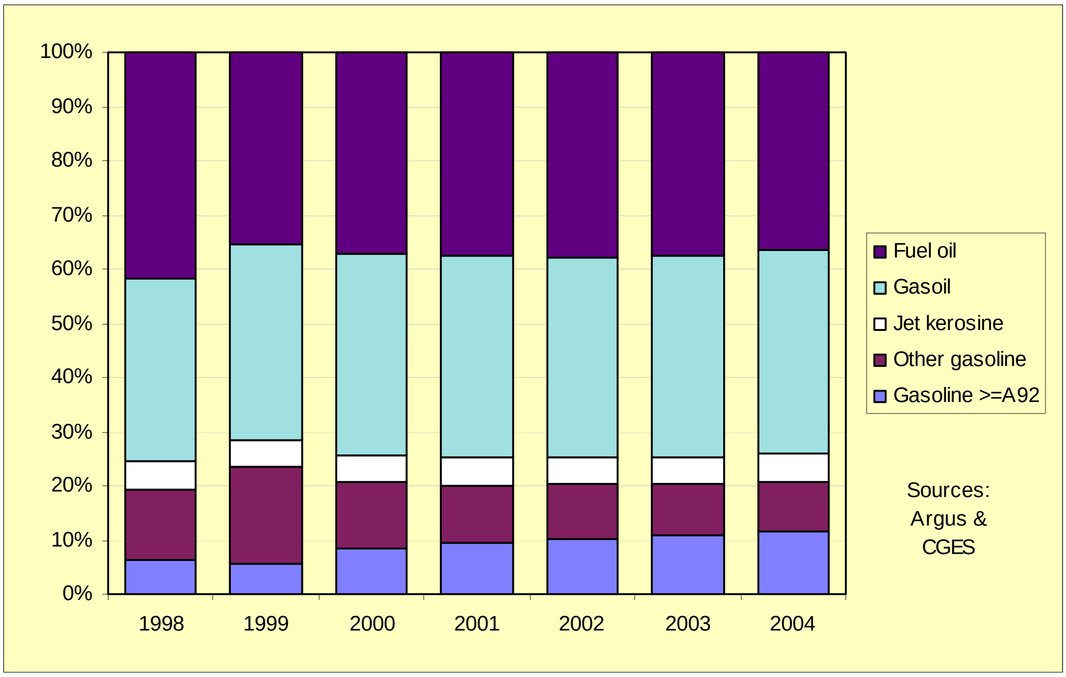
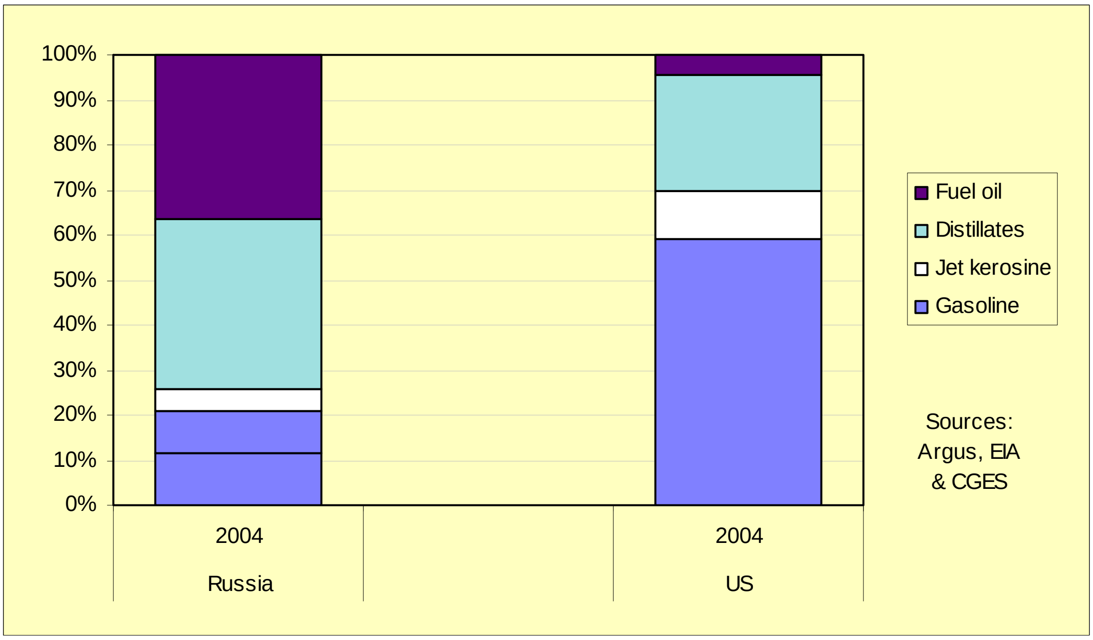


Figure 14: Shares of major product groups in Russian refinery output



Despite the upgrading work that has already been undertaken at several of Russia's refineries, the proportions of the various product groups in total Russian refinery output remains little changed. Heavy fuel oil still accounts for close to 40% of all products produced, with gasoil accounting for a similar proportion. The output of high-octane gasoline has risen, though, increasing from 6.5% in 1998 to 11.5% in 2004, although total gasoline production has continued to account for a relatively stable 20% of refinery output. In contrast, almost 60% of the output from US refineries in 2004 was gasoline, with distillates (gasoil and diesel fuel) accounting for 26% and fuel oil just 4%.

Figure 15: Output from US and Russian refineries compared



The republics of Central Asia and the Caucasus have lagged behind in the upgrading of refineries, with many plants little changed from the Soviet era, although this is slowly beginning to change. In Azerbaijan, Socar is planning to upgrade its refineries in Baku to produce products that meet international specifications.

2.7 REGIONAL RELATIONS

2.7.1 Avoiding transit countries

A key feature of Russia's oil transportation policy in recent years has been to reduce the country's dependence on transit countries to move its oil to export terminals (see 2.5 above). Decisions on the construction of major new oil and gas export routes appear to have had more to do with avoidance of transit countries than with simple economics of export shipments. The Baltic Pipeline System (oil) and the Blue Stream Pipeline (gas) are both good of examples of this policy in action. The former reduced dependence on Latvia and Lithuania for Russian oil exports through the Baltic Sea, while the latter created a gas export route to Turkey (and perhaps eventually Southern Europe) that avoided Ukraine, Romania and Bulgaria. Keeping transit fee revenue within Russia has been more important than reducing such costs to a minimum. For Russia, such concerns are expected to continue to inform oil export pipeline policy choices. The Russian decision to build the Baltic Pipeline System resulted in part from the fact that oil exporters had faced high transit and port fees charged by Latvia on oil exported via Ventspils. However, as the International Energy Agency pointed out in its 2002 Russia Energy Survey[24], Latvia itself had developed a project to raise the pipeline capacity serving Ventspils (the Western Pipeline System), which would have been far more cost effective than the Baltic Pipeline System and would have required a much smaller initial investment of around $120 mn for pipeline, port and terminal facilities, compared with the $460-mn cost of the first phase of the Baltic Pipeline System. A study carried out for the World Bank in 1997 appears to confirm that the Baltic Pipeline System, at least, was not a least cost solution to problem of oil exports through the Baltic Sea. Netback values calculated for various export options show the cost of exporting oil from Timan Pechora to Rotterdam via the Baltic Pipeline System to be $2.50/bbl higher than the cost of exporting the same oil via Ventspils.[25]

For other oil-producing countries in the FSU, avoidance of transit countries for their oil exports is impossible, since all are landlocked. However, in some cases there has been a determination to avoid crossing Russian territory. Azerbaijan, strongly supported by the US government, has followed a policy of avoiding the construction of major new export pipelines for oil and gas across the territory of Russia. A similar policy has not been possible for Kazakhstan, given its location, its long border with Russia and its large ethnically Russian population. Kazakhstan's dependence on Russia as a transit route for its oil exports has caused some difficulties in the past and continues to do so as far as the CPC pipeline from Tengiz to the Black Sea is concerned. The Russian government is unhappy with the return it is receiving from its investment in the pipeline and is blocking proposals to expand the route's capacity until it wins agreement for an increase in transit tariffs along the route.

[24] IEA (2002) p98.
[25] World Bank (1997), p166.

2.7.2 Alternative sources of supply

Security of oil and gas supplies has become a major concern for republics of the FSU and for former satellite states in Central and Eastern Europe. All are dependent to a significant degree on energy supplies (particularly of natural gas) from Russia, or that must transit Russia. As Leijonhielm and Larsson[26] point out, the Baltic States, Bulgaria, Croatia, Finland, Greece and Slovakia are most at risk, relying on Russia for 100% of their supplies. They also point out that Moldova and Belarus are highly dependent on gas supplies from Russia, but what they do not go on to say is that even those gas supplies to these two countries that do not originate in Russia have to pass through the country. Leijonhielm and Larsson's study enumerates many examples of Russia using gas supplies to neighbouring countries as a lever to gain political and/or economic influence over former satellite states. Georgia, Ukraine, Moldova and the Baltic republics are all identified as having suffered in this way. Recently, oil supplies to Lithuania's Mazeikiai refinery and Butinge export terminal have been reduced as Transneft has expanded capacity on its Baltic Pipeline System.

While oil supplies can usually be replaced with purchases from other suppliers such a switch is not without cost. Pipeline deliveries of Russian crude to refineries in Central and Eastern Europe are generally at prices well below those earned in Northwest Europe or the Mediterranean. In 2004, the average price of Urals crude delivered to the Czech Republic through the Druzhba (Friendship) pipeline was $2.50/bbl below the Urals price in either the Mediterranean or Northwest European markets. In the gas of gas, securing alternative supplies is generally impossible, since the only pipelines are those carrying gas from, or through, Russia.

While some refiners, most notably those close to ports through which they can import oil, have sought alternative sources of crude oil to supplement supplies of Russian crude, most have sought to secure oil supplies through strategic relationships with Russian partners, or through the sale of a stake in the plant to a Russian oil company. Thus, Lukoil, Slavneft, TNK-BP and Yukos all control refining assets outside Russia in state of the FSU or Eastern Europe. These relationships guarantee a supply of crude oil for the host country (it is hoped) and investment in upgrading the refineries. For the Russian companies they provide an increased export allocation, since deliveries to these refineries generally fall outside their export quota allocations. They also provide a route for boosting crude oil exports, with some of the crude that is supposedly to be refined actually being exported by the refinery in its unprocessed state.

Security of energy (oil and gas) supplies in the energy-poor countries in the Bank's area of operations could perhaps be enhanced by the development of a truly competitive energy sector in Russia. However, this would have to include real competition to Gazprom and the removal from state control of oil pipeline operator Transneft. In the cases of both oil and gas the trunk pipeline network would have to be operated on an open-access basis, free from any political influence over oil and gas transportation. It seems unlikely that this will happen in the foreseeable future. Control over oil and gas supply through its pipeline system is too important a tool for regional policy and for regulation of the oil industry for the Russian government to be prepared to forego it any time soon.

