INTERNATIONAL ENERGY AGENCY

RUSSIA ENERGY SURVEY 2002

IN CO-OPERATION WITH THE ENERGY CHARTER

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ENERGY AGENCY
9, rue de la Fédération,
75739 Paris, cedex 15, France

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six* of the OECD's thirty Member countries. The basic aims of the IEA are:

- To maintain and improve systems for coping with oil supply disruptions;
- To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- To operate a permanent information system on the international oil market;
- To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- To assist in the integration of environmental and energy policies.

**IEA Member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.*
The European Commission also takes part in the work of the IEA.

ORGANISATION FOR
ECONOMIC CO-OPERATION
AND DEVELOPMENT

Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed:

- To achieve the highest sustainable economic growth and employment and a rising standard of living in Member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;
- To contribute to sound economic expansion in Member as well as non-member countries in the process of economic development; and
- To contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

The original Member countries of the OECD are Austria, Belgium, Canada, Denmark, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The following countries became Members subsequently through accession at the dates indicated hereafter: Japan (28th April 1964), Finland (28th January 1969), Australia (7th June 1971), New Zealand (29th May 1973), Mexico (18th May 1994), the Czech Republic (21st December 1995), Hungary (7th May 1996), Poland (22nd November 1996), the Republic of Korea (12th December 1996) and Slovakia (28th September 2000). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

FOREWORD

Because of Russia's role as a key oil and gas exporter, the Russian energy sector is of key importance to the country's economic success, as well as to world energy markets. Reforms are essential to enable Russia's energy sector to keep pace with domestic energy demand growth in a period of strong GDP growth, while yet seizing export opportunities. Success will depend upon the creation of a stable and competitive investment environment, energy price reform, corporate transparency, dramatic improvement in energy efficiency and proper safeguards against the adverse environmental impacts from increased energy production and use.

Following the methodology used to analyse IEA member countries, this survey provides insights into the issues each sub-sector faces, after a long period of low investment in maintenance and reserve replacement. In addition to the detailed descriptions of all energy sub-sectors with supporting statistics, observations are made and conclusions drawn to highlight areas where progress is needed if Russia is to attract the necessary investments, both domestic and foreign, to ensure its own, and its neighbors', energy security.

The timing of the Survey relates closely to that of the new Energy Strategy of the Russian Federation to 2020, approved by the Government in October 2001. Like the IEA's 1995 Survey of Russian Energy Policies, it was carried out by the IEA within the framework of the Joint Declaration of Co-operation signed by the Russian Government and the IEA in 1994. It was undertaken with the co-operation of the Energy Charter Secretariat, for which I would like to thank its Secretary General, Dr. Ria Kemper.

Robert Priddle
Executive Director

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The Russian Government provided indispensable help. Special thanks is given to Deputy Minister of the Ministry of Energy of the Russian Federation, Anatoly B. Yanovsky and Alexei M. Mastepanov, Head of Department, whose expert advice and help made this survey possible. The following individuals and organizations also contributed to this book: Alexander V. Misiulin, Oleg B. Pluzhnikov (Ministry of Energy), Vitaly V. Bushuev, Marina R. Lastovskaya (Institute of Energy Strategy), Vladimir V. Severinov, Larissa A. Patrikeeva (Ministry of Atomic Energy), Andrey A. Konoplianik (Energy and Investment Policy & Project Financing Foundation (ENIP&PF)), Anatoly I. Skril (RosInformUgol) and Igor A. Bashmakov (Center for Energy Efficiency (CENEf)).

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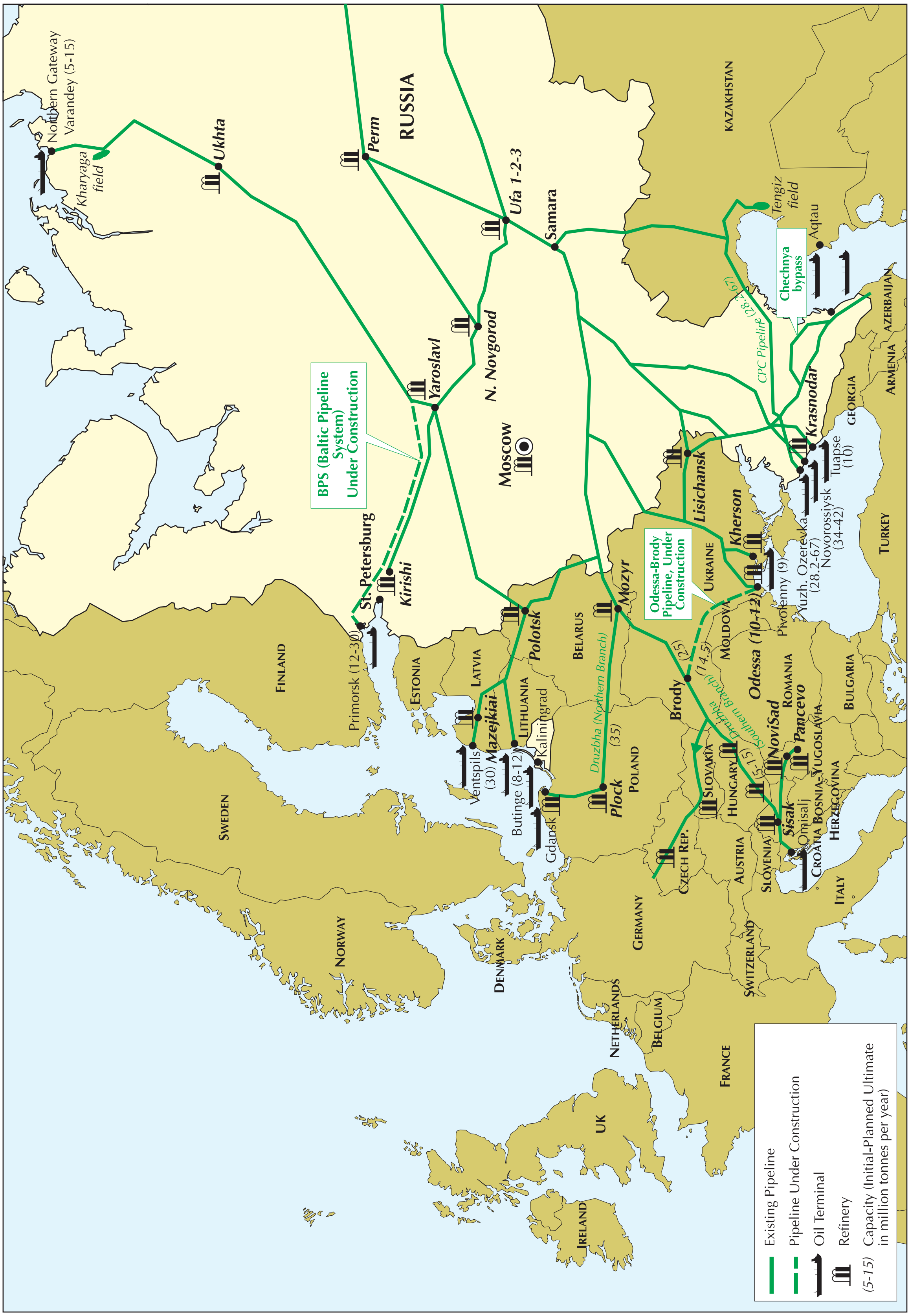

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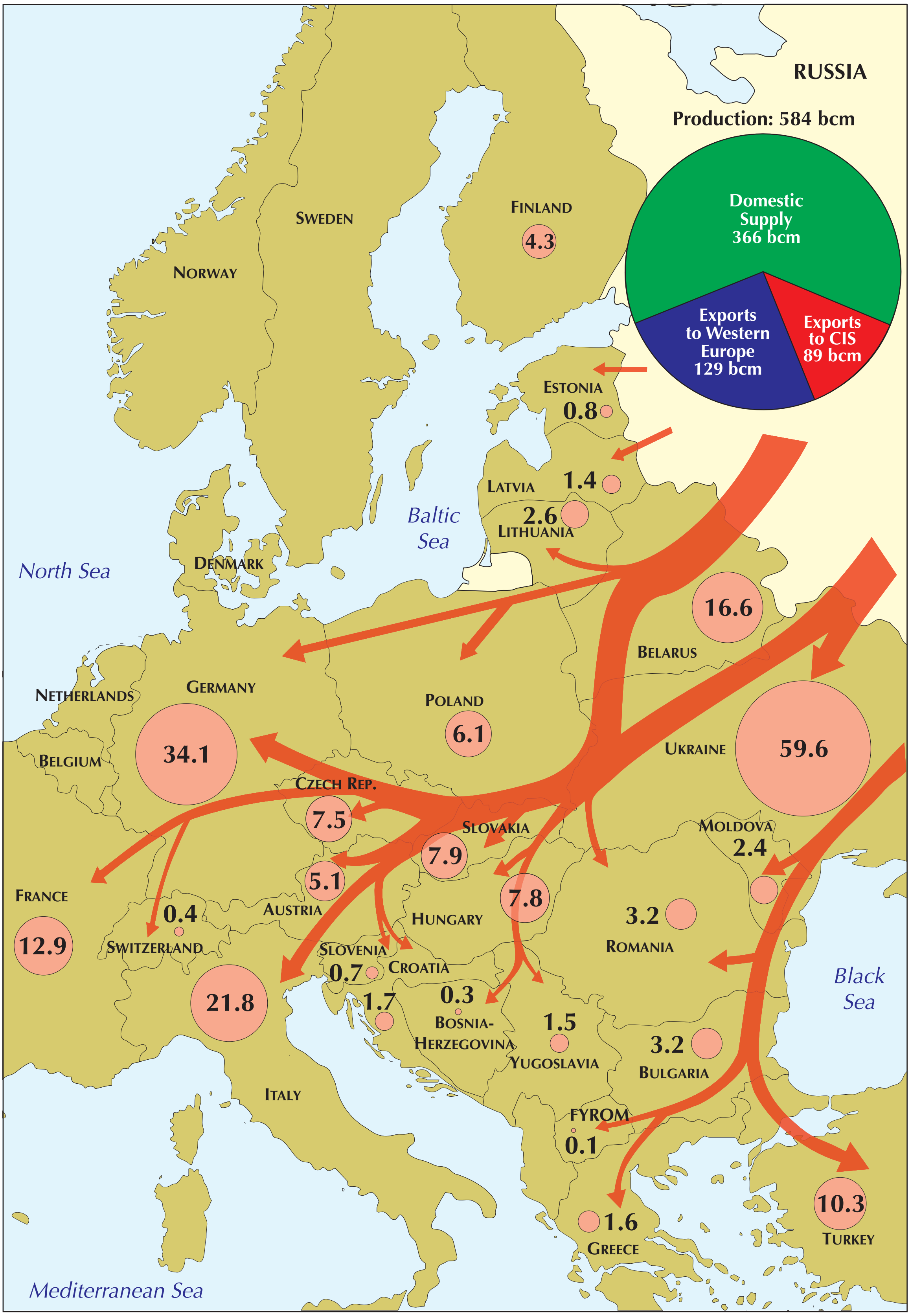

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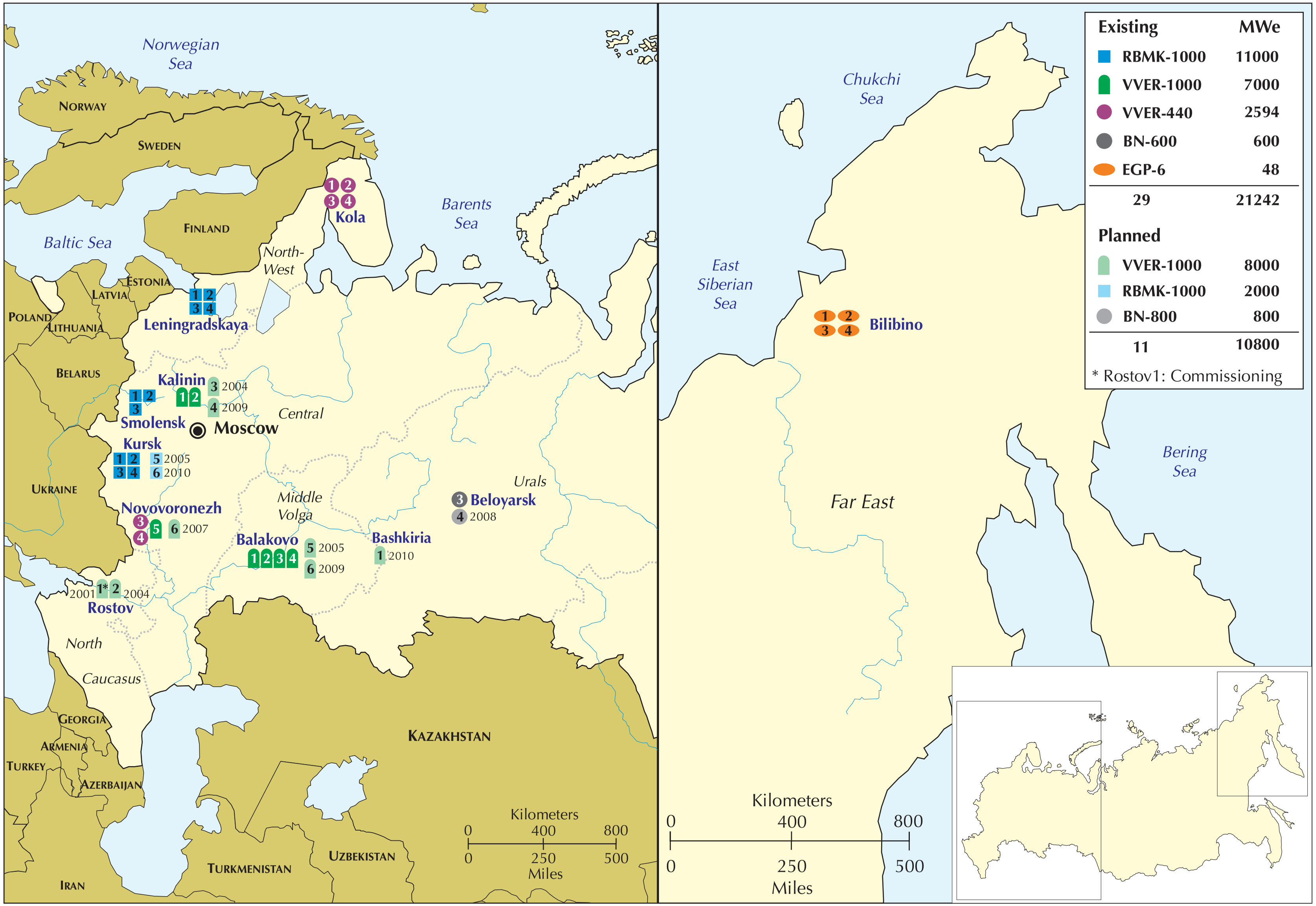

Source: Main Provisions of the Energy Strategy of the Russian Federation to 2020, November 2000.