[26] Leijonhielm and Larsson (2004)

2.7.3 Cross-border oil and gas projects

Cross-border oil and gas projects (those involving the development of an oil or gas field that straddles an international border) have become an increasingly important issue for the states of the FSU, particularly in the Caspian Sea region. Following the agreement between Russia and Kazakhstan on a mutual border in the Caspian, a number of geological structures straddling the border were identified for joint exploration and development by Russian and Kazkahstani companies. These projects could help to cement ties between the two countries, or they could become the source of lengthy disputes. Initially it seemed as though the former would be the case, with quick agreement on which companies would be responsible for leading the project on each of the identified blocks. However, since then Russian companies have sought tax breaks from the government of Kazakhstan and little real progress has yet been made on any of the projects.

Elsewhere, conflicting claims to a field in the south Caspian between Azerbaijan and Turkmenistan have led to repeated flare-ups between Baku and Ashgabad. The field, called Kapaz in Azerbaijan and Serdar in Turkmenistan, has repeatedly been the subject of dispute between the two countries. In 1997, Azerbaijan's Socar signed a deal with Russia's Lukoil and Rosneft to develop the field, which was annulled in the wake of protests from Turkmenistan. In 1998-99, Turkmenistan sought to involve US oil major Mobil in a project to develop the field, but this deal also lapsed. In January 2005, Turkmenistan again sought to involve foreign partners in the development of Serdar, granting exploration rights to Canadian oil company Buried Hill Energy, which was represented in discussions with the Turkmenbashi by former Canadian Prime Minister Jean Chrétien. Turkmenistan has also laid claim to the Azeri and Chirag fields (known in Turkmenistan as Khazar and Osman), currently being developed by a BP-led consortium under a PSA signed with Azerbaijan. In the case of these two countries, cross-border oil and gas projects have been a source of conflict, rather than of co-operation, and seem likely to remain so.

3 POSSIBLE AREAS OF OPERATION FOR THE EBRD IN THE UPSTREAM OIL AND GAS SECTORS OF THE FSU

3.1 RUSSIAN OIL AND GAS EXPLORATION/EXTRACTION PROJECTS

While the major Russian oil companies are expected to fund most of their upstream oil and gas projects internally, or through commercial borrowing from Russian and Western banks, there could be a role for the EBRD in the financing of particularly large and/or complex projects in remote areas. Possible examples include the Shtokman gasfield in the Barents Sea and future projects off Sakhalin Island. The size, complexity and environmental sensitivity of such projects provide the Bank with an opportunity to give a lead to commercial banks in such projects, utilising its experience in dealing with such issues and its track record of ensuring that environmental responsibility is built in as a key feature of any such project.

The Bank should continue to be actively involved in upstream oil and gas projects in its countries of operation. This involvement should include both brownfield projects and new, greenfield projects, where the external scrutiny brought to bear by the Bank's involvement is extremely valuable in minimising detrimental environmental and social impact. Obvious examples of large-scale projects that the Bank might be asked to become involved in are Kashagan and Karachaganak in Kazakhstan, ACG and Shah Deniz in Azerbaijan, Sakhalin Island projects, Kharyaga, Kovytka, Shtockmanskoye, Prirazlomnoye and Astrakhan in Russia, among others.

The author's conversations with the private banking sector[27] suggest that the Bank is seen as having an important role to play in leading the way in providing financing structures to the Russian oil industry that the commercial banks by themselves would not offer. A key example is project financing, which the commercial banking sector has yet to get involved in. The presence of the EBRD in syndicated project finance deals, perhaps with smaller Russian oil companies, would provide a lead to the commercial banking sector, fitting the Bank's requirement for additionality. The Bank would also be in a position to ensure that any such projects were monitored for corporate governance and for their environmental impact, both in terms of greenhouse gas (GHG) emissions and in terms of local impact. The Bank should continue to support smaller players in the upstream oil sectors of its countries of operation. The Bank has given a lead to commercial lenders in Russia and can continue to do so by actively supporting smaller projects and providing a degree of comfort to commercial lenders in this area.

Structured trade finance/Pre-export finance deals between Russian companies and foreign banks have become well established in recent years, but they remain limited to the larger Russian companies. The Bank could play an important role in shifting the access to finance down the hierarchy of oil companies in Russia to some of the smaller players, again providing a lead to the commercial banking sector.

State-owned companies will continue to play a major role in the upstream oil and gas industries of Russia and the Caspian Sea region and the Bank should continue to work with state-owned companies in this sector. As a long-term aim, the Bank should continue to seek the possibility of transition through the restructuring, commercialisation and

[27] Conversation with Andreas Schwung of Commerzbank during IP Week 2005.

increased transparency of these companies. Their eventual privatisation might be a desirable goal, although the likelihood of realising this appears slim at the present time.

Natural gas is a fuel that is growing in importance internationally as a result of its relatively better environmental credentials than oil and because of the more diversified location of reserves. Russia and the Caspian Sea Region countries are well endowed with gas reserves and the Bank should actively support projects, both large and small, to commercialise these gas reserves. Projects such as Shtockmanskoye, Kovytka and Astrakhan mentioned above are examples of where the Bank might become involved.

Table 6: Structured trade finance deals with the Russian oil & gas sector

Transactions closed in 2003		Transactions closed in 2004	
Borrower	**US$ mn**	**Borrower**	**US$ mn**
TNK	100.0	Gazprom	50.4
Khancheyneftegaz	5.0	Gazprom	10.0
KMOC	40.0	LUKoil	100.0
TNK	200.0	LUKoil	150.0
TNK	400.0	Rosneft	150.0
Petrosakh	30.0	Archneftegeologya	25.0
Rosneft	500.0	Gazprom	200.0
Gazprom	215.0	Gazprom	1,100.0
LUKoil-Perm	80.0	Tatneft	187.5
Rosneft	265.0	Ritek	150.0
Transnefteprodukt	75.0	Rosneft	500.0
Sibneft	412.0	Gazprom	200.0
Yukos	1,000.0	TNK	1,000.0
Rosneft	150.0	Varyegannefty	200.0
LUKoil	765.0	Rosneft	800.0
Gazprom	300.0	Gazprom	1,100.0
		Petrol Complex	250.0
		Sibneft	160.0
Total	**4,537.0**	**Total**	**6,332.9**

Source: Loanware/Commerzbank

3.2 CASPIAN SEA REGION OIL AND GAS EXPLORATION/EXTRACTION PROJECTS

Although the big increases in both Azerbaijan's and Kazakhstan's oil production are expected to come from a small number of large projects, the upstream oil and gas sector of both countries has also attracted a growing number of smaller participants. As in Russia, it is perhaps among these smaller players that the EBRD has a most positive role to play.

In Kazakhstan, privately-owned oil companies have from time to time come under immense pressure from branches of the government or individuals with close connections to the levers of power in the country. While such unwelcome attention has not been restricted to the smaller companies, they are less able to withstand such pressures than their larger counterparts whose projects are of greater significance to the country.

Involvement of the Bank in smaller projects in both Azerbaijan and Kazakhstan, while possibly exposing the Bank to greater country risk, might help to ensure that the rule of law is more universally applied.

The challenges facing the Caspian Sea region countries in utilising their natural gas resources are greater than those in Russia given the relatively undeveloped nature of their domestic gas markets and their distance from export markets. Nevertheless, but domestic gas utilisation projects could provide worthwhile areas of involvement for the Bank in these countries. Karachaganak in Kazakhstan and Shah Deniz in Azerbaijan are obvious examples of projects in which the Bank should remain involved.

3.3 OIL AND GAS TRANSPORTATION PROJECTS

The Bank should continue to actively support cross-border pipelines to carry oil and gas from fields to market. Landlocked oil and gas-producing countries have greatly benefited already from the Bank's involvement in such projects and will continue to do so. The Bank can help to ensure the safe, fair and sustainable transportation of hydrocarbons to market through transit countries and should continue to do so.

Potential projects for the Bank's future involvement include the expansion of existing pipelines (BTC and CPC), the construction of pipelines to bypass the Turkish Straits (Burgas-Alexandroupolis and AMBO), the Nabucco gas pipeline from Turkey to Austria, northern export routes in Russia, the planned Taishet-Nakhodka pipeline to carry Russian oil to Asian markets, planned oil and gas pipelines between Kazakhstan and China and, perhaps, a gas pipeline from Turkmenistan to India and Pakistan.

Oil and gas transportation projects are likely to include the need to upgrade existing, or build new, port and storage facilities. This would provide additional opportunities for the Bak's involvement.

3.3.1 Russian oil and gas transportation projects

Major oil and gas pipeline projects in Russia will continue to be carried out by Transneft (oil) and Gazprom (gas), rather than by the private oil companies operating in Russia. Transneft is expected to seek external financing for some of the cost of building the Taishet-Nakhodka pipeline, the cost of which is currently estimated at $11-12 bn, but this is likely to come in the form of soft loans from the Japanese government, rather than commercial lending from international banks.

Smaller export terminal projects carried out by privately-owned Russian oil companies tend to be funded internally. However, Lukoil has announced that it intends to go ahead with the expansion of its Varandey terminal on Russia's north coast and the pipeline serving it, aiming to boost capacity to 12 mn T/yr (240,000 bpd) by 2007. As yet there is no indication of how this project will be funded.

It has been suggested that the Bank might have a role to play in the development of quality banks for crude oil exports, this could be particularly relevant for the Transneft oil pipeline network, where all crude oil inputs to the system are blended into the standard Russian export grade (commonly known as Urals). Shippers currently lift oil and a barrel-for-barrel basis, with no account taken of the quality of their inputs to the pipeline system. Some of the higher quality Russian oil is exported as a separate stream of Siberian Light oil via the Black Sea port of Novorossiysk.

The possibility of introducing a quality bank on the Transneft pipeline network has long been under discussion in Russia, but there are concerns over the impact such a development would have on some regions of the country, most notably the largely-muslim republics of Tatarstan and Bashkortostan. Transneft sought to introduce a ‘shadow’ quality bank at the beginning of 2003 in order to demonstrate how the system would work. The pipeline monopoly proposed a scale of compensations/penalties for producers of different grades of oil based on a mechanism that had been created several years previously (see Table 7).

Table 7: Compensation/penalties under Transneft's quality bank proposal ($/tonne)

Producer	Compensation /penalty
Rosneft	2.46
TNK	1.07
Sibneft	1.06
Lukoil	0.87
Slavneft	0.57
Sidanco	-0.19
Surgutneftegaz	-0.52
Yukos	-0.58
Tatneft	-4.05
Bashneft	-5.54

Source: Argus FSU Energy 13/12/2002 p5

Under the proposed quality bank system state-owned Rosneft would be the biggest winner, while regional producers Tatneft and Bashneft would be the biggest losers. The introduction of a quality bank on the Transneft pipeline system requires the approval of all the system’s users, which Transneft was unable to secure – Tatneft and Bashneft, not surprisingly, opposing the system

Transneft views any decision on the introduction of a quality bank as lying with the Federal Government, rather than with the company, as the following question and answer from a 2002 internet press conference with Transneft President Simon Vainshtock[28] shows:

> **A. Sharvaeva: When do you think the crude quality bank will be created? Won’t it entail bankruptcy of small companies producing crude with high content of sulphur?**
> S. Vainshtock: This is a very complicated issue, and in solving it, Transneft is rather a tool than a decision-maker. If the government resolves that there is a need to introduce the quality bank system – and Transneft is 100% ready for that up to now, both in methodological and program terms – then it is likely to have to adjust the tax mode for those enterprises that extract crude with high sulphur content. In this case these enterprises will not go bankrupt.