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INTRODUCTION

The IEA conducted a survey of Russian energy policies during the summer and autumn 2000. The resulting report assesses developments since 1995, when the IEA published its last Survey and reflects the continued co-operation of the IEA with Russia in the framework of the Joint Declaration of Co-operation signed in July 1994.

In addition to the detailed descriptions and supporting statistics for all energy sub-sectors, the 2001 Survey provides insight into the energy security issues each sub-sector faces given the poor state of the overall energy sector after a long period of low investment in maintenance and reserve replacement. This is especially important to Russia in its effort to sustain the economic growth experienced since its financial crisis in 1998. The Survey also assesses developments since 1995 in the areas of energy efficiency, environmental impacts of energy use and production, and nuclear safety.

The timing of the Survey parallels that of the new Energy Strategy of the Russian Federation to 2020. This Survey contributes to discussion on the Russian energy policy outlook and the Russian government's efforts to elaborate and effectively implement economic reforms. These reforms are critical for the energy sector to be able to match energy demand in this period of strong GDP growth. Increasingly, the energy security of Russia and its export markets are dependent on the creation of a stable and competitive investment environment, energy price reform, corporate transparency and dramatic improvement in energy efficiency.

The survey team was composed of experts from the IEA Secretariat and IEA member countries. The members of the survey team were:

Ole Anders Lindseth (Team Leader)
Director General, Ministry of Petroleum & Energy Norway

Olivier Appert
Director, Long Term Co-operation and Policy Analysis Office, IEA

Hans Kausch
Former Head of Division for Europe, Middle East and Africa, IEA

Len Coburn
Director, Office of Policy Analysis, Trade & Investment for Europe, NIS and the Middle East, Department of Energy, USA

Miroslav Hrehor
Nuclear Safety Administrator, Nuclear Energy Agency (NEA/OECD)

Jonathan Stern
Royal Institute of International Affairs, Gas Strategies, London, UK

Matthew Sagers
Director of Energy Services, PlanEcon Inc. Washington DC, USA

Jean-Christophe Fueg
Formerly of the Non-Member Countries Division, IEA

Pierre-Marie Cussaguet
Formerly of the Country Studies Division, IEA

Isabel Murray
Russian Desk Officer, Non-Member Countries Division, IEA

Karl Petter Waern
Senior Expert, The Energy Charter Secretariat

Rachel Swain
Consultant, The Energy Charter Secretariat

Sydney Fremantle
Consultant, The Energy Charter Secretariat

The Team held discussions with representatives of the following organizations:

- Ministry of Energy
- Ministry of Atomic Energy
- Ministry of Economic Development and Trade
- Ministry of Natural Resources
- Ministry of Finance
- Ministry of Foreign Affairs
- Federal Energy Commission
- GosAtomNadzor
- Federal State Duma
- Administration of Sakhalin
- Administration of Khanty-Mansiisk
- Yukos
- RAO UES
- GasExport
- Itera
- Nuclear Safety Institute of the Russian Academy of Science (IBRAE)
- Kourchatov Institute
- Center for Energy Efficiency (CENEf)
- Petroleum Advisory Forum
- Russian Social-Ecological Union
- Ecojurist

These meetings were complemented by those held earlier in the summer 2000 during a smaller IEA preparatory Survey mission to Moscow with drafters of the Russian Energy Strategy from the many institutes which support the Ministry of Energy, as well as with Gazprom and RAO UES, LUKoil and GosKomStat.

1. MAIN CONCLUSIONS AND RECOMMENDATIONS

ENERGY REFORM A KEY FACTOR IN ECONOMIC REFORM

From 1995 to 2000, Russia took important steps forward in energy-sector reform, but many of the goals the Russians set in 1995 were not achieved, due largely to the poor performance of the overall economy. Energy reforms must be implemented if Russia's Economic Development Plan is to succeed. Russia's new energy strategy rests on the assumption that the growth of the economy since 1999, fuelled in its early stages by external factors, will take root and continue. It is not certain that the energy sector can match increasing energy demand during a period of strong GDP growth.

The *Main Provisions of the Russian Energy Strategy to 2020* calls for hefty increases in energy supply to match rising demand. It aims to decrease an over-dependence on natural gas, reducing the share of natural gas in Total Primary Energy Supply (TPES) from about 50% in the 1990s to between 42% and 45% in 2020. The share of coal would increase from 16% in 1998 to 22% in 2010 and to between 21% and 23% in 2020. Nuclear energy would rise to 6% in 2020 from its current 5%. Oil's share in TPES would remain practically unchanged. The energy sector's total investment requirements from 2001 to 2020 are estimated at somewhere between $550 billion and $700 billion.

KEY PRIORITIES

The Investment Environment

Improving corporate governance and transparency and enforcement of the rule of law. The government must continue to develop and apply a legal and regulatory framework covering corporate responsibility and shareholder issues (the Civil Code, the Law on Banking, and the Law on Bankruptcy). Strong co-operation is needed between the executive body and the *Duma*, as well as between Moscow and lower levels of government. Co-ordination and co-operation are the key to enforcing laws, promoting good corporate practices and dealing with corruption.

Improving the investment environment. Throughout the 1990s, barriers to investment hampered the energy sector's ability to maintain capacity and replace reserves. Despite the growing need for investment, many barriers remain, reducing Russia's ability to attract private investment, both domestic and foreign.

Continuing improvement of the Tax Code. Completion of Part II of the Tax Code and its effective implementation are essential. These are the final steps in Russia's comprehensive fiscal reform, with important implications for enterprises in the energy sector. The approach to oil sector taxation reform encompassing a relatively low royalty plus an excess profits tax (together with the normal corporate profits tax) – is a positive move towards a more progressive and profit-sensitive fiscal regime and away from the current approach, based on gross revenues. Although recent changes (effective in 2002) streamline and simplify taxation, the overall goal to move to a more profit-based structure of taxation has not yet been achieved. This is especially important in the mineral resource sector, where initial investment costs are high and payouts are stretched out over the long-term. A specific tax regime for mineral resources has to be put in place. This is standard practice in most countries.

Completion of the Production Sharing Agreement (PSA) regime. Petroleum licensing and operations require a comprehensive, clear and stable legal framework. Completion of the PSA regime and its efficient implementation will provide a mechanism to attract investment and bridge the gap while the Tax Code and investment laws are put in place. Key tasks are passage of the normative acts, the PSA chapter of the Tax Code and further amendments to the PSA law.

Energy Price Reform

Implementing energy price reform. The best way to stimulate efficient use of energy is to ensure that prices cover costs. The *Main Provisions* calls for raising and realigning energy prices to shift the balance in energy demand and the shares of different fuels in TPES. The government intends to use market prices to eliminate, as soon as possible, the incentive to switch from other fuels to gas. The *Main Provisions* set very high targets for domestic gas prices. They would be comparable to European import prices by 2007. Higher coal prices leading to higher electricity and central-heating prices will follow this change.

The impact of higher prices on future demand needs assessment. Will future electricity consumption actually require as much new capacity as projected, given the likelihood that higher prices will curb demand?

A determination to raise prices is commendable, but could raise problems. The ambitious price plans may lead to serious problems for industries and regions – bankruptcies, social hardship and dislocation. Contingency plans must anticipate and resolve these problems.

Establish a clear plan and timetable. A schedule of quarterly price increases for each customer class should reflect both inflation and export prices. It is economically sound to require residential customers pay higher prices than industry and power generators, but individuals and families also need the means to control their energy consumption. It is unacceptable to raise prices without giving consumers such control.

Remove energy subsidies. Commendable plans to end electricity cross-subsidies by 2002 should be implemented and extended to all energy sectors. Targeted assistance to vulnerable social groups is more effective and economically efficient than extensive price subsidies.

Progress in resolving the non-payment problem needs to continue. Impressive progress has been made toward normal payments in cash for energy consumption since 2000. As tariffs increase, continued vigilance will avoid a relapse into the non-payment cycle.

Strengthening the Role and Independence of Regulatory Bodies

The government should strengthen and ensure the independence of federal and regional regulatory bodies. The Federal Energy Commission and its regional counterparts, the newly established Commission on Oil and Gas Pipeline Use and the Anti-Monopoly Ministry all need to be strengthened. This will ensure a "level playing field" for competition in all natural-resource sectors and in the electricity and heat industries. This new system should include third-party access, transparent tariff-setting based on full costs and licensing rules for new players in the markets.

Improving Energy Efficiency

The IEA fully supports the *Main Provisions'* emphasis on reforming the fuel price structure as the key to rational and efficient energy use.

The need for consumer control. Business and residential consumers will consume energy efficiently if empowered to do so. It is critical that consumers gain control of their own energy consumption through metering, thermostats, standards and labels and building regulations.

Economic competitiveness of energy-efficiency investments. The new "Energy Efficiency Economy" programme commendably outlines specific investment needs to improve efficiency in energy production and consumption. With limited funds and an unattractive investment environment, Russia must establish priorities to maximise efficiency gains. Many low-cost investments can foster the consumer awareness and control that are essential to efficient energy consumption.

A regional approach to energy efficiency is essential. Grass-roots support is vital to improving energy efficiency. Moscow's efforts must be supported by regional governments and citizens. A study of "best practices", organized by region, could help muster local support.

Energy Sector Restructuring

Effective implementation of the electricity industry restructuring plan. This is essential for the sector to meet increasing electricity and heat demand. There is bound to be resistance from various interested groups including regional governments, industry and the general public. The three-stage plan, approved by the government in 2001, introduces competition at the generation and distribution level. In the first stage of reform, retail prices will remain strictly regulated, although tied to wholesale prices. All firms are to be guaranteed non-discriminatory access to the high and low voltage grids. The plan uses the approach of many OECD countries in unbundling the electricity sector. It is expected to facilitate trade among regions.

Clarify the relationship between Gazprom, independent producers and others. The appearance of independent companies like Itera – a substantial independent user of the pipeline network – is to be welcomed, subject to a full and transparent clarification of the relationship between it and Gazprom. Substantial ownership or take-over of Sibur by Gazprom would be highly undesirable and anti-competitive for associated-gas production. Regulation can address this problem only by setting a regulated fee for gas processing. By far the best solution would be to introduce competition between owners of processing plants, but this cannot happen while there is a monopoly, that is majority-owned by the major gas production and transmission company.

Market-share targets can support the competitive position of new companies. Even with aggressive price reform and favourable access terms, Gazprom is so dominant that it will be extremely difficult for new companies to compete. Market-share targets may be the most workable solution. The government and/or the regulatory authority should require Gazprom to reduce its market share – in the whole market or in defined sectors – to a certain percentage by a certain date.

The Gazprom/ Gazexport monopoly on exports to Europe needs review. Such a review is especially important in light of developments in transmission charges and access rules within Russia. As the European gas market becomes more competitive, with short-term trading and transparent pricing, sellers of Russian gas will see opportunities in European markets. They may face serious barriers to entry. The terms on which they can gain access to the Ukrainian transit pipelines will be critical.

Further changes to the structure of Gazprom should be kept under review. This applies particularly if gas-to-gas competition and third-party use of Gazprom's pipeline network remain limited. In that case, or if real competition fails to emerge, the government will need to assess the advantages and risks of the break-up of the company.

Overall economic reform is critical. General improvements in transparency and corporate practices will make energy businesses more attractive for investors and private shareholders. At the same time, restructuring the energy sector is essential to achieve broad economic reform.

Trade and Transit

Ratification of the Energy Charter Treaty. Ratification of the Energy Charter Treaty and adoption of its energy-transit regime by Russia and neighboring states would help de-politicise transit negotiations between FSU states. Ratification of the Charter Treaty by Russia would send positive signals to entice other transit countries into more predictable and transparent transit business practices. It would help avoid the construction of expensive pipelines, such as the one now planned to by-pass Ukraine. Ratification of the Treaty would provide a common legal basis for gas transit from and through the CIS countries, including the Central Asian states. It would provide all parties with an international legal foundation – including a mechanism for international dispute settlement – on which to base transit grievances and receive compensation for transit violations. Russia, after ratifying the Treaty, would be bound by the WTO rules for energy trade and trade in energy equipment (see Annex A).

International initiatives should support the resolution of outstanding problems. OECD, Energy Charter process and EU initiatives, including the EU-Russian Energy Partnership, should help the parties to create a commercial framework that provides for adequate investment in transit networks. They should also push for equitable gas prices and transit tariff arrangements. Commercial parties need support in resolving the problem of transit through Ukraine.