[28] http://www.transneft.ru/press/Default.asp?LANG=EN&ATYPE=9&PG=3&ID=647

Russia's Federal Energy Commission, which regulates oil pipeline tariffs, has suggested that an alternative system, based on discounts and premiums to pipeline tariffs, could be used to compensate producers of higher-quality crude oil. However, any system would run into opposition from Bashneft and Transneft. It seems that the government recognises the desirability of a quality bank on the Transneft pipeline system from a logical point of view, but that it has struggled to find a way of implementing such a system without creating hardship for the oil industries of Tatarstan and Bashkortostan, which have benefited from the existing system. A quality bank is only likely to be introduced on the Transneft pipeline system if some way can be found of compensating Tatneft and Bashneft.

3.3.2 Caspian Sea Region oil and gas transportation projects

At least one more major oil export pipeline from Kazakhstan may be required if the country is to realise its oil output targets for the middle of the next decade. Such a large and highly-visible project is likely to need an input from international financial institutions, just as was the case with the BTC pipeline and the Chad-Cameroon pipeline in West Africa.

For gas, the South Caucasus Gas Pipeline (SCP), running from Azerbaijan to the Georgia/Turkey border is already under construction with EBRD support. BG, joint operator if the Karachaganak gas/condensate project in northern Kazakhstan is reviewing future gas utilisation options, one of which is the construction of a gas pipeline across Kazakhstan to China to serve both domestic and export markets. This is only one of a number of gas utilisation proposals being evaluated.

Trans-Caspian transportation of oil from Kazakhstan and Turkmenistan to Azerbaijan (for onward shipment through BTC or by rail to Batumi in Georgia), Russia (for onward delivery to Novorossiysk) and Iran is expected to continue to be handled by tankers, rather than by new pipelines. The development of the Kashagan field in Kazkahstan and other projects being undertaken in the northern Caspian are expected to significantly boost oil production from the region, with most of the additional oil expected to be exported. The increased traffic volumes are likely to require additional and larger vessels and new ports to load and unload them. At present, shipping on the Caspian Sea is dominated by Azerbaijan State Caspian Shipping Company (Azerbaijan) and KazMorTransFlot (Kazakhstan). Burren Energy Shipping and Transportation (BEST), a subsidiary of Irish Burren Energy, which operates the Nebit Dag PSA in Turkmenistan, manages a fleet of 8 tankers chartered from the Russian shipping company Volgotanker under a 15 year bare-boat charter agreement. Iran's National Oil Fleet Company has ordered six new tankers to handle traffic into the Iranian port of Neka. Other new players may emerge as the volume of traffic increases. The Bank could perhaps have a role to play in the development of this sector, both encouraging competition and ensuring that new vessels are built to the highest international standards, although this may fall outside the Natural Resources remit.

Kazakhstan intends to expand the existing port facilities at Aktau and is considering the construction of a new oil-handling port at Kuryk, located 76 km south of Aktau to handle oil exports from the offshore Kashagan field. This project will require the construction of oil and gas pipelines and oil storage facilities, as well as the building of the port itself. Kuryk is a small town, with a population of just 4,800, so the project would have a major impact on the area.

The Caspian Pipeline Consortium set up a quality bank to preserve the value of individual crude oil streams put into the pipeline when the line was first constructed. A similar system for the BTC pipeline will be required if or when the line begins to carry oil from projects other than ACG. In the CPC case, the quality bank was originally set up as an offshore settlement system, but legislation changes in Kazakhstan allowed the consortium to establish a domestic settlement system in Kazakhstan, which came into effect in mid-2003. The Bank could possibly have a role in supporting the creation of a similar domestic settlement system in Azerbaijan for a BTC quality bank.

3.3.3 Oil and gas transportation projects in Central and Eastern Europe

The Bank is in a position to use its considerable experience in the funding of cross-border oil and gas pipeline projects, built up during its involvement with the BTC and South Caucasus Gas Pipeline projects, in Central and Eastern Europe if any of the oil or gas pipelines planned for the region move ahead towards construction. The various Bosphorus bypass pipelines, including Burgas-Alexandroupolis, Burgas-Vlore and Constanta-Trieste, would all benefit from the Bank's involvement. The Bank's presence would help to ensure that the projects are carried out to the highest environmental standards and would serve the Bank's objectives of additionality and increasing competition. The planned Nabucco gas pipeline offers the Bank a similar opportunity in the gas sector.

3.4 OIL REFINING PROJECTS

The Bank's involvement in the Fergana refinery project in Uzbekistan points the way to further opportunities in the oil refining sector. There is still much work to be done in the Bank's countries of operation to upgrade refineries in several ways. Firstly, the depth of refining (the proportion of light, high-value products produced) remains well below that of Western refineries in all but the most efficient of plants. Secondly, products produced often fail to meet more stringent quality requirements of export markets, limiting the scope for overseas sales. Both of these problems can be solved with investment in upgrading capacity to further crack heavy products into lighter ones and to remove sulphur and other impurities from products produced.

3.5 POLICY DIALOGUE

In addition to its financing role, the EBRD has continued to have an important input into policy dialogue with the governments of its countries of operation. Although significant steps have been taken by some of these governments, there remain many issues on which further progress needs to be made. Several of these have been discussed elsewhere in this paper, but it is perhaps useful to bring them together in a single section.

The creation of successful, competitive oil and gas industries requires further improvements to the business environment in many of the Bank's countries of operation. In particular, private investors – whether foreign or domestic – need to be confident that their activities will be subject to a clear and relatively stable set of rules and regulations, which will be administered without discrimination by an impartial authority. Too often privately-owned oil and gas interests seem to have been subject to the depredations of individuals with political leverage and government officials. In May 2002, Hurricane Hydrocarbons (since re-named PetroKazakhstan) was forced to cut its output by more than 50% due to newly-imposed export restrictions that followed the resignation of Kazakhstan's Prime Minister and several cabinet ministers. Company spokesman Ihor

Wasylkiw was quoted by Canada's Financial Post at the time as saying 'Understandings that were in place [with the old government] went out the door. We had to start fresh establishing new relationships with new people.'[29] More recently, the company has again been forced to cut output to comply with gas flaring regulations. While this latest cut appears on the face of it to be reasonable in the light of government legislation on gas flaring, there is no evidence that other oil producers in Kazakhstan have been served with similar instructions. On its website, PetroKazakhstan points out that just five of the 34 oil producers in Kazakhstan operate without gas flaring. It further points out that its operations at Kumkol flared 26.3 mn m^3 of gas in 1Q05, less than 4.5% of the total volume of 604 mn m^3 of gas flared in Kazakhstan over the same period.

Too often, it appears access to state-owned oil and gas export infrastructure (generally pipelines, but also rail facilities) is used to discriminate against particular companies, or against neighbouring countries. There is much work still to be done to improve the regulation of and access to oil and gas transportation infrastructure. Allocation of space in oil and gas pipelines should ideally be undertaken by an independent authority on a transparent, non-discriminatory basis. This seems to be a particular problem in Russia and, from time to time, in Kazakhstan.

In Russia the recent Yukos affair has raised serious concerns about the rule of law in business situations and the influence of government officials. Although the Russian government maintains that the actions taken against Yukos and its former CEO Mikhail Khodorkovsky were related simply to illegal activities undertaken by the company and its CEO, there remains a belief in business circles, both inside and outside Russia, that the action was undertaken in retribution for Mr Khordokovsky's political ambitions. Whatever the motivation, the action appears to have been designed from an early stage to force the break-up of Yukos and the re-distribution of its assets. The imposition of huge tax demands and simultaneous freezing of the company's bank accounts left the company with no way to pay either the government, or its running costs, leading inevitably to the forced sale of assets. The seizure and subsequent sale of Yukos's core upstream asset (Yuganskneftegaz) to a state-owned company for a fraction of its unencumbered value raised serious questions about the rule of law in Russia and has had a huge negative impact on investors, both foreign and domestic.

Russia has recently signalled that foreign oil companies will not be permitted to bid for licences to develop certain 'strategic' oil, gas and mineral deposits. While this clearly goes against the principle of an open and competitive hydrocarbons sector with equal opportunities for all potential investors, the exclusion of foreign companies is not unique to Russia. Saudi Arabia and Kuwait do not presently permit foreign investment in upstream oil projects, although a process is underway in Kuwait to open parts of the country to foreign investment. In Iran, foreign investment in upstream oil projects is only permitted under 'buy-back' contracts, which do not give foreign companies ownership of oil. In Venezuela, the government has recently decided that all oil projects must be re-negotiated to bring them into line with new legislation requiring that state-owned Petroleos de Venezuela be the major partner in all such projects.

The oil and gas sector generally would benefit from greater transparency. The Bank should continue to endorse the principles of the Extractive Industries Transparency Initiative, with

[29] 'Kazakh problems swipe Hurricane', Financial Post (of Canada), 28 May 2002.

a view to eventual endorsement of that initiative by the governments of Russia and Kazakhstan. Transparency is an issue for the industry at every level of its interface with government, from the central authorities in Moscow, Baku or Astana, to the local governments in specific areas of operation. It is frequently argued by investors in Russia that too many ministries, committees and authorities, often with overlapping jurisdictions and unclear boundaries, are involved in the issuing of permits and the policing of operations. The overlap and the lack of clarity is an open invitation for confusion and, at worst, corruption.

Energy policy is still evolving in the EBRD's countries of operation and the Bank is perhaps in a position to influence this evolution to some degree. Production sharing agreements signed in the mid-1990s in both Russia and Kazakhstan are now widely regarded as having been too generous to the foreign investor at the expense of the host country and the concept of using PSAs as a contractual model is being re-evaluated. It looks likely that the PSA may well remain as the contract type of choice for large, capital-intensive offshore projects in both Russia and Kazakhstan, but in a form that is likely to be much more favourable to the host government. Although the terms of such contracts form part of the negotiation between investors and host governments, the Bank is possibly in a position to influence the host governments in their choice of PSAs as the contractual vehicle of choice for such projects.

The European Union's energy sector policy with regard to the Bank's countries of operation is broadly in line with the aims of the Bank, in that co-operation between the EU and the transition countries takes place within the principles of a market economy and seeks closer integration among energy markets in Europe. The EU has signed Partnership and Co-operation Agreements with Russia, Azerbaijan, Armenia, Georgia, Kazakhstan, Kyrgyzstan, Moldova, Ukraine and Uzbekistan. The agreements are broadly similar in every case, setting out areas of co-operation that include security of energy supply, energy policy formulation, management and regulation of the energy sector, promotion of energy saving and energy efficiency.

AGREEMENT ON PARTNERSHIP AND COOPERATION BETWEEN THE EUROPEAN UNION AND THE RUSSIAN FEDERATION[30]

Article 65
Energy

1. Cooperation shall take place within the principles of the market economy and the European Energy Charter, against a background of the progressive integration of the energy markets in Europe.

2. The cooperation shall include among others the following areas:

a. improvement of the quality and security of energy supply, in an economic and environmentally sound manner;

b. formulation of energy policy;

– improvement in management and regulation of the energy sector in line with a market economy;

c. the introduction of the range of institutional, legal, fiscal and other conditions necessary to encourage increased energy trade and investment;

d. promotion of energy saving and energy efficiency;

e. modernization of energy infrastructure including interconnection of gas supply and electricity networks;

– the environmental impact of energy production, supply and consumption, in order to prevent or minimise the environmental damage resulting from these activities;

f. improvement of energy technologies in supply and end use across the range of energy types;

– management and technical training in the energy sector.

AGREEMENT ON PARTNERSHIP AND COOPERATION BETWEEN THE EUROPEAN UNION AND THE REPUBLIC OF ARMENIA[31]

Article 54
Energy

1. Cooperation shall take place within the principles of the market economy and the European Energy Charter and bearing in mind the Energy Charter Treaty and the Protocol on Energy Efficiency and Related Environmental Aspects, against a background of the progressive integration of the energy markets in Europe.

2. The cooperation shall include among others the following areas:

g. formulation and development of energy policy,

h. improvement in management and regulation of the energy sector in line with a market economy,

[30] http://europa.eu.int/comm/external_relations/ceeca/pca/pca_russia.pdf
[31] http://europa.eu.int/comm/external_relations/ceeca/pca/pca_armenia.pdf

- improvement of energy supply, including security of supply, in an economic and environmentally sound manner,

i. promotion of energy saving and energy efficiency and implementation of the Energy Charter Protocol on Energy Efficiency and related environmental aspects,

- modernization of energy infrastructures,

j. improvement of energy technologies in supply and end use across the range of energy types,

- management and technical training in the energy sector,

k. transportation and transit of energy materials and products,

- the introduction of the range of institutional, legal, fiscal and other conditions necessary to encourage increased energy trade and investment,

- development of hydro-electric and other renewable energy resources.

3. The Parties shall exchange relevant information relating to investment projects in the energy sector, in particular concerning the construction and refurbishing of oil and gas pipelines or other means of transporting energy products. They shall cooperate with a view to implementing as efficaciously as possible the provisions of Title IV and of Article 47, in respect of investments in the energy sector.

The articles on energy in the agreements signed with Azerbaijan (Article 55) and Georgia (Article 56) are the same as that in the agreement with Armenia.

AGREEMENT ON PARTNERSHIP AND COOPERATION BETWEEN THE EUROPEAN UNION AND THE REPUBLIC OF KAZAKHSTAN[32]

Article 53
Energy

1. Cooperation shall take place within the principles of the market economy and the European Energy Charter, against a background of the progressive integration of the energy markets in Europe.

2. The cooperation shall include among others the following areas:

l. formulation and development of energy policy,

m. the environmental impact of energy production supply and consumption, in order to prevent or minimize the environmental damage resulting from these activities;

n. improvement of the quality and security of energy supply, including diversification of supply, in an economic and environmentally sound manner;

o. formulation of energy policy;

p. improvement in management and regulation of the energy sector in line with a market economy;

q. the introduction of the range of institutional, legal, fiscal and other conditions necessary to encourage increased energy trade and investment;

[32] http://europa.eu.int/comm/external_relations/ceeca/pca/pca_kazakhstan.pdf

r. promotion of energy saving and energy effectiveness;

s. modernization of energy infrastructure;

t. improvement of energy technologies in supply and end use across the range of energy types;

u. management and technical training in the energy sector;

v. security in energy supply, transportation and transit of energy and energy materials.

The articles on energy in the agreements signed with Kyrgyzstan (Art. 54), Moldova (Art. 60) and Ukraine (Art. 61) are the same as that in the agreement with Kazakhstan, except that the agreements with Moldova and Ukraine exclude the point on security in energy supply, transportation and transit of energy and energy materials.

AGREEMENT ON PARTNERSHIP AND COOPERATION BETWEEN THE EUROPEAN UNION AND THE REPUBLIC OF UZBEKISTAN[33]

Article 53
Energy

1. Cooperation shall take place within the principles of the market economy and the European Energy Charter, against a background of the progressive integration of the energy markets in Europe.

2. Cooperation shall concentrate, inter alia, upon the formulation and development of energy policy. It shall include among others the following areas:

w. management and technical training in the energy sector;

x. improvement in management and regulation of the energy sector in line with a market economy,

y. improvement of energy supply, including security of supply, in an economic and environmentally sound manner,

z. promotion of energy saving and energy efficiency and implementation of the Energy Charter Protocol on Energy Efficiency and related environmental aspects,

aa. modernization of energy infrastructures,

bb. improvement of energy technologies in supply and end use across the range of energy types,

cc. management and technical training in the energy sector,

dd. transportation and transit of energy materials and products,

ee. the introduction of the range of institutional, legal, fiscal and other conditions necessary to encourage increased energy trade and investment,

ff. development of hydro-electric and other renewable energy resources.

[33] http://europa.eu.int/comm/external_relations/ceeca/pca/pca_uzbekistan.pdf

3. The Parties shall exchange relevant information relating to investment projects in the energy sector, in particular concerning the production of energy resources and the construction and refurbishing of oil and gas pipelines or other means of transporting energy products. The Parties attach particular importance to cooperation regarding investments in the energy sector and the manner in which these are regulated. They shall cooperate with a view to implementing as efficaciously as possible the provisions of Title IV and of Article 46, in respect of investments in the energy sector.

In the EU's negotiations with Russia over the latter's accession to the WTO it became clear that the over-riding concerns for the EU are the security of energy supplies from Russia to the EU countries and the harmonisation of domestic energy prices in Russia with international prices. Other issues appear to hold a subordinate position to these concerns and one can surmise that the EU will be less willing to press for progress on these issues if there is a risk of weakening resolve in Russia to raise domestic fuel prices. This perhaps leave a number of areas in which the Bank might seek to move the policy debate forward in some of its countries of operation.

4 GLOBAL CONCERNS

4.1 ENVIRONMENTAL IMPACT

Over the five years since the Bank's Natural Resources policy was last updated global concerns about the environment and the role of fossil fuels have intensified. While certain NGOs will oppose any and all fossil fuel projects, fossil fuels have a vital role to play in the development of the economies of many transition countries. The environmental impact of natural resources projects was not a major concern in these countries before the 1990s and there is tremendous local environmental degradation associated with such projects, particularly in the vicinity of oil extraction and transportation projects. In addition to local environmental degradation, issues of greenhouse gas emission through gas flaring and/or venting, leakage from pipelines and the inefficient use of energy have traditionally been low on the list of priorities for energy projects in the transition economies.

4.1.1 Local environmental impact

The local environmental damage caused by oil extraction and transportation in the countries of the former Soviet Union is almost legendary, whether it is the oil lake that resulted from the rupturing of an oil pipeline in the Komi Republic or the network of leaking pipes and wellhead facilities that fill the view across the waterfront in central Baku. Governments are beginning to take protection of the local environment around oil installations more seriously, but this can cause problems for oil companies contemplating projects to rehabilitate existing fields. For instance, Lukoil recently announced that it was withdrawing from the Govsany-Zykh oilfield project in Azerbaijan because the cost of environmental remediation in the heavily polluted territory around the field (one third of the total $300 mn investment) made the project unprofitable.

Environmental remediation of the territory around old oilfield developments is clearly desirable. However, such a requirement can fundamentally undermine the profitability of a project, especially where the incremental oil production may be quite limited. Rather than placing the burden for rectification of past neglect on new owners, perhaps the Bank might use its position to lobby for the creation of a fund to support such remediation work, to which companies rehabilitating old oilfields would have access for environmental remediation.

In his recently published book, 'Collapse – how societies choose to fail or survive', Jared Diamond contrasts his own first-hand experience of two oilfield development projects in the New Guinea region. Visiting a state-owned oil companies operation, funded internally with no outside involvement he found rampant gas flaring, 100-yard-wide swathes cut through the rainforest to provide access to the site and pools of spilled oil. At a second site, the Kutubu field operated by a subsidiary of Chevron at the time of his visit, which was developed with funding from the World Bank, the picture was very different. Diamond found access roads just wide enough for two vehicles to pass safely (narrow enough not to create a barrier to wildlife) and an extreme concern for the operation's impact on the local environment. The World Wildlife Fund (as it was then called) had been employed had been employed to prepare a large-scale integrated conservation and development project for the Kikori River watershed where the project was located. During the course of his visits on behalf of the WWF, Diamond found to his surprise that several species of bird and mammal whose presence and abundance are sensitive indicators of human disturbance were more numerous inside the oil company's area of operation than they were outside.[34] The above example illustrates the dramatic impact that external scrutiny can have on the local impact of upstream oil and gas projects in sensitive areas and, I believe, is a strong argument for the continued involvement of IFIs in such projects.

The Bank should continue to demand the highest environmental standards from the upstream and transportation projects it is involved in. Monitoring of these projects should be ongoing, with companies' performance compared with clear and measurable benchmarks and sanctions applied to companies that fail to fulfil their obligations.

4.1.2 Gas flaring/venting

When oil is produced, it often comes to the surface in combination with dissolved natural gas (associated gas). The oil and gas are generally separated at the wellhead (along with any water that also comes to the surface). Where possible, the associated gas is either sold or utilised on site, either to supply on-site fuel needs or for power generation, or for re-injection into the oil reservoir to maintain pressure and production rates. In locations remote from gas transportation infrastructure and where there is no requirement for gas re-injection for pressure maintenance, gas may be released into the atmosphere, either ignited (flared) or unignited (vented). The World Bank Group (WBG) has estimated that the annual volume of natural gas being flared and vented around the world is about 100 billion cubic meters (bcm), enough fuel to provide the combined annual gas consumption of Germany and France.

Vented gas is much more potent as a greenhouse gas (GHG) than flared gas. The combustion of the gas converts the emission into one that is predominantly in the form of carbon dioxide (CO_2) rather than methane (CH_4), the latter being 27 times more potent than the former in its greenhouse effect. If it is impossible in practical terms to avoid the emission of gas into the atmosphere, it remains imperative that this gas is fully combusted prior to emission, ensuring that the emissions are in the form of CO_2, rather than CH_4.