Nuclear Power

Targets for increases in nuclear-power generating capacity are very ambitious. In January 2000, 29 commercial nuclear reactors operated within Russia at nine sites built between 1971 and 1993. Within the next eight years, all the units belonging to the first generation, which were designed before the issuance of basic safety regulations in 1973, will complete their planned lifetimes of 30 years. Units of the second generation will complete their lives over the next 9 to 19 years. Extensions beyond design lifetime are envisaged, and plans to increase nuclear-power generating capacity are very ambitious. Under a low-growth scenario, the plan for the next 20 years is to build almost as much new nuclear capacity, approximately 20 GW, as was built during the 1970s and 1980s. The goal is to reach annual nuclear electricity production of 235 TWh. The goals are even higher under a high-growth scenario, with a target of 30 to 32 GW of new plant capacity and annual output of 340 TWh, nearly three times that of 1999.

Lifetime extensions will require major investments. Operating existing nuclear units beyond 30 years will require large financial resources and the special attention of both the state company, *Rosenergoatom* and the independent safety regulator, *GosAtomNadzor* (GAN), especially for the first-generation units.

Adequacy of resources for the safety regulatory body. GAN should analyse its financial needs for both current and future tasks and submit its assessment of resource needs to the appropriate authorities. The tasks are manifold and important: ongoing re-licensing and in-depth safety assessment of existing units, safety-upgrading programmes, residual-lifetime evaluation and extension and preparations for overseeing decommissioning of nuclear power plants.

Energy and Environment

The need to protect the environment especially given the outlook for economic growth. Russia took major steps toward environmental policy reforms during the 1990s, along with the overall transition to a market economy and the devolution of powers to regional governments. These reforms have, however, met a number of severe problems, largely due to general socio-economic decline, inflation and budgetary shortages. The sharp decrease of emissions of pollutants from the energy sector over the 1990s was due mainly to the economic downturn. With the outlook for economic growth and increased energy demand, the impact of energy production and use on the environment will increase unless major improvements are made in energy efficiency and environmental management. This is especially worrisome in light of the stated intent to limit the increase of natural gas in the energy balance in favour of coal and nuclear power. An in-depth assessment of the environmental effects of this policy should take priority.

The increased environmental impact of coal production needs scrutiny. Although slightly diminished since the early 1990s, the environmental damage done by coal will increase with higher coal production, absent major investments in clean coal technology.

Solutions should tend towards a less prescriptive and more goal-oriented regulatory framework. It is encouraging to see inter-ministerial groups led by the Ministry of Energy tackling environmental regulatory issues that have blocked project development under PSAs. Solutions should tend towards a less prescriptive and more goal-oriented regulatory framework, which tells companies what needs to be done and leaves them to find the most cost-effective ways to do it. This will encourage ingenuity and new and improved technology. This goal-oriented approach has to be extended in the energy sector of the Russian economy.

Russia is a signatory to most recent international treaties and conventions relating to energy and the environment. It is often more successful in fulfilling these commitments, mostly as a result of economic decline, than in enforcing its own domestic laws and regulations. Many see the international disciplines as a possible means of developing frameworks necessary for implementing domestic aims. Under the Kyoto Protocol, Russia is committed to stabilise emissions of six greenhouse gases at 1990 levels by the period 2008-2012. The much lower levels of GHGs in Russia due mostly to economic decline over the 1990s have opened opportunities for emissions trading. Such trading, together with the Joint Implementation forseen by the Kyoto Protocol could help raise funds and attract investment to improve Russia's energy efficiency.

2. OVERVIEW OF ENERGY POLICY DEVELOPMENTS

EXECUTIVE SUMMARY

Major Economic Developments in Russia: 1995-2000

From 1995 to 2000, Russia made important forward steps in energy-sector reform. Yet it could not achieve many of the goals set in 1995, due largely to the poor functioning of the overall economy. A brief overview of the major economic developments in Russia over the period puts into context developments in the energy sector and in energy policy thinking. One important aspect of the new Russian Energy Strategy to 2020 is that it is an integral part of both the new economic programme and the restructuring of the economy. In the areas of fiscal and price reform, the strategy depends on the successful implementation of the Economic Development Plan of the Ministry of Economic Development and Trade. Given the energy sector's size, energy reforms must be implemented if that Plan is to succeed.

The Investment Climate

Growth since the economic crisis of August 1998 has been fuelled mainly by external forces: high prices for exported oil and the devaluation of the rouble to 25% of its earlier level. Increased pressure has been placed on the energy sector to meet rising energy demand. Ministry of Energy estimates of investment needs in the period from 2001 to 2020 range from $550 billion to $700 billion. In the 1990s, barriers to investment limited the energy sector's ability to maintain capacity and replace reserves, not to mention increase generating capacity and production. Price reform and continued success in tackling the non-payment problem will be necessary as energy prices increase. Effective implementation of the Tax Code will help enhance the competitiveness of the fiscal environment. More work is needed to streamline and clarify elements of the legal framework to support the new market economy and attract investment. They remain inconsistent with older laws and subject to arbitrary and highly discretionary interpretation and implementation. The poor delineation of federal and regional powers and frequent quarrels among regulatory agencies create a fertile environment for corruption and undermine the credibility of contracts. One key to gaining investor confidence will be progress in corporate management and better defence of shareholder rights through increased transparency and openness. Foreign investors have focused on the Law on Production Sharing Agreements. It could provide the stability and guarantees necessary until the various Russian codes, laws and regulations are adopted and implemented. Although it is mainly targeted at the upstream oil sector, this ready-made framework could be used in all areas of natural resource development.

Climate for Energy Sector Restructuring

The main purpose of the initial restructuring of the energy sector in the early 1990s was to introduce commercial disciplines and private capital. The focus then was not on introducing competition, reducing barriers to entry or eliminating other inhibitions to entrepreneurial investment. Now, however, restructuring definitely aims to create favourable conditions for investors so long as they abide by their licensing obligations to ensure reliable supplies. The State plays an important role as the main shareholder and regulator of the natural monopolies. It has put a priority on the creation of a competitive environment in the gas and electricity sectors and on encouraging the development of independent producers by creating non-discriminatory access to their supply systems.

MAJOR ECONOMIC DEVELOPMENTS IN RUSSIA: 1995-2000

During the second half of the 1990s, Russian government and industry increasingly acknowledged the world economy's influence on their own. Energy's major role in the Russian economy and the country's very heavy dependence on natural-resource exports make Russia highly vulnerable to swings in world prices. This vulnerability will continue until its investment environment improves and attracts a more balanced cross-section of economic activity. The financial crisis in 1998 heightened the realisation of these facts. In many ways, it became a turning point for policy decisions, energy-sector restructuring and the investment outlook.

The Pre-Crisis Period: 1995 to August 1998

From 1995 through 1997, Russia made progress in monetary policy and in the regulation of commercial banks and financial markets. Yet, despite these positive steps toward the creation of a market economy, unsustainable trends became increasingly apparent:

- widening budget deficits at all levels;
- a spiral of official debt crowding out investment in the real economy;
- increasing use of money surrogates and the demonitisation of the economy through barter;
- a concentration of economic activity in large financial industrial groups (FIGs), many of which enjoyed special relations with government institutions;
- a lack of transparency and good corporate practices in these FIGs;
- an unpredictable and burdensome tax system based on gross revenues, rather than profits, and aimed at meeting short-term budget needs as opposed to long-term investment.

Nonetheless, modest gains in output, in living standards and in the capitalisation of financial markets were visible in 1997. Indeed, an exaggerated perception of improvement bred complacency and thus slowed the reform process. Substantial inflows of foreign capital in late 1996 and the first half of 1997 fuelled a sense of security, but they consisted largely of short-term portfolio investments rather than direct investment. They went primarily into government securities to finance the increasing public debt.

A root cause of this distortion lay in the regressive and overly burdensome tax system, aggravated by poorly functioning tax collection. The law is often not enforced. The corporate culture neglects the interest of shareholders. Companies regularly evade taxes. All these trends invited abuse. New corporate structures were created specifically to "limit" tax obligations. These factors eroded tax revenues directly and gnawed at them indirectly by stifling investment in the real economy. The unpredictable, regressive and complex tax regime made investment in long-term projects uneconomic.

More attention went into "emergency" federal tax-collection drives – often scarcely legal – than into reforming the fiscal system. This further weakened the stance of private creditors *vis à vis* insolvent enterprises. Commercial banks failed to develop profitable loan portfolios and to fulfil their role as financial intermediaries. Despite progress in the regulation of commercial banks, most banks came to depend on large portfolios of government securities. By January 1998 this market had grown to $64 Billion. Annual yields of government securities peaked at over 200%. Even if industry actually *had* been open to outside investment, it could not have competed with government offerings of high-interest, low-risk and highly liquid instruments. Arguably, Russian companies remained cash-starved despite the booming financial markets largely because of the government's crowding-out effect.

By the beginning of 1997, the gap between the financial and real markets began to close. Gazprom, the world's largest gas producer, distributor and exporter, issued a $425 million equity offering. Lukoil and a dozen other Russian companies began offering American Depository Receipts (ADRs) on the New York Stock Exchange. The number of enterprises willing to submit to audits by international accounting standards grew. Russian oil companies began to borrow heavily from international banks, using their oil exports and reserves as collateral. Russian oil companies accumulated debt estimated at $25 Billion – about 10% of Russia's total foreign obligations.

At the time, Russian oil-company debt tied to oil export revenues was considered a relatively easy way to acquire investment funds. When world oil prices dropped dramatically in 1998, however, repayment of interest and principal drained company revenues. By the third quarter of 1998, almost 70% of the export revenues of Russia's top twelve exporters went to meet financial obligations. Low oil prices and lower oil-export and tax revenues severely weakened both the oil sector and the State budget. The budget impact in 1998 was almost $15 billion. The effect on the oil companies was even more severe because most of their domestic sales did not yield cash. Export revenues mainly financed operating expenditures and some capital spending. When the financial crisis in Asia began to ripple through other emerging markets and economies in transition, Russia was already close to a major financial collapse.

Some positive developments occurred in other parts of the energy sector. Domestic gas prices for industry increased and reached 55% of export prices by 1997. Industrial electricity prices also rose, but cross-subsidies in favour of the residential sector remained, and the non-payment of electricity bills (with cash payment below 20% in 1998) starved the energy sector of cash. The coal industry continued its restructuring, but very slowly, hampered by lack of finance to support relocation and retraining programmes related to the closure of uneconomic mines.

The Post-Crisis Period: August 1998 to 2000

In August 1998, the combined impacts of the Asian financial crisis and low oil prices brought down the fragile, speculative Russian market. Russia might have avoided the plunge into financial crisis if only one of these two exogenous shocks had occurred. In the event, the crisis had some desirable consequences. It forced a sense of reality – on industry, which had to restructure and streamline costs, and on policy makers in government and the Duma, who had to review priorities and move forward on the laws needed to attract direct investment. The quick passage of laws on Production Sharing Agreement (PSA), which until then had been blocked in the Duma, became a key government aim. The laws were passed in February 1999, but necessary regulations to implement the PSA remain incomplete, three years later.

The initial rouble devaluation helped bring some economic stability and a boost to domestic industry. The rouble fell by about 50% in real terms, providing a tremendous benefit to domestic producers and exporters. The oil sector, having lost its easy access to funding in August 1998, still faced capital constraints. But, since 90% of its spending is denominated in roubles, the devaluation brought a dramatic decrease in costs and an increase in the purchasing power of export dollars. This balanced to some extent the adverse impact of dollar-denominated repayment of export-tied debt. Companies such as Lukoil cut production costs from \$55/tonne in 1997, to \$18/tonne (\$2.50/bbl)[1]. Many Russian oil companies used the period of lower oil prices to streamline costs and drop unproductive operations. Some analysts argue, however, that even if oil prices had not increased so dramatically in 1999, critically needed restructuring and streamlining would have continued.

Russian industrial output increased by more than 8.1% in 1999 and by 9% in 2000, largely because the devaluation of the rouble led to import substitution and a better financial situation for industrial enterprises. High export prices also spurred vigorous growth. These exogenous factors led to increases in the production of plant and equipment, construction materials and oil products. The replacement of relatively expensive imported goods by Russian-made goods boosted the population's real disposable income in 1999 and 2000. This fuelled growth in the clothing and food industries and in sectors that provided them with raw materials and semi-finished products.

The electricity and gas sectors fared much worse. The devaluation, combined with a freeze on domestic fuel prices, reduced domestic gas prices to about a fifth of their level before August 1998, from about \$56 per thousand M^3 to \$11 per thousand M^3. Average consumer electricity prices dropped to a penny per kWh, a sixth of the price in OECD countries. The financial health of the electricity and gas sectors, already weakened by the non-payments problem, deteriorated still further. Pressure from Gazprom and RAO UES for increases in domestic gas and electricity tariffs should be

1. This did not include VAT and excise taxes, which would add \$7/tonne to costs.

Table 2.1 Key Russian Economic Statistics, 1992-2000

Annual growth rates (%)	1992	1993	1994	1995	1996	1997	1998	1999	2000
GDP	– 15.5	– 8.7	– 12.7	– 4.1	– 3.4	0.9	– 4.9	5.4	8.3
Industrial output	– 18.0	– 4.0	– 21.0	– 3.0	– 4.0	1.9	– 5.2	8.1	9.0
Fixed capital investment	– 40.0	– 12.0	– 24.0	– 13.0	– 18.0	– 5.0	– 12.0	5.3	17.7
CPI inflation	2509	840	215	131	21.8	11.0	84.4	36.5	20.2
PPI inflation	3278	895	233	175	126.0	7.0	23.0	71.4	31.6
Implicit GDP deflator	1508	888	308	163	44.2	14.5	16.3	64.7	37.1
M2				113	30	30	36	57	62
Interest rates, lending				320	147	46	42	40	18
Interest rates, deposits				102	55	16	22	14	5
ILO-unemployment, % (Level, end of period)	4.8	5.9	7.5	8.2	9.3	9.0	11.8	11.7	10.2
Exports, US$ bn	42	44	68	83	91	89	75	76	106
Imports, US$ bn	35	27	51	63	68	72	58	40	45
Current balance, US$ bn	4	6	8	7	11	2	1	25	46
Federal budget as a % of GDP									
Revenues	16.6	13.7	11.8	12.9	12.5	9.8	9.0	13.4	16.2
Expenditures	27.0	20.2	23.2	18.6	15.8	16.6	13.9	15.0	13.7
Balance	– 10.4	– 6.5	– 11.4	– 5.4	– 7.9	– 6.7	– 4.9	– 1.7	2.5
Primary balance	– 9.7	– 4.6	– 9.4	– 2.3	– 2.0	– 2.2	– 1.0	2.1	4.9
Foreign investment, US$ Bn				3.0	7.0	12.3	11.8	9.6	11.0
of which, FDI, US$ Bn				2.0	2.4	5.3	3.4	4.3	4.4

Source: OECD.

seen in this context. The move to cut off non-payers gained momentum in 2000, with impressive results. Payments in the gas sector reached 78% of sales (71% in cash), up from 66% in 1999 (19% in cash). A similar trend occurred in the electricity sector. Tariff reform to ensure that all costs are covered still remains to be accomplished.