In 2001, the Global Initiative on Natural Gas Flaring Reduction (GGFR)[35] was initiated by the government of Norway and the World Bank Group (WBG) to investigate the issue. It found that for the past 20 years, global flaring levels had remained virtually constant (although individual country levels have fluctuated), despite efforts made by individual governments and companies, and despite many successes in reducing flaring. The overall effect of these reduction efforts has been limited because of (1) the increase in global oil production and gas production over the period; and (2) major constraints hindering viable flare reduction projects, which require a collaborative approach with key stakeholders taking complementary and supportive actions.

The aim of GGFR is to support national governments and the petroleum industry in their efforts to reduce flaring and venting of gas associated with the extraction of crude oil. The steering committee approved a three-year work program beginning in January 2003, coordinated by a small team based at the World Bank. The work program focuses on four areas of activity to reduce gas flaring and venting in partner countries:

(1) commercialisation of associated gas;

[34] Diamond (2005), pp442-446.
[35] Further information on the GGFR can be found at http://www2.ifc.org/ogmc/global_gas.htm

(2) regulations for associated gas;
(3) establishing a flaring and venting reduction standard; and
(4) capacity building related to carbon credits for flaring and venting reduction projects.

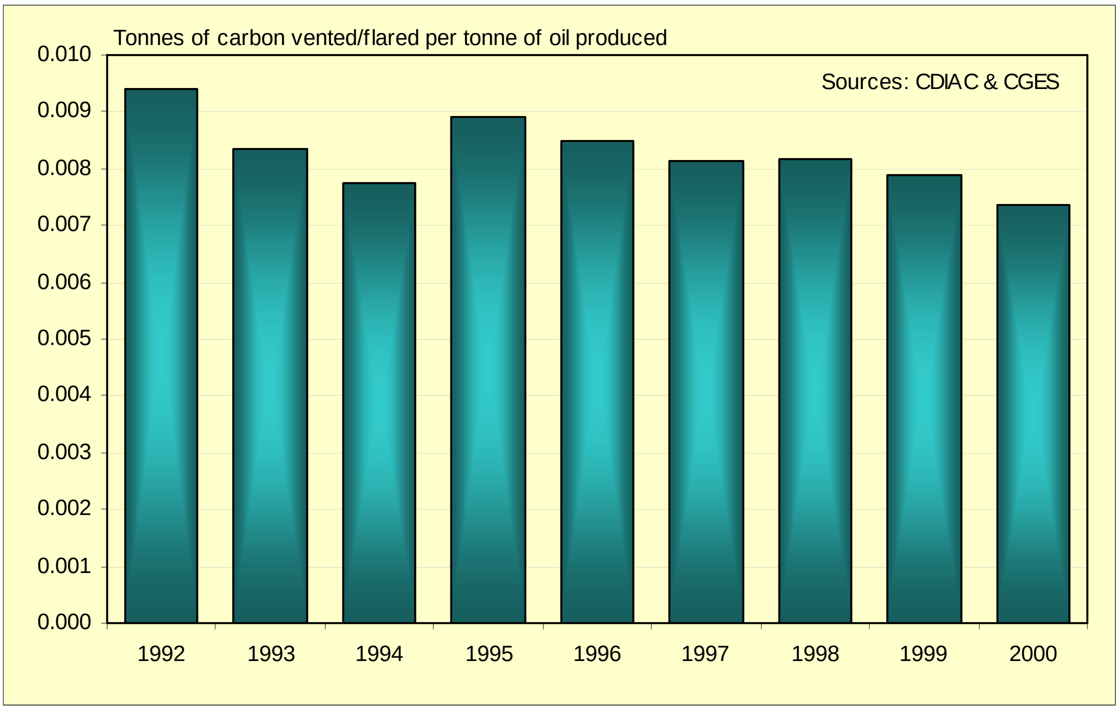
Supporting activities include data gathering, consultations, and identification and dissemination of best practice.

The World Bank's Global Gas Flaring Reduction Partnership (GGFR) was launched at the World Summit on Sustainable Development (WSSD) in August 2002. In addition to the World Bank, this public-private partnership currently comprises BP, ChevronTexaco, ENI, ExxonMobil, Norsk Hydro, Statoil, Shell, Sonatrach and Total and the governments of Angola, Cameroon, Canada, Chad, Ecuador, Equatorial Guinea, Indonesia, Nigeria, Norway, and the United States. It is noticeable that none of the transition countries has joined the partnership.

Gas flaring and/or venting is generally a problem in areas that are remote from gas transportation infrastructure, or where access to such infrastructure is not available. This is certainly the case in Russia, where access to Gazprom's pipeline network is not guaranteed for third-party producers and where future oilfield exploration and development is expected to take place in increasingly remote areas like Eastern Siberia. In 1998, the most recent year for which cross-country comparisons are available, data show the Russian Federation as the world's fifth largest source of CO_2 emissions from gas flaring[36] after Nigeria, Iran, Algeria and the United States of America, accounting for XX% of total global CO_2 emissions resulting from gas flaring. Russia's CO_2 emissions from gas flaring have remained fairly constant at a rate of 7,000-10,000 metric tons of carbon per million metric tons of oil produced.

[36] Earthtrends website.
http://earthtrends.wri.org/searchable_db/index.cfm?theme=3&variable_ID=464&action=select_countries

Figure 16: Russia's carbon emissions from gas flaring per tonne of oil produced



All of the Bank's other countries of operation show CO_2 emissions from gas flaring as zero, but these data must be treated with a high degree of caution. The total CO_2 emissions from gas flaring for the USSR in 1991 are reported by the Carbon Dioxide Information Analysis Center (CDIAC) at the Oak Ridge National Laboratory in the US at 6,297.6 thousand metric tons of carbon. In 1992, the first year in which the individual countries emissions were reported separately, this figure fell to just 2,874.8 thousand metric tons (2,354.5 thousand metric tons for Russia and 520.3 thousand metric tons for Azerbaijan), yet there is no obvious reason for this more than halving of CO_2 emissions from gas flaring. We suspect that gas venting/flaring in FSU republics other than Russia is not being fully reported, either as a result of simple omission, or because the gas is vented in the form of CH_4 rather than being flared. Azerbaijan certainly continued to vent natural gas from the Neft Dashlari and Guneshli fields at least until the installation of gas compression facilities by Pennzoil in July 1994[37], yet CDIAC reports the country's emissions from as flaring as zero from 1993 onwards.

We would recommend that the EBRD join the GGFR initiative, encouraging the governments of its countries of operation to sign up to the agreement and requiring sponsors of the projects in which it invests to do the same. Such a move would demonstrate the Bank's commitment to help tackling the problem of gas venting/flaring. In projects where gas emissions to the atmosphere are unavoidable, the Bank should make it a requirement of its involvement that gas is fully combusted prior to emission, making on-going monitoring of gas flaring a condition of its involvement.

[37] Dunn, D.W. & Isenhower, D.B., 'Azerbaijan Begins Major Project that Affects Global Warming', in Azerbaijan International, Summer 2004.

4.1.3 Gas losses from pipelines

Atmospheric pollution resulting from the leakage of gas from the pipeline network of the FSU has long been a concern, although the extent of this problem is not as great now as it may have been in the past, and far less serious than had been feared in the early 1990s.

Analyses of gas emissions from Gazprom's gas export pipeline network made by the Wuppertal Institute and the Max Planck Institute for Chemistry between 2002 and 2004[38] concluded that CH_4 emissions from the network accounted for 0.7% of the volume of gas exported, slightly down on the 1% loss assessed independently in the mid-1990s by the US Environmental Protection Agency and by E.ON Ruhrgas. The 2004 study determined a 95% confidence interval for CH_4 emissions from the export pipeline network of 0.4%-1.6% of the exported gas. The main sources of CH_4 emissions were identified as "leaks or releases from machines and valves of compressor stations for technical reasons and – to a lesser extent – due to leaks on pipeline valves."[39] Gas venting for maintenance purposes or repair and gas losses as a result of pipeline failure were identified as being of only minor importance.

The 2004 study also noted that CH_4 emissions from pipelines were only one source of GHG emissions and calculated that these, in fact, accounted for around one third of total emissions. The remaining two thirds of GHG emissions were in the form of CO_2, resulting from the burning of gas to power the turbines used for transmission and provide the electric power required for driving motors. The level of these emissions is determined in part by the distance over which the gas is moved (between 4,300 km and 5,500 km from West Siberia to the German border) and the efficiency of the turbines installed. Average turbine efficiency has improved as older units have been replaced and this is expected to continue as Gazprom continues to maintain its gas export network.

4.2 SOCIAL IMPACT

Future oil and gas projects, particularly in Russia, are expected to be undertaken in increasingly remote areas of the country such as East Siberia and Kamchatka, where large industrial projects have not been seen before and are likely to have a major impact on local populations and wildlife. Such projects need to be sensitively managed. In the face of the determination of the Russian government to open such areas to oil and gas exploration and development, it is unrealistic to expect that refusal by the Bank to support such projects would lead to them being abandoned. It is therefore vital that the Bank play a role where it can in frontier projects, using its expertise and position to ensure that the local impact on populations and wildlife is as benign as possible, that projects are continually monitored and that sanctions are imposed on projects that fail to meet their obligations to local people and local wildlife.

[38] 'Greenhouse Gas Emissions of Russian Natural Gas Export Pipelines – Summary Report', Wuppertal Institute and Max Planck Institute for Chemistry, December 2004. The full report is available in German and is due to be published in English in January 2005. The report can be accessed via the Wuppertal Institute's website at www.wupperinst.org

[39] Ibid.

The procedures suggested by Professor Auty[40] to maximise the positive regional effects of mining projects are equally applicable to oil and gas extraction/transportation projects. These include:

- conducting a broader economic analysis of proposed projects, rather than just a financial analysis of a project's profitability;
- espousing environmental accounting;
- screening corporate social responsibility by commissioning social audits;
- strengthening incentives for effective governance; and
- ring-fencing linked investments against predatory governments.

An economic analysis of proposed projects can 'check [a project's] likely social sustainability in the light of its projected welfare benefits [and can be used] to provide a blueprint against which to compare the actual delivery of the socio-economic benefits … with the projected outcome, and to determine the reasons for any departures from the projected outcome. Moreover, an economic analysis can also be used to identify scope for linked activity and to determine effective ways of promoting it. Finally, an economic analysis facilitates the assessment of the opportunity cost of a project compared with alternative uses of the land and labour, including differences in the likely distribution of benefits between the various regional and income groups.[41]'

Auty rightly asserts that 'environmental damage created by the extractive industries should be internalized on a current basis, even in cases where the effects of damage are long delayed,' and that 'the environmental costs should be borne by the mining firms that create the damage rather than being absorbed by government or borne by members of society who are victims of pollution and other natural asset degradation.'[42] These principles can create difficulties for projects targeting the rehabilitation of brownfield sites, where existing environmental degradation has often been caused by the operations of state-run oil production associations. An environmental audit can provide a baseline assessment of pre-existing environmental damage and form part of the agreement as to what is the responsibility of the investor in terms of environmental remediation. The author agrees with Auty that 'efficient limitation of environmental damage requires informed control by government agencies in setting and enforcing environmental standards. In general, the use of economic incentives, such as fees, on the emission of pollutants is more efficient than command and control measures such as fixed emission requirements or demands to use specific technologies.'[43]

While corporations are increasingly aware that they have responsibilities to the communities in which they operate, it is important also to recognise that there are limits to these responsibilities. Responsibility towards local communities affected by extractive industries ought to encompass not just the provision of compensation but also help the community to benefit from the opportunities created by the project without becoming dependent upon it. This is particularly true of projects that may provide a short period of labour-intensive construction, followed by a long period of operation requiring very few employees, followed by de-commissioning and abandonment. The creation of funds to encourage skills creation and business diversification has proved successful in several instances quoted by Auty. However, care needs to be exercised that such programmes do not lead to national and local

[40] Auty (2005) pp24-34.
[41] Ibid, p25
[42] Ibid, p26-27
[43] Ibid, p27

governments abrogating their responsibilities in the regions where such funds exist. An external and ongoing ‘social audit’ of projects is suggested by Auty as a useful means of ensuring that companies meet, but do not exceed their obligations to the communities affected by their projects.

Host governments, both national and local, have a role to play in monitoring the economic, social and environmental obligations of companies operating on their territory, but are often ill equipped to do so. The IFIs, among them the EBRD, can assist through carrying out their own monitoring in the early stages while both encouraging and assisting governments to build up their own capabilities to monitor projects in a transparent and equitable fashion. Environmental and social audits can and have been misused to put pressure on or extract payments from companies that have been in compliance with, perhaps poorly drafted, requirements. Such misuse can be particularly effective once a project is becoming profitable after large capital investments have been made.

4.2.1 Impact on indigenous peoples and wildlife habitats

Wide-ranging environmental and social impact assessments should be a pre-requisite for oil and gas projects in frontier areas. Indeed, such assessments have served to highlight conflicts between oil and gas projects and the populations and wildlife of the proposed areas of operation. Recent examples include the impact on the population of Grey Whales of offshore pipelines at the Sakhalin 2 project, the re-routing of the proposed East Siberian oil export pipeline (the Taishet-Nakhodka pipeline) to avoid a natural park to the south of Lake Baikal and the questions being raised over the location of the proposed oil export terminal for the Taishet-Nakhodka pipeline project – the favoured location of Perevoznaya raising concerns over the impact on the local leopard population.

While local impact needs to be treated as a serious issue, it is one that can be, and has been, manipulated by opponents of projects, or particular aspects of projects, to serve their own ends. For example, it has been suggested that the impact on the leopard population of the proposed Perevoznaya oil export terminal has been inflated by the local authority to force Transneft to locate its export terminal at Nakhodka, where the authority has a tight grip on operations[44].

4.2.2 Provision of local benefits

The extent to which projects are expected to bring benefits to local communities in the regions in which they are located is a vexed issue across the globe and one that is highly charged emotionally. It is tempting to see ‘rich’ corporations (often foreign) as providers of much-needed development assistance to local communities in the regions in which they operate. The most high-profile recent examples of this are the Baku-Tbilisi-Ceyhan (BTC) pipeline and the South Caucasus Gas Pipeline (SCP). The former is intended to carry 1 mbpd of crude oil from Azerbaijan via Georgia for export from a terminal in Turkey, passing en route villages in all three countries that have no electricity, while he latter will carry natural gas along the same route into north eastern Turkey. It has been suggested that the pipeline consortia, responsible for moving so much energy in the form of oil and gas, should be responsible for the provision of energy in the form of electricity to these communities, who would otherwise be jealous of the energy wealth passing their doorsteps. Not only is there no good reason for this (beyond simple charity), but such a move would also set a dangerous precedent. The provision of power, or any other service,

[44] ‘Transneft aims for mid-year construction start’, FSU Energy, 4 March 2005, p3

to its population is the business of government, either directly or through creation of the regulatory environment in which private companies will seek to do so. The provision of basic services by private companies (often foreign) operating in one region of a country to people who happen to live in that part of the country runs the risk of undermining the authority of government and creating internal division. The foreign company comes to be seen as the provider of basic necessities, while government is perceived as a remote entity that raises taxes but provides little or nothing in return.

Taking the BTC and SCP pipelines as an example, a number of issues are raised by suggestions that the consortia developing the pipelines should provide power to local populations. Firstly, how local is 'local'? Should the provision be made just to those villages directly on the pipeline's route, to those within a fixed distance of the pipeline route, or to those within the administrative districts through which the line passes? What about those just beyond the cut-off point? The provision of power doesn't end the energy jealousy; it merely shifts it away from the route of the line itself. Secondly, why should a pipeline consortium become a power utility? The consortia will not own the oil or gas they transport any more than a haulage company owns the contents of its lorries, or a shipping company the cargoes carried on its vessels. A fee is paid to the governments of the transit countries for every barrel of oil or cubic metre of gas that moves through the pipeline (indeed, part of the tariff paid to Georgia for transporting gas is paid in kind). If the government wishes to provide power to the communities close to the pipeline route part of the transit fee could be used for that purpose. Thirdly, where should the charitable provision end? Why should the consortium provide electricity but not drinking water, or sewage removal, or any other basic services? The proper role of the BTC consortium is to build its pipeline to the highest environmental standards, paying proper compensation to people disrupted by the work, move oil through that pipeline safely and efficiently without spillage, and pay its taxes and transit fees to the governments of the countries through which the line passes. It is the duty of the host governments to decide how those revenues are used.

This said, corporations do have a responsibility to the communities within which they operate (see 3.2 above) and these responsibilities need to be clearly defined (and delimited) and addressed. Auty suggests the creation of Early Reform Zones (ERZs)[45] as one way to help build up dynamic markets sectors in designated geographical areas, which could be those surrounding projects funded by the Bank. The concept of these zones is discussed in some detail by Auty and will not be repeated here.

4.2.3 Major oil and gas investments as catalysts for associated projects

Linked with the provision of local benefits is the issue of how the Bank can use the big oil and gas projects it finances as catalysts for associated projects. While the Bank clearly has an important role to play in ensuring that the companies it supports are 'model citizens' in their dealings with local populations and the environment, it also has the opportunity to use the projects it supports to develop local industries and infrastructure.

I am not sure that I am able to add anything to the results of the work being undertaken with Richard Auty, since this is really not my field of expertise. However, I can say that big oil and gas projects tend to go through a labour-intensive development phase (which typically includes the construction of surface facilities and pipelines as well as the drilling

[45] Ibid, p32

of wells and fabrication and installation of offshore structures where appropriate) followed by a long production phase requiring the employment of far fewer people. For example, the BTC pipeline website has the following to say about manpower requirements[46]:

> "Construction of the BTC pipeline will provide work for some 10,000 people during construction in the host nations [which is expected to last 14 months] - many of whom will be recruited and trained locally. Almost 1,000 long-term positions will be needed to manage and maintain the system for its 40 years of operation."

While some of the investment in any oil and gas project will undoubtedly take place far from the site of the project, with some equipment inevitably fabricated outside the country of operation, local content requirements almost invariably mean that much of the work will be carried out in country by local workers. The relatively short-term nature of the development phase of big oil and gas projects means that a large number of short-term jobs are created, leading to an influx of workers into the project area and a build up of both skills and expectations. With its broader mandate than merely supporting oil and gas projects, the Bank is, perhaps, in a unique position to actively support associated projects around the large oil and gas ventures it supports, drawing on the manpower and skills that are created in or brought into the region. Although I have no formal expertise in this area, my previous experience in the Zambian copper industry suggests that a healthy private sector of small/medium-sized enterprises can successfully be created around large industrial projects, providing support to those enterprises and services to their employees.

4.3 GLOBAL CLIMATE CHANGE

Global climate change has moved rapidly up the political agenda in the five years since the Bank last reviewed its Natural Resources Policy. The Kyoto Protocol came into force in February 2005 following its ratification by the Russian parliament and the major international oil companies have all embraced, to some degree or another, the ideas of anthropogenic climate change and the need to develop alternatives to fossil fuels. Fossil fuels projects face much greater scrutiny, and much greater hostility, than they did even five years ago. The Extractive Industries Review[47] carried out and published by the World Bank in 2003 proposed that 'the WBG should phase out investments in oil production by 2008 and devote its scarce resources to investments in renewable energy resource development, emissions-reducing projects, clean energy technology, energy efficiency and conservation, and other efforts that delink energy use from greenhouse gas emissions. During this phasing out period, WBG investments in oil should be exceptional, limited only to poor countries with few alternatives.'[48] The WBG's management backed away from any such commitment, stating in their final response to the Extractive Industries Review that, 'by staying engaged in oil and coal we [the WBG] can have an influential role in ensuring that the best environmental and social practices are followed and that the goal of sustainable poverty reduction is achieved.'[49]

It is clear to the author that the IFIs must continue to be involved in upstream oil (and gas) projects in their countries of operation. Not only are such projects vital to the economies of those countries, properly managed they can also contribute to the aims of the institutions

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[46] http://www.caspiandevelopmentandexport.com/ASP/BTC_LastingBenefit.asp
[47] World Bank (2003)
[48] Ibid, Executive summary, p7.
[49] World Bank (2004), Executive summary, p7.

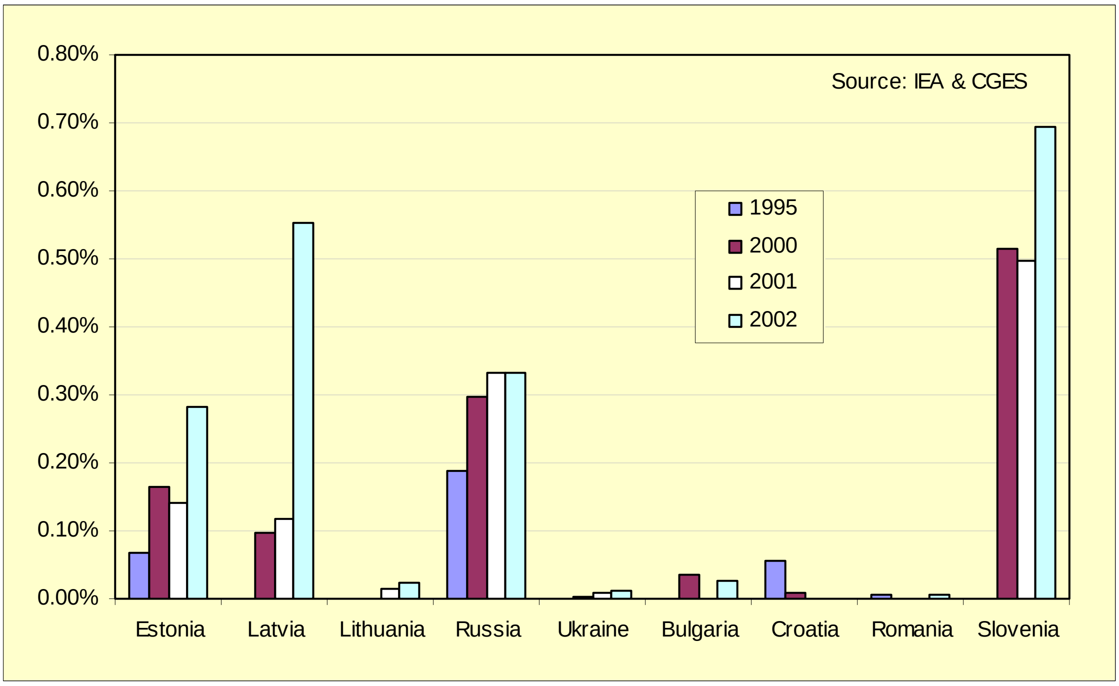
themselves. A more difficult question is to what extent the Bank ought to embrace renewable energy projects and whether it ought to set binding targets for itself in supporting such projects. There are several difficulties with such a policy and few benefits, beyond appeasing the environmental lobby.