The Russian economy expanded strongly in 2000, with preliminary estimates of annual GDP growth at over 8% and in fixed capital investment at 18%. Increases in output were broadly based, while investment concentrated in the energy and transportation sectors. Just as in 1997, mainly external forces have fuelled growth since the financial crisis of 1998. Estimates of Russia's current-account surplus in 2000 exceed $45 billion, compared with $25 billion in 1999 and only $700 million in 1998. Leading indicators and business expectations since late 2000, however, have pointed to a possible economic slowdown, with GDP growth of between three and four per cent. In the current year, many manufacturing firms have been affected by relative increases in domestic energy and transportation prices. Medium to longer-term prospects depend on further progress in implementing reforms in energy pricing, as well as legal and fiscal reform.

Major Problems Continue

The *Main Provisions of the Russian Energy Strategy to 2020* (*"Main Provisions"*), approved by the Russian Government in November 2000, provides a useful guide to current energy-policy thinking and the outlook for the next 20 years.[2] It lists the following problems hampering the energy sector and needing resolution if it is to support general economic growth and reform.

2. *The Main Provisions of the Energy Strategy of the Russian Federation to 2020*, November 2000, is available in Russian on the Russian Ministry of Energy website (http://www.mte.gov.ru) and in English on the IEA website (www.iea.org).

The Highly Depreciated State of Energy-sector Assets

The poor financial state of Russian energy companies in the 1990s limited investment to maintain or renew assets and led to the highly depreciated state of energy-sector assets (Table 2.2). As energy demand increases, adequate investment for maintenance and capacity expansion must be procured.

Table 2.2

Depreciation of Russian Energy Sector Assets (%)

	1995	1996	1997	1998
Electricity	58	58	61	64
Oil production	51	53	56	59
Oil refining	75	74	79	81
Natural gas	59	62	67	70
Coal	52	57	58	60

Source: "Energy Strategy of the Russian Federation to 2020" (MinEnergo, 2001).

Reserve Replacement Not Keeping Pace with Production of Oil and Gas

The 1990s saw a considerable depletion of Russia's oil and gas reserves due to a sharp decline in exploration activity and expenditures, which in turn was linked to the unattractive investment environment. This trend was noted as early as the 1980s, but at that time its impact was offset by higher spending on exploration despite the decline in the cost-effectiveness of additional exploration efforts. In the 1990s, this trend continued and coincided with a drastic investment cut, including that in geological exploration. Since 1994, new oil reserves have failed to offset oil production (the trend from 1996 to 2000 is shown in Table 2.3 below). New field discoveries are increasingly smaller not only in the developed, but also in new, exploration areas. Furthermore, a growing portion of remaining reserves falls into the "difficult-to-recover" category (55-60% currently), while over 70% of reserves now being operated yield such low flow rates that their development is only marginally commercial. This trend was almost reversed in 2000, driven mainly by the higher international oil price level. Natural gas reserves have declined somewhat during the 1990s, as reduced investment in exploration has meant that reserve additions have not kept pace with production. However, with just under one-third of world proven gas reserves, on conservative estimates of proven and probable reserves, Russian natural gas production could be maintained for more than 40 years at 1999 levels.

Table 2.3

Annual Reserve Replacement, 1996 to 2000

	1996	1997	1998	1999	2000
Oil and oil condensate					
Reserve additions (Mln t)	216.7	276	232	199	295
of production	72%	92%	77%	65%	91%
Natural gas					
Reserve additions (bcm)	180	398.5	338	210	450
of production	30%	70%	22%	35%	77%
Coal					
Reserve additions (Mln t)	590.3	255	252	250	–
of production	229%	104%	109%	100%	–

Source: "Energy Strategy of the Russian Federation to 2020" (MinEnergo, 2001).

Energy Intensity per Unit of GDP Increasing Despite Energy-efficiency Policy Initiatives

Economic restructuring, combined with economic downturn has led to reduced energy efficiency. In 1999, the energy intensity of the Russian economy was over three times higher than the average for OECD countries. Low domestic energy prices are a key problem in the Russian energy sector, limiting its ability to finance itself, to attract investment or to promote efficient energy use. Oil and coal prices were liberalised in 1992, but electricity and natural gas prices remained regulated. This led to what Russian energy experts consider a "too high" dependence on natural gas and a drop in the competitiveness of coal as an input fuel for electricity. With electricity and heat prices increasing much less than inflation during the 1990s, efforts to improve energy efficiency failed. Use of space heating and domestic hot water is about 50 per cent higher in Russia than in OECD countries. Manufacturing energy use per unit of output is up to twice as high as in western European countries.

Investment Needs

Economic growth since the crisis of August 1998 has placed increased pressure on the energy sector to meet rising energy demand. The Russian Energy Strategy to 2020 estimates of investment needs for energy supply and transportation range from $480 billion to $600 billion for the next two decades. The strategy distinguishes between the needs for traditional and non-traditional fuels and heat, as well as investments needed to realise its energy efficiency goals. Total investment needs, including this latter category, range from $550 to $700 billion. Table 2.4 provides fixed estimates by sub-sector and sub-period to 2020. This heightens the importance of establishing a stable and competitive investment environment to encourage loan financing, portfolio investment, joint ventures and private direct investment, both domestic and foreign. To put these investment needs into perspective, annual energy sector investments from 2001 to 2005 will need to be almost double those made in 2000. Furthermore, *cumulative* foreign direct investment in Russia over the period from 1995 to 2000 is assessed at about $22 billion. It is estimated that this represents about 20% of the overall capital flight from the country over the same period. Foreign direct investment in China over the same period was about $40 billion per year.

THE INVESTMENT CLIMATE

Despite announcements in late 2001 by investors in both the Sakhalin-1 and Sakhalin-2 PSAs pledging to invest a combined $20 Billion over the next seven to eight year period, Russia is still considered a difficult business environment for investors. Many elements of the legal framework lack consistency and are subject to arbitrary and discretionary implementation. Although work is progressing on establishing a sound fiscal framework through passage and implementation of the Tax Code, a stable and competitive tax regime is not yet in place. Concerns of investors have turned increasingly to non-legislative aspects of the Russian investment climate. The judiciary's dependence on the executive branch of government and private interests remains a key issue. Rights of creditors, shareholders and contracting parties have been violated. Opaque energy pricing – especially for electricity and heat – has kept prices too low for the sector to attract investment. Such a situation can be sustainable in the short term, especially if

Table 2.4 Outlook for Investment Needs in the Russian Energy Sector (Billions of US$)

	1999	2000	2001-2005	2006-2010	2011-2015	2016-2020	Total
Oil	2.3	5.9	28-32	34-43	43-58	55-64	159-197
Production	1.6	4.7	19-21	23-31	31-44	41-48	115-145
Refinery	0.2	0.6	2	3	3	3-4	10-12
Transport	0.3	0.7	5-6	5	5-6	6	20-22
Natural gas	3.1	3.6	34-35	37-39	43-45	51-53	164-171
Production	–	1.0	12-13	17	19	23-24	71-73
Transport	–	2.2	18	17-18	20-21	22-23	76-80
Storage	–	0.4	3-4	4	4-5	6	17-19
Coal	0.3	0.4	2.3	4.5	5.0	6.2	18
Electricity	1.3	1.6	18-19	25-42	44-69	61-87	147-217
Nuclear	0.25	0.35	4-5	6-9	6-11	7-9	23-34
Hydro	–	0.34	3	5	5-6	6-8	19-21
Thermal	–	0.5	7	8-19	24-38	36-54	75-118
Transmission network	–	0.4	4	6-9	9-14	12-17	30-43
Total investment needs (supply & transportation)	7.0	11.5	82-88	98-128	133-177	170-209	484-602
Renewables	0.01	0.02	0.2-0.3	0.6-0.9	0.9-1.3	1.1-1.9	3-4
Heat	0.23	0.45	4-5	5-6	6-7	7-8	23-25
Energy efficiency	0.12	0.21	3-5	6-14	11-22	19-29	39-70
Total energy sector needs	7.4	12.2	89-98	110-148	152-207	198-248	548-701

Source: "Energy Strategy of the Russian Federation to 2020" (MinEnergo, 2001).

energy demand is decreasing as it did in the 1993-1998 period. But in a period of economic growth and increasing energy demand, improvement in these areas is critical for investment to be attracted to meet growing energy needs.

Corruption

The Russian Federation entered the transition period of the 1990s with the legacy of a centralised "control culture" pervasive within public administration. The inadequate separation of private and public interests, which characterised the 1990s transition period in Russia is a key element underlying administrative corruption. The World Bank notes, "In countries where national wealth is highly concentrated in a few productive assets, there are significant risks that powerful interests will seek to gain control over them and invest some portion of their 'windfall gains' to capture state institutions in an effort to sustain and strengthen their positions." "State capture," of considerable concern in the Russian energy sector, involves "the actions of individuals, groups, or firms both in the public or private sectors to influence the formation of laws, regulations, decrees and other government policies to their own advantage as a result of the illicit and non-transparent provision of private benefits to public officials".

The new Putin government has indicated that limiting the influence of key sectoral lobbies, especially in the natural-resources and banking sectors, is crucial to structural reform.[3] The Federal Audit Chamber has powers to investigate individual companies, reporting to the parliament and the President. In early 2001, the Anti-Corruption

3. European Bank for Reconstruction and Development (2000), "Strategy for the Russian Federation", London, October 2000.

Committee within the Duma began work on a draft Anti-Corruption Law. This, as well as the initiative to combat bribery, formed part of the Structural Reform Program promulgated in July 2000.

Tentative measures addressing some of the root causes eroding the independence of the judiciary have been implemented as part of efforts to consolidate federal control over the regions. Under the new federal system, the salaries of judges will increase and be paid out of the federal budget. Previously, judges depended on local budgets for their salaries, court buildings and other facilities, an arrangement, which led to conflicts of interest with regional authorities. New laws also provide that the judiciary and regional authorities report to presidential officials, each representing the seven new "federal districts" and charged with ensuring the implementation of federal laws in their regions.

►►► ***Initiatives to combat corruption and bribery are encouraging and should continue.*** *The government objectives basing public administration on merit, transparency and accountability are important goals. They need to be buttressed by legal regulation and encouraged by the removal of opaque rules allowing discretionary implementation. Linkages between the private and public sectors need exposure.*

Corporate Practices and Enforcement of the Rule of Law

Legal uncertainty in the enforcement of commercial law has discouraged investment in Russia. In the wake of the 1998 financial crisis, international lending organizations and foreign companies made improvements in corporate transparency and accounting practices a condition for loans. Changes in bank supervision, bankruptcy procedures and the step-by-step transformation of Russian accounting towards international accounting standards were agreed in principle between the International Monetary Fund and the Russian government in late 1999. The proposal that the Russian government require joint stock companies to conduct financial reporting according to International Accounting Standards is an important first step. It is encouraging to see companies such as Lukoil, Russia's largest oil company, and Yukos beginning to publish financial statements prepared according to GAAP accounting standards.

►►► ***Increased participation by Russian companies in international financial markets, particularly in debt or equity schemes, requires compliance with internationally recognised accounting standards.***

Monitoring the identity of shareholders and establishing clear rules for mergers and acquisitions are necessary to prevent abusive insider dealing. Further clarification of procedures and timing should enable investors to uncover illicit dealings early on. More complex legal mechanisms may be required to detect sophisticated financial vehicles, such as "overnight" shell companies. Recent trends in the government's restructuring program in electricity and the state railways are encouraging. RAO UES has presented a reform program with a heavy emphasis on improving commercial practices.[4] The government passed a resolution in 1999 requiring the publication by June 2000 of quarterly reports to the public as well as to the Ministry of Energy by Gazprom,

4. RAO UES (2000), "Program to upgrade corporate governance in RAO UES in 2000-2001and during the period of preparation of the restructuring of RAO UES; "Program for higher efficiency and further transformations in the electricity sector of the Russian Federation" approved in 1998.

RAO UES and Transneft, in accordance with International Accounting Standards.[5] The Ministry in turn must prepare reports to the Government on the procedure used by companies and on the company results.

►►► ***Disclosure of corporate relationships, shareholdings, ownership structures, voting rights and the identity of management is essential to enhance transparency and build investor confidence in the private sector. It is also a crucial precondition for the effective regulation of natural monopolies, competition law and the implementation of restructuring policy by state authorities.***

Minority Shareholders' Rights

Providing legal remedies for the violation of minority shareholders' rights is an important element in enhancing overall investor confidence. Despite some government efforts to improve the legislative and regulatory framework, abuse of these rights remains a major issue, especially for foreign investors. Such abuse was alleged recently in the Russian oil and gas sector in relations between a parent company and its subsidiaries. The methods said to be used included stripping profitable subsidiary assets by transferring them to other units controlled by the holding company's management and diluting equity value by selling additional shares at below market price. Russian Company Law allows minority shareholders to appeal against resolutions adopted at annual general meetings and to seek annulment of major transactions including those involving conflicts of interest. Shareholders holding at least 1% of a company's stock can also file suit on behalf of the company against its directors. Yet many practices unfavourable to minority shareholders still exist. The duties of management and directors are poorly defined. Enforcement by the courts remains problematic.

The 1999 Law on the Protection of the Rights of Investors is a further effort to provide guarantees to investors and regulatory powers to the Federal Commission for the Securities Market. It empowers the commission to bring lawsuits and initiate court proceedings on behalf of individual shareholders, of the state or of shareholders jointly when they claim that their rights have been violated. It is unclear whether the commission has adequate independence and resources to undertake these new tasks. Therefore, more radical measures have been proposed to alter the whole legal basis upon which enterprises or joint stock companies are restructured.

►►► ***A balance is needed between protection from undue infringement of property rights and avoiding congestion of the legal system by mischievous claims of minority shareholders.*** *In general, "piercing the corporate veil" and attaching direct liability for damage to individual directors and controlling shareholders are useful approaches in building a climate of individual responsibility.*

Bankruptcy and Creditor Rights

The 1998 Federal Law on Bankruptcy, the 1999 Law on Insolvency of Credit Organisations and the Law on Restructuring Credit Organisations created a new market-oriented framework for enforcing bankruptcy procedures. These laws substituted independent bodies of experts for judges as bankruptcy arbiters. They provided for the appointment of external management during the bankruptcy process. A subsequent presidential decree allowed a debtor's property to be seized in lieu of payment to

5. Government of the Russian Federation (1999), Resolution No. 829, 19 July 1999.

creditors. Companies which were unable to pay a defined minimum debt over three months thereby became subject to the control of an independent body. Punitive sanctions, such as personal financial liability or dismissal, may be applied to managers who discriminate among creditors, who claim bankruptcy falsely or who become bankrupt intentionally or by wilful mismanagement.

Inconsistent actions by liquidators and courts indicate that the bankruptcy mechanism remains subject to lobbying pressure and political influences. There are examples of bankruptcy being used in struggles between large companies and political actors and of its avoidance or delay by regional authorities to protect their friends. Steps to address this issue include the recent adoption of the Order "On Supervision of the Activity of Arbitrage Administrators" by the Federal Service for Insolvency and Financial Rehabilitation. The order grants any person participating in a bankruptcy procedure the right to inspect the bankruptcy administrators' activity and provides for the revocation of the licenses of administrators whose actions prove to be illegal.[6] Another frequent complaint is that minority shareholders are not heard or allowed to vote in negotiations on reorganisation as an alternative to liquidation. Other concerns relate to the priority of creditors' rights. Currently, all debts to the state and to employees, are to be paid before debts contracted in the course of normal business.

►►► ***Further procedural rules are required to ensure the speed and predictability of the bankruptcy process.*** *A refinement of the triggering mechanism for bankruptcy procedures under the Law on Bankruptcy of 1998 could aid in shielding companies from unjustified bankruptcy claims. Clarification is needed to distinguish between procedures for a company's liquidation and reorganisation. Principles for the participation of the state in bankruptcy proceedings also need to be more clearly elaborated.*

Non-Payments and Non-Cash Payments[7]

During the 1990s, the non-payment problem severely weakened Russia's energy utilities (gas, electricity and heat) through loss of receipts. So did various non-cash forms of discounted payment, such as offsets, barter and discounted promissory notes. Under offsets, customer debt to a utility is set off at the end of the year against the debt of the utility to the customer or its owner, usually the central or regional government, which is owed profits or excise tax. More complex three-way or four-way offsets are possible. Barter can also be a simple exchange transaction, but usually the good accepted by the utility in payment is valued at well above its market price, the transactions involve more than two parties and brokers are involved. Promissory notes, called *veksels,* may also be traded, often at deep discounts to face value. Both barter and *veksels* are means of selling gas or electricity to selected customers at discounts to regulated prices.

By 1994, non-payments to the electricity system had built up to 85% of turnover, and 56% of gas delivered to Russian consumers had not been paid for. The worst offenders were the power generators (45% of the total) and State-owned enterprises, which believed themselves immune from disconnection of gas supplies. Overdue payments for exports of natural gas (primarily to Ukraine) exceeded even those of the

6. The European Bank for Reconstruction and Development (2000), *Strategy for the Russian Federation*, London, October, p. 40.
7. Energy Charter Secretariat (2000), *Recommendations on Problems of Non-payment*, endorsed by The Energy Charter Conference on 7 December 2000, Brussels.

generators. More recently, non-payment has been overtaken in revenue erosion by the discounts implicit in barter and other non-cash payments. A World Bank study estimates that the cost of these practices to the energy utilities in the first half of the 1990s was about as high as that of payment arrears. By 1997, the cost of non-cash payment is estimated to have climbed to $US 6.7 billion. In 1998, Gazprom received cash for only 15% of its sales, and the power utilities for only 20%. Significant improvement occurred in tackling the non-payment issue in 1999-2000. Efforts became increasingly focussed after President Putin advertised his intention to get rid of the problem. The Budget Code, effective from 1 January 2000, explicitly banned non-cash transactions at all levels of government. Payment in kind and *veksels* have also been forbidden as payments for electricity. Middlemen have largely been by-passed. The Putin administration has imposed hard budget constraints on Federal agencies and encouraged regional governments to do likewise.

►►► ***Progress in tackling the non-payments problem is encouraging and needs to continue.*** *Government should set the example by ensuring that its federal and regional agencies pay their energy bills on time. Because much of the pressure to accept non-cash payments is applied at the regional level, headquarters of the larger companies should agree progressive regional targets for increasing cash payments, using their shareholdings and other sources of power to enforce these targets. While the use of debt-for-stock swaps may be understandable from the commercial viewpoint of some larger companies, it may not be desirable in liberalising or opening markets for competition.*[8]

Fiscal Policy and Reform

Taxes in Russia are often said to be too high. The overall "enlarged government tax burden" of the three tiers of government (federal, regional and municipal) stood at about 36 % of GDP in 1999. This was higher then the OECD average of 33%, more than the average of 28% in the transition economies and relatively high for a country of Russia's income level.[9] The numerous exemptions that narrow the tax base, together with poor compliance, and the large number of minor taxes,[10] make the statutory and administrative burden considerably higher than is suggested by a comparison of actual receipts.

A significant step toward strengthening the tax administration and the inter-budgetary allocations of revenues and expenditures (fiscal federalism) was made when Part I of the Tax Code came into effect on 1 January 1999. Part I has administrative provisions regulating relations between taxpayers and the authorities, general provisions structuring the taxing authority of the three tiers of government and substantive definitions and rules for levying certain taxes. Article 4 prohibits executive agencies, including the State Tax Service, from issuing directives that "alter or supplement the legislation on taxes". Furthermore, "all contradictions or ambiguities that cannot be eliminated in legislation on taxes and duties are to be interpreted in favour of the taxpayer".

The Putin government proposed far-reaching tax policy reforms. In August 2000, four chapters (Value-added Tax, Personal Income Tax, Social Tax and Excise Tax) of

8. For more detailed recommendations, see The Energy Charter Secretariat (2000), Recommendations on Reducing Non-payment Problems, Brussels, 17 November 2000.
9. International Monetary Fund (2000), "Russian Federation: Selected Issues", IMF Staff Country Report No. 00/150, November 2000.
10. "There is no single estimate of the number of individual taxes in Russia, but it is in the range of 50 to 100. Part of the uncertainty of this estimate arises because it is difficult to draw the line between mandatory taxes and voluntary or user fees": International Monetary Fund (2000).

Part II of the Tax Code passed into law. Two chapters dealt directly with the operation of oil and gas companies and established new rules for calculating and paying value-added tax and excise taxes on oil, gas and petroleum products. In August 2001, more sections of Part II were passed. Effective 1 January 2002, the corporate-profit tax will drop from 30% to 24%. One new volume-based mineral-production tax will replace several existing ones. This will simplify taxation, but it will not make the tax system more profit-sensitive. A profit-based regime is especially important in the energy sector, where up-front costs are high and payouts are long in coming. Most other countries have a specific tax regime for mineral resources, which takes these facts into account. Over the last five years, momentum has built in Russia in favour of an excess profit tax (EPT), which would be tied to the rate of return of each project. Concerns about transfer pricing and lack of transparency, however, have hampered its introduction. The same concerns are tying up the overall fiscal reform process. Passage and implementation of all parts of Part II of the Tax Code, including the EPT, are essential, if Russia is to attract long-term investments. Furthermore, passage of the Production Sharing Agreement chapter of the Tax Code is one of the key remaining tasks to provide for its efficient implementation.

►►► ***Efforts to shift taxes towards a more profit-based regime are encouraging.*** *To attract long-term investment to the energy sector, a profit-sensitive fiscal system is essential. Continued progress on passage of Part II of the Tax Code is encouraged. To bridge the gap while the Tax Code and investment laws are put in place and tested, the PSA could be used as a mechanism to attract investment.*

Regional Investment and Tax Laws

The Russian Federation consists of 89 territorial "Subjects of the Federation". Until recently, devolution of power to the regions had been one of the hallmarks of the transition from Communism. Using the right to introduce their own economic legislation, a number of regions have adopted local laws and regulations affecting foreign investment. The proliferation of *ad hoc* arrangements and bilateral agreements governing federal-regional relations (40 of them by the end of 1997) led to discord and confusion between federal and regional governments. Regional governments rivalled each other and their federal counterpart in offering incentives to investors, particularly tax incentives. Examples include providing loan guarantees or reducing the profit-tax payable to the municipal budget as calculated under federal law.

In 2000, however, President Putin assigned priority to strengthening the federal administration's power over the regions and to the creation of a more coherent federal system. The Constitutional Court has been instructed to review regional constitutional documents in light of the principle that no region may pass or enforce laws that contradict federal laws or the federal constitution.

Production Sharing Agreements[11]

Foreign investors had looked to Russia's adoption of a federal PSA Law in December 1995 as the key legal mechanism to launch upstream oil-sector investment. When the Law was passed, it fitted uncomfortably within the Russian legal framework, with some provisions contradicting other federal laws. Recent efforts by the government have helped resolve certain issues, particularly in crucial areas of taxation and conflict

11. See Oil Sector Chapter for explanation and details of the PSA mechanism.

with the Subsoil Law of 1995. Two Articles of Part II of the new Tax Code, signed by the president in August 2000, specifically cover the tax relationship between the state and parties to PSAs. Article 178 confirms the rights of PSA operators to certain VAT exemptions or refunds. Article 206 exempts excise payments on minerals and refined products that belong to investors under the terms of the agreements. One of the key tasks necessary to complete the PSA regime and provide for its efficient implementation is passage of the PSA chapter of the Tax Code.

To implement effectively the legislative platform provided by the 1995 Law and 1999 amendments, the government is committed to issuing a package of "normative acts" defining the procedures for entering into PSAs and operating under their terms.[12] The federal government has made efforts to clarify which federal regulatory bodies will be responsible for overseeing the preparation and implementation of PSAs. To streamline implementation, it transferred the responsibility to the Ministry of Economic Development and Trade (MEDT) in February 2001. Since 1997, a special Government Commission headed by a deputy prime minister had co-ordinated PSA issues; the MEDT will now replace it in this function.

►►► ***Investors are hopeful that bureaucratic streamlining will quicken completion of the PSA regime.*** *Bureaucratic streamlining should bring a speeding-up of the decision-making process and passage of the normative acts and the PSA chapter of the Tax Code. Effective decision-making will be necessary to ensure realisation of these major investment projects.*

Protection of Foreign Investment

The Russian Constitution contains no specific provisions on foreign investment. It does, however, assert the supremacy of international obligations over domestic legislation. The Constitution provides that foreign citizens and stateless persons have the same rights and obligations as Russian citizens, except where otherwise provided by federal law or international treaty. The Federal Law on Foreign Investment of 25 June 1999 provides basic guarantees of foreign investor rights and some protection (diluted by a number of conditions and exceptions) against future changes in legislation. Lack of clarity in definitions of some key terms, however, weakens the law's application.

- **Application:** the definition of foreign investors under the Law includes legal entities and individuals, as well as international organisations acting under international agreements and foreign governments. It also applies to "branches" of foreign investors, but not to their subsidiaries or affiliated companies.[13] Specifically excluded are investments in credit organisations, insurance companies and non-commercial organisations "formed for the purpose of socially desirable objectives". These are to be governed by separate laws.
- **Guarantees of Foreign Investment:** Article 4 (1) establishes national treatment for foreign investors – the laws applying to them may not be less favourable than those applicable to Russian investors. Exceptions are permitted to the extent required to protect the constitution, public morals and health, the "lawful interests of others"[14]

12. Ordered by government decree in August 2000. It is not clear whether these normative acts have yet been fully implemented.
13. Article 4(3): "A foreign legal entity's branch set up on the territory of the Russian Federation performs part of the functions or all of the functions of a permanent establishment on behalf of the foreign legal entity that has set it up".
14. It is not clear from the law what this means.

and for defence or state security. The Law allows incentive exemptions in the form of privileges for foreign investors. It guarantees to foreign investors compensation (including damages) and restitution in the event of nationalisation or requisition of their property but, unlike the previous law, does not indicate details of timing, method of determining value, or the currency of compensation.[15]

- **Grandfather clause:** a tax stabilisation clause provides a guarantee against unfavourable amendments to legislation that change the amount of certain taxes and customs duties. However, specific taxes, which are important in the energy sector are excluded from this provision. Moreover, ambiguity exists in the scope of this protection mechanism.
- **Remedies:** Article 5 provides a right to compensation for damages for illegal acts and omissions of any governmental or local authority. It also stipulates that a dispute involving the investment activities of a foreigner in the Russian Federation must be settled in compliance with relevant international treaties or federal laws as provided by those instruments. Such dispute-settlement procedures may exist in bilateral treaties. Importantly, Article 26 of the Energy Charter Treaty allows an investor to submit a dispute with the host state to international arbitration even where the parties themselves have not concluded an arbitration agreement. While the Energy Charter Treaty applies provisionally within the Russian Federation, the Duma has not yet ratified it.