Firstly, there is a question of definition. Not all forms of renewable energy are seen as benign, with large-scale hydro-electric projects opposed due to their potential for displacing large numbers of people. However it is precisely in the area of large-scale hydro-electric projects that the Bank is most likely to be asked to invest in renewable energy. The development of other forms of renewable energy in the Bank's countries of operation remains in its infancy. According to data published by the International Energy Agency (IEA)[50], just nine of the Bank's countries of operation had measurable electricity production from renewable sources (excluding hydro) in 2002. In five of these nine countries, the only renewable contribution to electricity generation came from combustible renewables and waste. Only Estonia (1 GWh), Latvia (11 GWh), Russia (6 GWh) and Ukraine (22 GWh) had any solar, wind, tidal or wave generation, while Russia (156 GWh) also had some geothermal power generation. In each of the nine countries, total renewable power generation accounted for less than three-quarters of one percent of total electricity generation and in only two (Latvia and Slovenia) was it above one half of one percent.

During a presentation in May 2003 to a conference on renewable energy in the Caspian Sea region, organised by Reading University's Centre for Euro-Asian Studies, the author noted that little had been done to promote the use of renewable energy sources in republics of Central Asia and the Caucasus. Kazakhstan was the only Caspian Sea region country in which renewable energy featured in the country assistance plans of the Asian Development Bank, the plan stating that, 'renewable energy needs to be developed for the remote communities that will unlikely get grid connected electricity in the near term. Without power supply, these communities will be unable to obtain proper heating during the harsh winter, with the poor likely to suffer the most.'[51]

[50] IEA (2004)
[51] Asian Development Bank (2003)

Figure 17: The contribution of renewable energy sources to power generation in the Bank's countries of operation



Includes geothermal, solar, wind, tidal, wave, combustible renewables and waste. Excludes hydro.

Kazakhstan was also the only country in the Caspian Sea region for which a section on energy featured in the United Nations Environment Programme/Environment and Natural Resources Information Network (UNEP/ERIN) State of the Environment Report. The report made the following comments on the potential for renewable energy in Kazakhstan:

- Potential of non-traditional renewable sources of energy in Kazakhstan is quite significant, but is used to small extent due to expensive costs.
- Development of renewable energy resources would be especially efficient for power production at the local level as well as for small scattered loads.
- Small hydropower stations with capacity less than 10 MW are of great importance. … there are at least 453 potential sites.
- Good capacities exist for the use of wind energy, especially in the region of Djungar gates and the Chilik corridor.
- Significant solar energy resources exist, which allows their use in particular in rural areas, at distant pastures.

Armenia, with no indigenous fossil fuel resources, has begun to promote renewable energy sources, although development of all but hydro-power is in its infancy. In an undated interview conducted sometime in 2003 with the ARKA News Agency,[52] Aleksandr Kocharian, Head of the Renewable Energy Department of Armenia's Energy Ministry, said that 'new HPPs will allow us to generate another 1.5 bn KWh annually'. However, two thirds of this new capacity will come from three large projects, rather than small-scale hydro projects. Nevertheless, the first small-scale HPP built in Armenia with private funding was completed in 1996, according to Kocharian, who went on to say that 16 new

[52] Excusive interview with Aleksandr Kocharian, Head of Renewable Energy Department, RA Energy Ministry, to ARKA News Agency. http://www.arka.am/en/int/int19.htm

small HPPs, with capacities between 350 KW and 1 MW had been constructed since 1998-99, yielding a combined generating capacity of 12-15 MW. At the time of the interview, 4-5 new power plants were under construction.

The EBRD is establishing the *Armenia Renewable Energy Fund* capitalised by a combination of blended funding from the International Development Agency and the Global Environment Facility as well as other donor funds. Elsewhere, the Bank provided a sovereign loan of USD99.9 mn to the Russian Federation, which is being used to meet nearly two thirds of the construction cost of the Mutnovsky geothermal power plant in southern Kamchatka in Russia's Far East.

An ongoing study commissioned by the EBRD and carried out by a team led by Black and Veitch has been assessing the renewable energy resource potential in the Bank's countries of operation.

Obstacles identified by the author in 2003 to the large-scale take-up of renewable energy projects in the Bank's countries of operations include:

- Low prices for electricity and heat;
- An abundance of cheap fossil fuels (in producing countries);
- Reliance on imported technology and equipment;
- Lack of local skills/spare parts for maintenance; and
- Inability of customers to pay market prices for power supplied.

Investments in energy efficiency and renewable energy sources have a role to play in the energy mix of the Bank's countries of operation and the Bank would clearly like to be seen to be supporting non-carbon-based energy solutions, so the issue needs to be addressed. Renewable energy solutions are perhaps most relevant in resource-poor countries that have remained dependent upon imported oil, gas and coal from their resource-rich neighbours. As noted above, control over energy supplies to resource-poor countries, or control over the routes through which such energy supplies are delivered, can be and has been used as an international policy tool. Leijonhielm and Larsson found that 'Russia has, by turning off oil or gas [supplies] on several occasions, tried to use the energy weapon against [Georgia, Ukraine, Moldova, Estonia, Latvia and Lithuania] with the aim to reach a policy goal that has varied depending on the occasion, for example to enforce concessions in ongoing negotiations.'[53] For these resource-poor countries renewable energy sources provide a means of reducing their dependence on energy imported from, or through, Russia, thereby reducing their susceptibility to use of the 'energy weapon'.

Given the paucity of renewable energy projects in the Bank's countries of operation and the relatively small size of expected projects compared to those in the oil and gas sector, it does not seem sensible for the Bank to set itself quotas for renewable energy projects, since this would probably only have the effect of severely restricting its involvement in the energy sector in its entirety.

The WBG, in the management's response to the Extractive Industries Review, undertook to 'set an initial target to increase renewable energy and energy efficiency portfolio

[53] Liejonhielm and Larsson (2004) p136

commitments by 20% annually over the next five years.'[54] While setting a target for incremental investment in renewable energy and energy efficiency projects may be a first step, it is unlikely to yield spectacular results since the starting point is so low. Perhaps large-scale fossil energy projects supported by the Bank could be required to build in a renewable energy/improved energy efficiency dimension that would go beyond the immediate confines of the project itself. Most of the major international oil and gas companies have their own renewable energy businesses and local renewable energy projects in the vicinity of large hydrocarbon projects could provide a valuable demonstration of the capabilities and advantages of such technologies. This idea clearly needs a great deal of further discussion.

The WBG also announced its readiness 'to convene or participate in a "steering group" of nations, academic and research institutions, civil society, and industry that can help frame a broader agenda on renewable energy.'[55] The Bank should consider joining the steering group initiative, working with the WBG and other institutions to develop a common policy on renewable energy.

4.4 CORRUPTION AND TRANSPARENCY

It is recognised that revenues from oil and gas projects (as well as from other foreign direct investment) should be 'an important engine for economic growth and social development in developing and transition countries. However, the lack of accountability and transparency in these revenues can exacerbate poor governance and lead to corruption, conflict and poverty.'[56] At the World Summit on Sustainable Development in Johannesburg in September 2002 the UK Prime Minister Tony Blair announced the launch of the Extractive Industries Transparency Initiative (EITI). The aim of EITI is 'to increase transparency over payments by companies to governments and government-linked entities, as well as transparency over revenues by those host country governments.'[57] To date the initiative has been endorsed by both the World Bank Group and the EBRD and two of the Bank's countries of operation (Azerbaijan and the Kyrgyz Republic) have committed to the EITI. The Bank should continue to encourage its investment partners, clients and countries of operation to adopt EITI principles. As a long-term goal the Bank might consider encouraging those countries that have not signed up to EITI to do so; however, given the Bank's other transition objectives, the author does not believe that it is feasible to make adoption of EITI by host countries a precondition of its involvement in energy projects. In those countries that have not signed up to EITI, the Bank still has a role to play in seeking improvements to contract and revenue transparency. If the Bank has concerns over these issues, they should perhaps be considered on a project-by-project basis, bearing in mind the other transition objectives that might be served by investing in a particular project.

Essentially the Bank would appear to have two choices in those countries that have not signed up to EITI; either it walks away from all projects in those countries (thereby foregoing any transition impact whatsoever), or it accepts EITI as a long-term goal and, if there are other sufficiently good reasons for investing in a particular project then the Bank becomes involved while pressing for greater transparency. On a more general level, the

[54] World Bank (2004) p6
[55] Ibid.
[56] DFID (2004) p1
[57] Ibid. p1

Bank might, perhaps continue to try to influence governments in its countries of operation in favour of signing up to EITI.

It is recognised that the concept of 'publish what you pay' has run into difficulties over commercial confidentiality, with companies citing the confidential nature of their contracts as a reason why they cannot publish details of their payments to host country governments. It is important to remember what the 'publish what you pay' concept is seeking to achieve, though; an end to the theft by individuals or groups of individuals of money paid to host governments in the form of signature bonuses, royalties and taxes. For this purpose it is sufficient that companies publish aggregate payments that are sufficiently detailed to enable the funds to be traced through the recipient's account, but need not be so detailed as to compromise the confidentiality of commercial agreements.

At present the EITI is a voluntary code to which it is hoped that companies and governments will subscribe through enlightened self-interest. The Bank should, perhaps, consider acting in concert with other IFIs in seeking to make adherence to the principles of the EITI and 'publish what you pay' compulsory for all parties to projects that it supports. This, though, would be a long-term goal, rather than an immediate requirement. Of course, transparency alone does not lead to accountability and the Bank must continue to promote accountability within the governments of the countries in which it operates. The creation of 'oil funds' in Azerbaijan and Kazakhstan is an important step forwards for both of these countries and the Bank, along with other IFIs and NGOs needs to ensure that these funds continue to be managed in a transparent and responsible way. This raises a separate, but related, issue for the Bank of how government revenues derived from the projects it supports are used. Some might argue that it is for governments to decide how to use the revenues they receive, not for IFIs to dictate to them how to spend their income. The Bank, though, has a legitimate role to play in this area, since one measure of transition must be the degree of government accountability.