►►► ***Ratification of the Energy Charter Treaty of 1994 should remain a priority.*** *The treaty aims to preserve the sovereign interest of the state in energy supply security while providing a level playing field for investors.*

CLIMATE FOR ENERGY SECTOR RESTRUCTURING

The original restructuring of energy industries involved both the injection of private capital and the introduction of commercial disciplines into state-owned enterprises. The second objective was realised, in a legal sense at least, by the transformation of state enterprises into joint stock companies by the end of 1993. But the desired inflow of investment did not occur.[16] Recent policy documents such *as The Basic Provisions for Structural Reform in the Sphere of Natural Monopolies*,[17] the *Main Provisions* and the *Socio-economic Reform Program*[18] have recognised the importance of other elements if a truly competitive environment in the energy sector is to be created. These include:

- improving third-party access to infrastructure and regulation of the terms for its use;
- a transparent privatisation process;

15. The Federal Law on Foreign Investment 1999 also guarantees the right of:
    - access to various forms of investment,
    - the use and transfer outside the RF of profits and other legally obtained money,
    - export of property, information in documentary form and computer data originally imported by the investor into the RF, without any quotas, licensing or other non-tariff requirements,
    - purchase of securities of Russian commercial organisations and government authorities,
    - participation in privatisations,
    - acquisition of rights to land plots (possibly falling short of ownership which appears to be forbidden by the 1991 Land Code), other natural resources, and other real property.
16. According to the *Main Provisions*, annual investment in the energy sector has dropped threefold.
17. President of the Russian Federation (1997), Edict No. 426 of 28 April.
18. Promulgated on 26 July, 2000.

- rules enforcing protection against the abuse of dominant market positions;
- reduction of barriers to entry;
- removal of cross-subsidies as well as efforts to move towards market-based prices.

Government Policy

The Energy Strategy sees the state as leading the process of reform to a competitive system with prices reflecting world markets. The state will act both through its sovereign powers of legislation and administration and as the owner of large shares in the dominant energy companies. From 1997, reduced tariffs for electricity and gas for residential or agricultural customers were to be eliminated. Also contemplated was the establishment of two-part electricity tariffs throughout the federal market except for customers in Siberia and the East. The strategy does not indicate whether the state will withdraw from its ownership when the reform is completed or whether the dominant companies will be broken up. The plan *does* appear to envisage continuing state intervention in the market. That would occur through tax and other privileges to selected players in the market. The state would also continue financial support for the coal and nuclear industries and for particular projects, such as reducing electricity shortages in the Far East and pilot energy-saving projects.

The *Basic Provisions for Structural Reform in the Sphere of Natural Monopolies* aims at the structural reform of those components of the energy sector defined as natural monopolies under Article 5 of the 1995 *Law on Natural Monopolies*. These include the pipeline transportation of oil, gas and their products, as well as the transmission of electricity and heat. In general, the *Basic Provisions* call for a clearer delineation of areas not falling within natural monopolies and the formation of competitive markets within these spheres. The plan aspires to split the vertical integration of natural monopolies and potentially competitive functions, with the latter to be performed by independent enterprises. This has direct importance to the dominant enterprises in the electricity and gas services, RAO “Unified Energy Systems” (UES) and Gazprom. Clarifying rules for non-discriminatory access to the gas and electricity supply systems will encourage independent producers, who in turn will be required to abide by their licensing obligations to ensure reliable supplies.

The *Socio-Economic Reform Program* announced on 26 July 2000 reiterated many continuing concerns. It called for effective anti-monopoly rules to prevent price fixing and to perfect the structural and financial transparency of the monopoly enterprises. It would create separate structural units in the gas sector and divest itself of them as independent commercial companies. A streamlined tax system would promote investment in new fuel deposits and production facilities. New regulations for production infrastructure would promote competition in natural gas. Among other things, it would secure non-discriminatory access for producers to pipelines.

►►► ***Russia’s recognition that government must create the appropriate context for restructuring is encouraging.*** *Many of the elements are still being translated into practice.*

Anti-Trust Regulation

The effective functioning of competition law, particularly in regulating and restructuring monopoly enterprises, is an important precondition for attracting investment. Commonly identified abuses of monopoly power, however, remain outside regulatory authority. These include the extension of abusive market dominance through mergers and acquisitions. The *Law on the Protection of Competition in the Market for Financial Services* prohibits state officials from performing an entrepreneurial activity while in office. As the OECD points out, however, "The precise legal boundary between direct involvement in entrepreneurial activity and passive ownership interest has yet to be clearly defined, and the activities of family members cannot reasonably be restricted in such a direct fashion".[19]

The role of regulatory authorities in supervising the anti-competitive conduct of natural monopolies remains poorly defined. The Ministry for Anti-Monopoly Policy and Support for Entrepreneurship has general competence in anti-trust matters. "Regulatory authorities" have power to supervise certain transactions involving the agents of natural monopolies under the Law on Natural Monopolies 1995. Such transactions include the acquisition of rights to own or use fixed assets, capital investments and the sale or lease of fixed assets with values exceeding 10% of balance-sheet capital.[20] The acquisition of more than 10% percent of the votes in a natural monopoly must be notified to the state.[21] The same obligation applies to acquisitions by natural monopoly agents of share capital in other economic entities.

►►► ***The role of the Anti-Monopoly Ministry in supervising the anti-competitive conduct of natural monopolies in the energy sector needs strengthening.*** *Accurate information on the stock holdings of the agents of natural monopolies and on their relationships with other companies or individuals is an important precondition for containing the abuse of market dominance.*

19. *The Investment Environment in the Russian Federation: Laws, Policies and Institutions*, OECD (2001).
20. Article 7.2.
21. Article 7.4.

3. ENERGY DEMAND AND SUPPLY IN RUSSIA

EXECUTIVE SUMMARY

Energy Demand and Future Trends

The 1995 and 2000 Energy Strategies were drafted within very different macroeconomic contexts. In 1995, Russia had experienced its fifth consecutive year of negative GDP growth, a decline that was viewed as both a damper on energy reforms and a "blessing" that facilitated the task of supplying the country with energy. In contrast, the Strategy to 2020 is set within the growth period that began after the August 1998 financial crisis. The *Main Provisions of the Russian Energy Strategy to 2020* aim to match the energy demand of an economy with annual GDP growth averaging 5% to 6%. The energy sector may not, however, be able to fill these increasing needs. Thus, as in the past, the Strategy continues to emphasise improvements in energy efficiency and the reform of energy pricing. Realising these goals has become ever more critical.

Energy Supply and Future Trends

The *Main Provisions* project energy supply to 2020 based on a major change in the energy policy outlook. This change grows out of a perceived energy-security risk from Russia's heavy dependence on natural gas. The strategy envisages a change in the fuel mix such that the share of natural gas in TPES will decrease from about 50% in the 1990s to 42%-45% in 2020. In its place, coal will gain share, from 16% in 1998 to 22% in 2010 and 21%-23% in 2020. Nuclear energy will rise to 6% in 2020 from its current 5%, whereas oil's share will remain practically unchanged. Estimated energy-sector investment needed during 2001-2020 ranges from $550 billion to $700 billion.

The Regional Energy Demand and Supply Outlook

Russia's vast expanse makes it important to consider its energy balance from a regional perspective. The energy sector faces a key disadvantage because the resource-rich areas of Siberia lie far from both the centres of population and industry and from export points. Energy resources must move great distances from producing to consuming regions, mainly by pipeline and rail. Any change in the energy balance, especially increased coal use, will therefore have major ramifications for the transportation system. In 2000-2020 the European part of Russia is expected to increase its dependence on other regions for supplies of coal, gas and oil, even as its nuclear power generation capacity increases. Western Siberia will remain the major domestic supplier of oil, gas and coal, while Eastern Siberia and the Far East will become net exporters. With the projected start-up of the Shtockman field, the Northern region should swing from net imports of natural gas to net exports.

The IEA's World Energy Outlook[22] Projections for Russian Energy Demand and Supply

In its World Energy Outlook 2000 (WEO), the IEA provides a detailed model of Russia, separate from the rest of the FSU. The model is subject to some uncertainty, mainly about the pace and stability of economic growth and the investment required to meet expected growth in energy demand. The *WEO* assumes more moderate Russian GDP growth at 2.9% and improvements in energy intensity (1.4%) than do the *Main Provisions*. Its demand outlook assumes that consumers will become more sensitive to energy price changes, as more elements of a market economy emerge. Assuming a sustained economic recovery in Russia, the *WEO* projects natural gas to continue playing a dominant role in the Russian TPES.

ENERGY DEMAND AND FUTURE TRENDS

The Energy Strategy of the Russian Federation to 2020 and its *Main Provisions* are based on two scenarios:

- the "optimistic" or "favourable" scenario, where economic, fiscal and price reforms are undertaken effectively and efficiently on the domestic front and there are no major perturbations on international energy markets or in the growth of external markets;
- the "pessimistic" or "not favourable" scenario, where problems arise on the domestic or international front.

The optimistic scenario matches the energy needs of an economy with annual GDP growth averaging 5%-6% to catch up to European standards of living. In this scenario, Russian GDP in 2020 is 3 to 3.15 times higher than in 1998. The pessimistic scenario assumes annual GDP growth rates of only 2.5% to 3.5% out to 2020. In either case, if the energy sector is to keep pace, it will have to make large improvements in energy efficiency and reform energy pricing.

Energy Demand and Economic Growth

In 1999, total energy consumption amounted to 603 million tonnes of oil equivalent, down 31% from 868 Mtoe in 1990. The share of natural gas in TPES increased from 42% to 52% over the same 9-year period. This reflected the "gas pause", the period when the share of natural gas was expected to increase while investments in the coal and nuclear sectors prepared them to take off after 2010. As the share of natural gas increased, the share of oil and oil products in TPES dropped from 30% in 1990 to 21% in 1999 while the share of coal in TPES dropped from 21% to 18%. The shares of hydro-electricity and nuclear energy remained relatively constant during the period at 2% and 4%-5% of TPES (Table 3.1).

In 1999, total final consumption amounted to 410 million tonnes of oil equivalent, down 38% from 657 Mtoe in 1990. The share of natural gas in TPES increased from 22% to 28% over this 9-year period, while the share of coal, oil and oil products dropped from 8% to 5% and from 24% to 21%, respectively. The share of heat and electricity remained constant at about 33% to 34% and 11% to 12%, respectively (Table 3.2).

22. This description of the projections for Russian energy demand and supply is taken from IEA, *World Energy Outlook 2000*, Paris.

Table 3.1 Breakdown of Total Primary Energy Supply, 1990-1999

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
					in Mtoe					
Total Supply (TPES)	**868**	**831**	**789**	**746**	**652**	**628**	**617**	**595**	**581**	**603**
Natural gas	367	374	364	356	328	317	318	312	311	315
Oil & oil products	262	251	235	200	151	147	132	130	124	127
Coal	182	149	132	133	125	117	119	107	101	109
Nuclear	31	32	32	31	26	26	29	29	28	32
Hydro	14	14	15	15	15	15	13	14	14	14
Combustible renewables	12	11	12	12	9	9	7	7	6	8
					Shares (%)					
Natural gas	42.3	45.0	46.1	47.7	50.3	50.5	51.5	52.4	53.5	52.2
Oil & oil products	30.2	30.2	29.8	26.8	23.2	23.4	21.4	21.8	21.3	21.1
Coal	21.0	17.9	16.7	17.8	19.2	18.6	19.3	18.0	17.4	18.1
Nuclear	3.6	3.9	4.1	4.2	4.0	4.1	4.7	4.9	4.8	5.3
Hydro	1.6	1.7	1.9	2.0	2.3	2.4	2.1	2.4	2.4	2.3
Combustible renewables	1.4	1.3	1.5	1.6	1.4	1.4	1.1	1.2	1.0	1.3

Note: TPES in the graph does not include electricity produced from thermal plants.
Source: 1990-1991 IEA estimates; 1992-1999 IEA statistics based on IEA methodology.

Table 3.2 Total Final Consumption by Fuel, 1990-1999

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
					in Mtoe					
TFC	**657**	**635**	**587**	**565**	**486**	**465**	**419**	**402**	**394**	**410**
Natural gas	143	140	136	142	124	118	114	109	112	115
Oil & oil products	155	161	140	119	92	90	84	84	76	85
Coal	55	49	30	30	24	28	23	18	18	20
Heat	224	208	208	205	185	172	143	137	136	136
Electricity	71	70	65	61	55	53	52	51	50	51
Combustible renewables	8	8	8	8	5	4	4	4	3	4
					Shares (%)					
Natural gas	21.8	22.0	23.2	25.1	25.5	25.4	27.2	27.1	28.4	28.0
Oil & oil products	23.6	25.4	23.9	21.1	18.9	19.4	20.0	20.9	19.3	20.7
Coal	8.4	7.7	5.1	5.3	4.9	6.0	5.5	4.5	4.6	4.9
Heat	34.1	32.8	35.4	36.3	38.1	37.0	34.1	34.1	34.5	33.2
Electricity	10.8	11.0	11.1	10.8	11.3	11.4	12.4	12.7	12.7	12.4
Combustible renewables	1.2	1.3	1.4	1.4	1.0	0.9	1.0	1.0	0.8	1.0

Source: 1990-1991 IEA estimates; 1992-1999 IEA statistics.

Total final consumption (TFC) by sector has remained relatively constant over the 1990's. The share of the industry sector in TFC dropped slightly from 38% in 1990 to 33% in 1999, while the residential and transport sectors' share increased from 30% to 33% and 18% to 20%, respectively (Table 3.3). In comparison to OECD countries, Russia's sectoral breakdown shows a much higher share of TFC consumed for the residential sector and a much lower share for transport. In 1999, TFC by sector in the OECD was 30% for the industry sector, 34% for the transport sector, 19% for the residential sector.

Table 3.3 Total Final Consumption by Sector, 1990-1999

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
					in Mtoe					
TFC	**657**	**635**	**587**	**565**	**486**	**465**	**419**	**402**	**394**	**410**
Industry	250	242	223	215	170	167	144	139	131	138
Residential	198	191	177	170	156	146	135	134	132	136
Transport	116	112	104	100	88	82	78	72	82	82
Other	93	90	83	80	71	69	63	57	50	54
					Shares (%)					
Industry	38.1	38.1	38.0	38.1	35.0	35.9	34.4	34.6	33.2	33.7
Residential	30.1	30.1	30.2	30.1	32.1	31.4	32.2	33.3	33.5	33.2
Transport	17.7	17.6	17.7	17.7	18.1	17.6	18.6	17.9	20.8	20.0
Other	14.2	14.2	14.1	14.2	14.6	14.8	15.0	14.2	12.7	13.2

** Other includes agriculture, commercial services, non-specified and non-energy use.*
Source: 1990-1991 IEA estimates; 1992-1999 IEA statistics.

IEA statistics show GDP to have dropped almost 30% from 1992 to 1999, so that energy intensity per unit of GDP increased by more than 6%. Official Russian statistics, in Table 3.4 below, show this ratio increasing 16% from 1990 to 2000[23]. A resource-rich country, Russia can meet declining domestic demand for energy in a period of economic downturn. In periods of economic growth like that since 1999, however, improved energy efficiency of the economy becomes one of the major prerequisites for social and economic advance. The *Main Provisions* base the energy supply and demand outlook on matching annual GDP growth of 5% during 2000-2020. However, inefficient energy use combined with difficulty in attracting energy investment will increase the risk that the energy sector could cause a deceleration of economic recovery and growth.

Much of the needed improvement in energy efficiency is assumed to occur naturally. If energy demand were to continue to grow at current rates, TPES in 2020 would reach about 1,867 Mtoe (or 2,670 mtce[24]), almost triple that in 2000. Assuming the natural economic restructuring that occurs as economies grow, however, service industries are projected to gain a much larger share of GDP. The Ministry of Energy assumes that 70% of the reduction in TPES by 2020 would occur through this process. The remaining 30% would result from cost cutting and technological energy-saving measures. The energy sector is estimated to account for approximately 33% of this potential saving, with another 33% to come from other industrial sectors and construction, over 25% from the residential and utility sector, 6%-7% from transportation and 3% from agriculture.

The Ministry estimates that about 20% of these energy-efficiency requirements could be achieved at a cost of $15 per tonne of coal equivalent (at current price levels). The most costly activities, at over $60 per tce, account for approximately 15% of the potential. The implementation of measures in the price range of $15-$60 per tce, which

23. Differences between the IEA and Russian statistics are due to methodological differences in calculating GDP and TPES. Both estimates, however, show energy intensity per unit of GDP increasing, against the trend in OECD countries and the goals set out in the Russian Energy Strategy of 1995.
24. Russian statistics use millions of tonnes of coal equivalent (Mtce) defined as 27.8 Million BTU per ton of coal.

account for the remaining 66%, is estimated to require from $7 billion to $17 billion from 2000 to 2010 and from $25 billion to $50 billion from then to 2020. Apart from specific programs to be elaborated in the Federal Program approved in 2001, "Energy Efficient Economy", the *Main Provisions* cite flexible mechanisms under the Kyoto Protocol, including Joint Implementation and Emissions Trading, as important contributions to meeting these targets.

Table 3.4 Domestic Energy Demand Trends and Outlook

	1990	1995	2000	2005	2010	2015	2020
Electricity, TWh	1,073	841	864	995	1,135	1,315	1,545
Electricity, as a % of 2000	124	97	100	115	131	152	179
Electricity intensity, kWh/$ GDP	1.08	1.37	1.37	1.25	1.06	0.94	0.86
Central heat, million Gcal	2,076	1,634	1,460	1,555	1,640	1,730	1,820
Heat intensity, Gcal/$ GDP	2.10	2.70	2.31	1.95	1.54	1.24	1.01
Fuel Oil, Mln t	114	68	66	73	81	94	109
including:							
Gasoline, Mln t	34	26	24	27	30	36	41
Diesel fuel, Mln t	57	30	31	35	39	45	52
TPES (Mtce)	1,257	930	929	1,000	1,065	1,155	1,265
TPES as a % of 2000	135	100	100	108	115	124	136
Energy intensity, tce/$1,000 GDP	1.27	1.51	1.47	1.26	0.99	0.82	0.70

Source: "Main Provisions of the Energy Strategy of the Russian Federation to 2020", November 2000.

The *Main Provisions* project domestic energy consumption trends to 2020. As presented in Table 3.4, the ratio of energy to GDP drops by 52% from now to 2020 in the optimistic outlook, with a corresponding fall of 37% in electricity intensity. Heat intensity goes down 56% by 2020. The Ministry of Energy portrays this dramatic improvement in energy efficiency as a major precondition for sustainable economic growth and foresees, in its absence, a deceleration of growth due to the energy sector's inability to match increased "inefficient" energy demand.

Energy Demand and Energy Price Reform

The major policy tool to stimulate efficient use of energy is to increase energy prices to ensure that they cover costs. The *Main Provisions* focus on this, and on the realignment of relative energy prices to regain balance in energy demand and the share of fuels in TPES. The main goals of the energy pricing policy over the period to 2020 are to:

- increase energy prices, taking into account the competitiveness of efficient domestic manufacturers;
- realign prices through a substantial increase in natural gas prices, and reflecting the heat characteristics of different energy resources;
- remove the disproportion between crude and fuel-oil prices, and between electricity and heat prices;
- differentiate prices by region to reflect transportation costs;
- differentiate consumer prices (tariffs) to reflect the different costs of services delivered to different groups of consumers (time of day, season, consumption volume, capacity);
- and remove cross subsidies, replacing them by direct payments to certain consumers.

The Energy Strategy assumes that, to remove current inter-fuel price distortions, energy prices will need to increase, especially natural gas and electricity prices. The outlook for natural gas prices is for them to rise two and a half times by 2003 and again by 1.4 times by 2005, such that by 2007 prices will be in equilibrium with European gas prices. A slower increase is assumed to lead to lower gas production, which would lead in turn to the need for measures to adjust to a natural-gas deficit. The year 2001 is seen as the time for decision making on gas prices and their growth rates. Increases in coal prices will match gas price rises, leading to higher electricity and central-heating prices. By 2005, natural gas prices are expected to be 20 percent higher than steam coal. It will eventually cost from 60% to 80% more. The same applies to the investment component of electricity costs. Projected electricity price increases by 2003 will be 60% to 70% and another 60% by 2005. By 2010, electricity will cost from three-and-a-third to three-and-a-half times what it now does.

Energy Exports

In 1992-1998, Russia's net energy exports, mainly of natural gas, crude oil and oil products, with a small portion of coal, increased almost 10%, from 314 Mtoe in 1992 to 345 Mtoe in 1998. This resulted from an increase in exports, from 354 Mtoe to 367 Mtoe, and a decrease in imports, from 40 Mtoe to 22 Mtoe. Natural gas exports increased about 5%, crude oil exports rose 7%, and diesel-fuel exports soared by 85%, from 13 Mt to 24 Mt. Hard-coal exports fell by over 40%, reflecting the restructuring of the coal sector during the period. A similar drop in coal imports left net exports of coal relatively constant at about one Mt in 1992 and two Mt in 1998. Electricity exports dropped by 40%, reflecting the general economic downturn in the CIS countries, which are major export destinations for Russian electricity. Electricity imports fell even more, by about 70%, so that net electricity exports increased about 11%, from 16 GWh to 18 GWh.

The Energy Strategy projections for little or no increase in exports of oil, oil products and coal to 2020 (Table 3.5) does not conform to current trends of rising exports. In 2000 coal exports increased 21%, to 35 Mt. Coal exports are not expected to increase as fast in the near future as in 2000. But, so long as export prices are higher than in the domestic market, export markets will remain extremely attractive to Russian coal producers. Russian crude-oil and oil-product exports increased significantly over the 1999 to 2001 period, stimulated by higher prices. Oil exports from the FSU (over 90% from Russia in 2001) have increased from 3.24 million barrels a day (mbd) in 1998 to 4.32 mbd in 2000 and to average 4.72 mbd over the first three quarters of 2001. With several projects underway to reduce bottlenecks along certain export routes, the outlook for higher exports would seem brighter than indicated in Table 3.5. The outlook for natural gas exports seems in line with contractual requirements to deliver 200 Bcm to European importers under long-term contracts, beginning in 2008, some of which run to 2025. The outlook for electricity exports depends on major investments as well as capacity needs in potential export markets.

ENERGY SUPPLY AND FUTURE TRENDS

Total Energy Supply

A significant shift in thinking has occurred among Russian policy makers on the outlook for the fuel mix to 2020. Whereas the 1995 Energy Strategy promoted natural gas as the lead fuel, the *Main Provisions* provide a new outlook. As late as 1997, wide-scale

Table 3.5 Russian Energy Exports: 1990-2020

	1990	1995	2000	2005	2010	2015	2020
Total, Mtce	**706**	**480**	**554**	**530-575**	**530-600**	**550-600**	**565-585**
Oil & products, Mln t	286	162	188	160-175	155-180	155-170	150-165
Natural gas, Bcm	213	191	217	245-260	245-275	260-280	275-270
Coal, Mln t	30	22	25	14-18	15-20	15-21	18-20
Electricity, TWh	37	19	13	22-25	30-35	35-55	40-75

(pessimistic scenario – optimistic scenario).
Source: "Main Provisions of the Energy Strategy of the Russian Federation to 2020", November 2000.

use of gas to at least 2010 was still considered the only viable policy capable of improving the domestic fuel and energy sector and boosting performance of the entire Russian economy[25]. Gas was a major priority of Russia's 1995 Energy Strategy. Since 1999, however, Russian thinkers have raised increasing concerns over the energy-security risk posed by an excessive dependence on natural gas. Moreover, future development of gas resources will demand increasing investments that will be impossible to raise, given the current low level of domestic gas prices.

Table 3.6 shows the projections for energy supply from 2000 to 2020 as presented in the *Main Provisions*.

Table 3.6 Russian Outlook of Total Production by Fuel from 2000-2020

	2000	2005	2010	2015	2020
Total production, Mtce	**1,417**	**1,420-1,500**	**1,455-1,575**	**1,500-1,660**	**1,525-1,740**
Oil and condensate, Mln t	323	308-327	305-335	305-345	305-360
Natural gas, Bcm	584	580-600	615-655	640-690	660-700
Coal, Mln t	258	270-300	290-335	320-370	340-430
Nuclear energy, TWh	131	155-175	190-205	210-260	235-340
Hydro-energy, TWh	165	165-170	170-177	180-190	190-200
Renewables, Mtce	1	3-4	5-7	8-12	12-20
Total electricity, TWh	876	970-1,020	1,055-1,180	1,135-1,370	1,240-1,620
Refinery throughput, Mt	174	175-185	185-200	190-220	200-225
Heat production, M Gcal	2,060	2,120-2,185	2,200-2,315	2,300-2,470	2,420-2,650

Source: Main Provisions of the Energy Strategy of the Russian Federation to 2020, November 2000.

Ministry of Energy projections of investment needed to realise this ambitious outlook range from $550 billion to $700 billion. The *Main Provisions* project that 80%-90% of the requirements in 2000-2010 can be generated internally, if the planned price and tax reforms are implemented. Loans are expected to cover 25%-30% after 2010. But this assumes the major fiscal, legal, regulatory and pricing reforms required to reduce the investment risks perceived by financial markets and institutions, are achieved.

25. RAO Gazprom (1997), *Strategic Development of the Russian Gas Industry.*

Crude Oil

Crude-oil production peaked in 1988 at close to 600 million tonnes, then plummeted almost 50% in the first half of the 1990's, to stabilise in 1995 at about 300 million tonnes. The Energy Strategy projects annual production growing to around 360 million tonnes in 2020. The pessimistic scenario projections of only 305 million tonnes in 2020 assume low world oil prices and little or no improvement in fiscal and legal reform. This underscores the critical situation faced by the oil sector if longer-term investments are not made. About 100 million tonnes a year from mature West Siberian fields will need to be replaced in the next seven to ten years.

The *Main Provisions* point to the low reserve replacement rates experienced over the last decade and the increasing share of marginal fields,[26] estimated at 55%-60% of the total in 2000. Although West Siberia and the Urals-Volga Region are likely to remain the main oil-producing areas, many of their fields are in mature phases. By 2020, 15-20% of projected Russian oil production will come from the East of Russia. This will compensate for depletion at Western Siberian fields and its expected share dropping from 68% to 55%-58%. Other areas have considerably lower resource potential, because of their higher production costs. The recoverable oil and gas reserves of the European North, East Siberia and the Far East lie in difficult areas. The resource potential of the newer provinces is considerably lower and more costly than that of older fields. These facts highlight the importance of establishing a comprehensive, clear, and stable legal framework for petroleum licensing and operations, for both Russian and international companies to attract the needed investment.

The oil sector is in much better shape than other parts of the Russian energy complex. Because up to 90% of its expenditures are denominated in roubles, the 1998 devaluation led to a dramatic decrease in its costs. This, together with sustained higher international oil prices beginning in 1999 and on into 2001, has given Russian oil companies more export-earned dollars with increased purchasing power in Russia. Furthermore, many companies used the period of lower oil prices to cut costs and rationalise parts of their operations. Reform of the tax system and effective implementation of legislation, which provides investors long-term guarantees to undertake long lead time, major up-front investments, is essential, to maintain production growth. Streamlining the regulatory process will become increasingly important to investors, as more and more large-scale investments under PSAs enter their implementation stage.