In the development of oilfields in Chad and the related Chad-Cameroon pipeline project, projects supported by the World Bank, a condition of IFI support was the enactment of a Revenue Management Law, under which direct revenue (dividends and royalties) from the development of the Kome, Miandoum and Bolobo oilfields are to be placed in an offshore escrow account, with 90% of the funds used in priority sectors (including public health and social welfare, educational infrastructure, rural development [agriculture and livestock], environment and water resources), to meet the governments ongoing investment and operating costs and to be distributed to the decentralised authorities in the oil-producing region. The remaining 10% of the direct revenue is to be deposited into an account with an IFI to be managed for the benefit of future generations.[58] Although the initiative was designed to help Chad deal with the sudden influx of huge oil revenues in an attempt to avoid the country suffering the 'resource curse' that has afflicted so many of its neighbours, it has come in for criticism. Perhaps the most serious of which is that the principles of the revenue management scheme are likely to be undermined by the fact that it only covers revenues from the three fields named in the law, but is not expected to cover future oil developments that now seem likely since the Chad-Cameroon pipeline has opened up access for oil exports to world markets. Despite the criticisms, the initiative in

[58] Unofficial translation of Chad's Revenue Management Law, found at:
http://www.catholicrelief.org/get_involved/advocacy/policy_and_strategic_issues/Chad_Law.pdf

Chad illustrates that in certain instances, the IFIs can play a role in overseeing how host governments use their hydrocarbons wealth as well as in demanding transparency.

The public consultation process through which Bank-supported projects pass prior to their implementation can contribute to the overall transparency of the project and it is important that the Bank continues to be involved in projects at as early a stage as possible to ensure that such transparency is a feature of projects from their outset.

4.5 NO-GO AREAS

During the public consultations that formed part of the Natural Resources Policy review, various NGOs voiced the opinion that the Bank should not finance any oil, gas, or mining projects or activities (including technical assistance) that might affect existing World Heritage properties, current official protected areas, or critical natural habitats (as defined by the World Bank Natural Habitat Policy) or areas planned in the future to be designated by national or local officials as protected. The Bank's draft response states that its Environmental Policy, which is due to be reviewed in 2006, ensures that projects which would contravene country obligations under relevant international environmental treaties and agreements would not be financed. The Bank's Environmental Policy also ensures that projects will also be structured to meet the IFC Safeguard Policies on indigenous peoples (Sept 1991), involuntary resettlement (June 1990) and cultural property (Aug 1986).

Some might suggest that the Bank should declare the northern part of the Caspian Sea a 'no-go area' for investment in light of the extreme environmental sensitivity and important fish stocks (the north Caspian is the breeding ground for sturgeon). The Caspian Environment Programme (CEP)[59] defines the North Caspian as being the area to the north of the Mangyshlak threshold, which runs between Chechen Island (near the Terek River mouth in Russia) and Cape Tiub-Karagan (at Fort Shevchenko) in Kazakhstan. While the North Caspian accounts for 25% of the surface area of the Caspian Sea, it holds just 0.5% of the sea's water volume due to its very shallow depth, which averages less than 5 metres.

[59] www.caspianenvironment.org

Figure 9: Bathymetry of the North Caspian

The CEP identified six existing major environmental problems in the Caspian Sea

Overall decline in environmental quality;
Decline in certain commercial fish stocks, including sturgeon;
Degradation of coastal landscapes and damage to coastal habitats;
Threats to biodiversity;
Decline in human health; and
Damage to coastal infrastructure and amenities (due to rising se level)

and two further emerging problems:

Introduced species and
Contamination from offshore oil and gas activities.

The CEP was established on the basis of intergovernmental agreements between the Caspian littoral countries and also receives support from the following international organisations:

The Global Environment Facility;
The United Nations Development Programme;
The EU's Tacis Programme;
The United Nations Environment Programme;
The World Bank; and

The United Nations Office for Project Services (UNOPS).

Other specific 'no-go' areas are more difficult to identify. Much of the future development of the Russian oil industry is likely to take place in environmentally sensitive areas, such as the far north and East Siberia, but it is unlikely that either of these areas would be considered 'no-go' zones.

5 CONCLUSIONS

Although the oil and gas industry environment, both globally and in the EBRD's countries of operation has changed significantly since the Bank's Natural Resources Policy was last updated in 1999, the Bank still has a vital role to play in the oil and gas sectors of the transition countries.

Rising international concern over the environmental impact of oil and gas consumption, particularly over greenhouse gas emissions, has raised the level of external scrutiny of projects in the sector. Although some groups will oppose the Bank's involvement in any project in the sector, oil and gas will remain key drivers of economic development in the hydrocarbons-rich countries in the Bank's area of operation and offer real opportunities for the Bank to pursue its goals of encouraging economic and political transition.

The social and environmental impacts of energy projects, transparency of payments to host governments and management of oil and gas revenues have also risen up the political agenda. The resulting initiatives, including the Extractive Industries Transparency Initiative, Publish What You Pay and the Global Gas Flaring Reduction Initiative, increasingly define the framework in which oil and gas projects are conducted. The Bank should embrace these initiatives and require that all parties to the projects they fund implement the principles of these initiatives. Such projects should have a valuable demonstration effect for others operating in the sector, as well as maximising the positive and minimising the negative impacts of oil and gas projects.

The Bank has built up a wealth of experience in operating in all stages of the oil and gas supply chain and still has a vital role to play in this area in the future. The Bank is seen as providing both comfort to and a lead to commercial banks through its pioneering of project-based loans to transition countries. As the environment in which it operates has shifted, so too have the opportunities for the Bank to pursue its transition objectives in the oil and gas sector.

The largest Russian oil companies are now generally able to raise finance on the international commercial lending markets, reducing the need for EBRD involvement in all but the largest of their projects. However, the Bank has an important role to play in moving foreign lending down the hierarchy of Russian companies, embracing some of the smaller players and encouraging the commercial banks to do likewise.

The oil industry in Russia has become much more competitive over the past five years, the re-nationalisation of Yuganskneftegaz notwithstanding, although the industry remains dominated by a small number of large companies. The same is not true of the Russian gas industry which remains monopoly-controlled through state-owned Gazprom, other gas producers remaining dependent upon Gazprom for access to gas pipelines and markets. It is unlikely that the structure of the Russian gas market will be susceptible to external pressure for change, so the Bank should, perhaps, support the activities of second-tier gas producers in Russia, helping to build up a viable independent gas sector. The Bank's leverage may help such companies secure guaranteed access to pipelines and markets. Other gas projects that the Bank might become involved in are the proposed offshore gasfield developments and associated LNG terminals, which will require huge investments and probably involve foreign, as well as Russian, partners. The Bank should continue to raise the issue of open access to Russian gas pipelines as part of its on-going policy dialogue with the Russian government. For the gas sector, the inability of producers other than Gazprom to gain guaranteed access to the pipeline system for their output is a major barrier to increasing competitiveness in the industry. Likewise, the inability of oil producers to export their associated gas through the pipeline network is a contributor to gas flaring and venting in Russia.

In the Caspian Sea region, as in Russia, the Bank's key role in upstream oil and gas projects could well be in supporting smaller players, helping to create a vibrant 'independent' oil sector populated by smaller companies. In Azerbaijan offshore activity by the major oil companies (except those involved in the ACG and Shah Deniz projects) has virtually ground to a halt. A growing number of smaller, onshore projects are being taken up, though, often reworking highly depleted fields, which may involve a heavy commitment to environmental remediation.

Several potential opportunities exist for the Bank to become involved in oil and gas transportation projects, particularly in the Balkans where various pipelines have been proposed to bypass the environmentally sensitive Turkish Straits. These projects still have to overcome political hurdles before they can move forward, but it is likely that one or more such pipelines will be built in the next five to ten years. The Bank's involvement in transportation projects in the Caspian Sea region may focus on the construction of ships and port facilities to move oil from east to west across the sea, rather than on the big pipeline projects that have dominated the sector so far. The Bank's involvement may help to ensure that vessels used for the transportation of oil across the environmentally-sensitive Caspian Sea is undertaken in state-of-the-art vessels with the highest levels of environmental protection.

Downstream, the growing global demand for light, sweet products (ultra-low sulphur transportation fuels) opens up opportunities for the upgrading of refining capacity in the Bank's countries of operation to meet tightening product specifications in most export markets. Such investments would also have a beneficial local impact, improving the quality of oil products sold on the local market, thereby reducing local pollution.

Since the Bank reacts to requests for its involvement, rather than actively seeking projects in which to invest, it does not make sense for it to impose quotas on itself for particular types of project. The Bank is under external pressure to promote renewable energy projects in favour of fossil fuel projects, but should resist pressure to impose a 'renewable energy quota' on its lending. The renewable energy industries in the Bank's countries of operation are in their infancy, at best, and any such quota would only reduce the Bank's involvement in energy projects generally. Perhaps the Bank could consider a renewable energy investment growth target, similar to that adopted by the World Bank. It might also consider promoting the use of renewable energy technology in and around the hydrocarbons projects that it supports. The Bank should be very intentional in promoting the work that it does do in the renewable energy field. Because of the nature of renewable energy projects, they will always be smaller than the large and highly visible oil and gas projects. The Bank needs to ensure that its work in the renewable energy field is a visible as possible.

The Bank should also sign up to the Global Gas Flaring Reduction Initiative and make adherence to the principles of that initiative a pre-requisite for its involvement in oil and gas projects. It should take a similar stance with regard to transparency, requiring project partners and host governments to adhere to the principles of the Extractive Industries Transparency Initiative as far as possible.

The oil and gas sector plays a major role in the economies of the transition countries and the Bank needs to remain actively involved in the sector. It has a vital role to play not just in mobilising finance to help the economic development and transition of these economies, but also in ensuring that the projects that it supports operate to the very highest standards environmentally, socially and in terms of transparency and governance. The Bank, along with other IFIs and pressed by NGOs, has been at the forefront in setting the agenda for the regulation of foreign investment in transition countries. It should continue providing a model for others to follow and a benchmark for them to be measured against. While initiatives such as EITI provide a desirable way forward for the management of the finances of large energy projects, the initiative has yet to be taken up in most of the Bank's countries of operation. The Bank, as a primary facilitator of foreign capital can play a leading role in encouraging the take-up of EITI in its countries of operation. In those countries where the initiative has not been taken up, the Bank should seek to apply its principles on a case by case basis to the projects in which it becomes involved.

Energy policy is still evolving in the EBRD's countries of operation and the Bank is perhaps in a position to influence this evolution to some degree. All of the major hydrocarbons resource holders among the Bank's countries of operation suffer to some degree from a lack of transparency of contracts and a degree of arbitrariness in dealings with privately-owned oil companies (both domestic and foreign). Ongoing policy dialogues between the Bank and host governments can usefully be pursued in areas such as the acceptance of PSAs for large, capital-intensive projects, the sanctity of contract, the creation and maintenance of a level playing field for all investors and open access to pipeline systems regulated by a professional authority independent of government.

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