Oil Refining

To satisfy Russian domestic needs and ensure exports, the Energy Strategy envisages an increase in refined oil products to between 220 and 225 Mt/year by 2015-2020 from 169 Mt in 1999. It also calls for a 75% to 80% increase in refinery depth by 2010, rising to 85% by 2020. It envisages the construction of new, highly efficient medium-size refineries in areas with high oil-product consumption, as well as small refineries in remote northern and eastern areas.

Natural Gas

The *Main Provisions* project gas production at 700 Bcm in 2020, a downward revision from earlier projections. Gazprom projections are around 530 Bcm, with the rest coming from increased production by other gas producers and oil companies, which currently account for 10% of output. Over 76% of projected gas production will come from

26. The Russian definition for marginal fields covers those that produce less than 10 t/day.

new fields. In 2000, over 85% of Russian gas came from the West Siberian fields of Medvezhye, Urengoi (Senoman) and Yamburg (Senoman), which have depletion rates of 78%, 57% and 46%, respectively. The main gas-producing area will still be the Nadym-Pur-Tazovsky region of West Siberia, although its share is expected to fall to 60% to 64% by 2020 from the present 87%. The *Main Provisions* project the need to start production in 2006 at the fields in Obskaya and Tazovskaya Guba, Shtockman field on the Barents shelf and, later, the Yamal Peninsula fields. The Shtockman field has development priority over the Yamal fields because its cost estimates are two-thirds that of Yamal's, not to mention the unresolved ecological issues in the development of Yamal. Another large-scale producing district will be the Kovyktinskoye field in the Irkutsk area. The growth of gas production in Eastern Siberia and the Far East will depend primarily on the profitability of gas exports to Asia-Pacific buyers. Finally, the programme for the development of small or marginal fields has regional importance, especially in economically developed European areas.

Coal

Coal production in Russia peaked in 1988 at 425 Mt. It dropped throughout the 1990's and levelled off in 1999 at 235 Mt. Despite the fact that hard and brown coal production has decreased almost 45% over the last decade, the *Main Provisions* project annual coal output as high as 430 Mt by 2020. Lower production in the 1990s resulted from decreasing demand, growing inefficiency in the coal-mining industry and lack of reinvestment in plants and equipment. By 2000, the industry had gone through extensive restructuring and mine closures. Initial results appear positive, with coal production increasing more than 7% in 1999 and more than 3% in 2000 as internal consumption and export demand increased. The plan for higher coal production hedges against possible energy-supply disruption should gas production and nuclear-station commissioning fall short. In line with new Russian views of the energy balance, coal demand is projected to rise to 335 Mt by 2010 and 430 Mt by 2020.

The main producing regions will be in the Kuznets and Kansko-Achinsk basins. The mines of Eastern Siberia, as well as Pechora, Donetsk and Southern Yakutsk will have only regional importance. Increasing the share of open-pit production is projected to continue, with the open-pit share reaching 80%-85% by 2020. After the closure of some 60 Mt of uneconomic mining capacity, construction of new capacity is estimated at about 200 Mt, including 75 Mt in the Kuznetsk Basin, more than 70 Mt in the Kansko-Achinsky basin and 20 Mt in the Far East fields.

Electricity and Heat Generation

The *Main Provisions* project a 34% increase in electricity output by 2010 (to 1,180 TWh) and an 84% increase by 2020 (to 1,620 TWh) under a favourable economic-growth scenario. This case envisions electricity production recovering to pre-1990 levels by 2010. In a lower-growth scenario, production would reach only 1,055 TWh in 2010 and 1,240 TWh in 2020, attaining pre-1990 output only in 2015.

The economic turnaround in 1999 and 2000 triggered a change in policy thinking about electricity. With strong economic growth and increased electricity demand, planners raised doubts about Russia's ability to develop natural-gas reserves. Others stressed concern about the energy-security risk of an excessive dependence on natural gas. Reflecting these concerns, the new Strategy foresees a decrease in the share of natural gas in the fuel mix much sooner than 2010. The *Main Provisions* project gas consumption at power stations to remain unchanged to 2005 and beyond. Absolute levels of gas consumption at power stations will not reach 1990 levels throughout the period to 2020. Instead, power-station coal consumption is projected to increase by 1.5 to 2 times. With electricity generation set to double by 2020, the share of natural gas in the fuel mix for thermal power generation will drop from 60.8% to 50.8%, with coal's share rising from 30.6% to 44.4%.

Nuclear Power

In 2000, nuclear energy of about 21 GW accounted for 15% of Russian electricity production, but nuclear generation supplied over 90% of the increase in electricity demand from 1999 to 2000. Nuclear capacity is projected to grow dramatically, at 35 GW in 2020 in the low-growth scenario and over 50 GW with high growth. The projected share of nuclear power in total electricity generated increases from 15% in 2000 to 21% by 2020.

Priority locations for nuclear stations remain the European and Far East areas as well as the Far North. The Strategy also envisages construction of a number of low-capacity nuclear stations, from one MW to 50 MW, including floating ones, to serve as autonomous sources of decentralised energy supply, especially in isolated areas far-removed from other fuel sources.

Hydro Power

Russia's hydro-electric potential, if fully exploited, could run all Russia's electric stations. Because of the very long lead time and the enormous investments needed to develop these resources, however, the projections show only a modest increase from 160 TWh in 2000 to 170-177 TWh in 2010 and 190-200 TWh in 2020. This forecast assumes that production costs at new hydro stations will not exceed 3.5 to 4 US cents/kWh. Hydro-energy will develop primarily in Siberia and the Far East, providing base-load power for CHP stations there. In European regions, construction of medium-to-peak[27] hydro-stations will continue, primarily in the North Caucasus region. Plans call for completing the Bureiskaya Station in the Far East by 2010, as well as the commissioning of several other hydro stations already under construction in Siberia, the Far East and the North Caucasus. After 2010, a 2 to 3.6 MW station is to be commissioned every five years. The Strategy also envisages commissioning two or three hydro-power stations in the European part of Russia to ensure the reliable performance of RAO UES.

THE REGIONAL ENERGY DEMAND AND SUPPLY OUTLOOK

A key disadvantage of the Russian energy sector is that the resource-rich areas of Western and Eastern Siberia lie far from the centres of population, industry and exports. Energy resources need transportation from producing to consuming regions. Table 3.7 shows regional energy balances in 2000 as deficits or surpluses. A region in deficit produces less than it consumes, whereas one in surplus exports its surplus to deficit regions.

27. Medium-to-peak (as opposed to baseload) means that the power station will run during periods of medium or peak demand. Some hydro stations hold back enough water to operate 40-50% of the time.

Table 3.7 Russia's Regional Thermal Fuel Balance Outlook to 2020

Region Deficit(–) / surplus(+)	Gas (mtce)		Oil (mtce)		Coal (mtce)	
	2000	**2020**	**2000**	**2020**	**2000**	**2020**
North	– 14.2	88.7	7.5	31.6	2.0	– 2.5
Northwest	– 19.7	– 24.0	– 10.8	– 16.8	– 1.4	– 5.1
Central	– 88.2	– 99.9	– 34.0	– 51.0	– 9.2	– 25.5
Volga-Vyatsky	– 20.0	– 23.1	– 10.1	– 15.0	– 2.6	– 9.3
Central-Black soil	– 21.9	– 25.6	– 5.3	– 8.0	– 6.4	– 8.4
Lower-Volga	– 54.1	– 66.6	29.6	– 11.8	– 1.1	– 2.8
North Caucasus	– 31.6	– 38.0	– 8.6	– 19.5	1.9	0.8
Urals	– 58.5	– 78.5	15.3	– 20.1	– 28.9	– 50.0
West Siberia	534.3	491.7	293.2	265.5	45.4	73.6
East Siberia	0	16.5	– 15.0	14.0	5.3	33.5
Far East	0	27.9	– 9.1	21.3	– 0.8	– 4.1

Source: Draft Energy Strategy of the Russian Federation to 2020 (MinEnergo, March 2000).

Table 3.8 TPES and Electricity Supply by Region: 2000 to 2020

Region	**2000**		**2010**		**2020**	
	TPES M tce	**Electricity TWh**	**TPES M tce**	**Electricity TWh**	**TPES M tce**	**Electricity TWh**
European zone	**485**	**434**	**515-550**	**515-570**	**550-660**	**605-800**
• North	51	49	55-59	57-63	58-73	67-90
• North West	40	38	43-46	47-51	47-55	55-67
• Centre	136	127	145-155	152-168	157-193	180-239
• Volgo-Vyatsky	42	40	43-47	47-52	47-56	55-70
• Central Black Soil	45	43	47-50	50-55	47-56	55-70
• Volga	113	89	117-128	106-119	129-155	126-165
• North Caucasus	58	47	63-68	55-63	66-85	66-92
Urals	**168**	**143**	**182-188**	**167-180**	**188-217**	**195-235**
Eastern zone	**277**	**288**	**300-326**	**338-385**	**321-378**	**400-510**
• West Siberia	153	124	163-175	149-170	170-196	175-220
• Eastern Siberia	82	123	90-100	141-160	102-117	165-200
• Far East	42	41	46-51	49-55	50-65	60-90
Russia total	**929**	**865**	**995-1,065**	**1,020-1,135**	**1,060-1,265**	**1,200-1,545**

Source: "Main Provisions of the Energy Strategy of the Russian Federation to 2020", November 2000.

From 2000 to 2020, the European part of Russia will increase its dependence on other regions for supplies of coal, gas and oil, while its nuclear power generation will grow. West Siberia will maintain its importance as a provider of natural resources, increasing its coal share, maintaining its gas position and receding slightly as an oil provider. The Northern region will swing from net imports to net exports of natural gas with the projected start-up of the Shtockman field. East Siberia will have growing importance as a supplier of all natural resources.

Table 3.8 from the *Main Provisions* presents the projections for TPES and electricity supply on a regional basis given the varied productive capacities and natural resource endowments of each region.

Economic growth is assumed to be stronger in the European part of the country than in the Eastern part, because of the European region's industrial concentration. The region's economy is expected to grow at least three times as fast as the energy sector. But energy intensity in the European region is lower then elsewhere, and so the projected growth of energy consumption, especially in 2001-2010 will be below average. In the Eastern parts of Russia, expected economic growth fuelled mainly by domestic and export demand for raw materials, will be much slower. The *Main Provisions* highlight the key issues and areas of development in each region of Russia.

The Northern Region

- Develop onshore and offshore oil and gas resources for export markets;
- improve and develop the electricity supply system using different generating facilities and construction of a new network;
- maintain volumes and inter-regional flows of steam and coking coals;
- gasify the Karelia, Archangelsk and Murmansk Oblasts, and parts of the Komi Republic.

The North-Western Region

- Further develop electricity through deep restructuring, modernisation and the construction of new heat and nuclear plants;
- improve gas-based heat supply and restructure centralised heat supply, primarily in St. Petersburg;
- create a new oil-export terminal on the Baltic Sea;
- promote the energy independence of the Kaliningrad Oblast through the diversification of its heat supply and development of the local energy base.

The Central Region

- Develop generating capacity through modernisation, technical re-equipment, commissioning of combined-cycle plants and the strengthening of electricity connections;
- develop nuclear energy, but if this is to be done, public opinion must be persuaded it is safe;
- overcome the unfavourable ecological situation arising from a high concentration of energy production and energy consumption in densely populated regions.

The Volga-Vyatsky Region

- Rebuild and modernise oil refinery capacity;
- modernise existing electricity capacity.

The Central Black Soil Belt Region

- Develop nuclear energy – virtually the only energy source in the region;
- gasify rural areas.

The Volga Region

- Modernise and develop the oil and gas sectors using the latest domestic and foreign technologies;
- preserve the optimal relations among different energy generating capacities;
- ensure energy transit from eastern regions into the central part of Russia.

The North Caucasus Region

- Further develop the oil-transport and oil-export functions;
- rebuild, modernise and develop local electricity generating capacity, including nuclear power stations, and improve electric connections with neighbouring territories;
- improve secondary oil refining capacity;
- increase the use of hydro-electric resources and exploit the potential for non-traditional renewable energy sources.

The Urals Region

- Pursue large-scale technical re-equipment of electricity and heat facilities;
- increase coal – and nuclear-based energy production;
- modernise, reconstruct and develop oil refineries and oil and gas companies.

The West Siberian Region

- Further develop the oil, gas and coal sectors so as to retain the region's status as the main producer in Russia;
- address the social problems of employees of these industries;
- improve heat and energy supply of the region through the gasification and electrification of the production and residential/utilities sectors;
- address ecological problems in the main oil, gas and coal production regions;
- diversify West Siberian production of oil products through the upgrade or construction of refineries;
- create the North Tyumen, Middle Ob and Kuzbass territorial and production complex.

The East Siberia Region

- Rationalise the structure and location of electricity sources (through the construction of hydro and thermal power plants);
- increase the reliability of electricity and heat supply to ensure an end to shortages in the Republic of Tuva, Buryatya and Chita Oblast;
- form a large new oil and gas base of inter-regional importance based on the hydrocarbon resources of Irkutsk Oblast, Krasnoyarsk Krai and the Sakha Republic (Yakutya);
- increase coal production and use in the Irkutsk Oblast;
- reduce environmental damage;
- widen the use of non-traditional renewable energy sources for northern territories, the Baikal Area and other regions of decentralised electricity supply;
- create the Angaro-Evenkiisky, Kansk-Achinsk, Sayansky and Angaro-Lensky territorial and production complexes.

The Far East Region

- Increase the reliability of heat and electricity supply, which is now prone to outages;
- develop the large oil and gas resources for export markets;
- gasify Sakhalin Oblast and Primorye and Khabarovsk Krai, as well as Kamchatka Oblast;
- improve the region's self sufficiency in locally processed oil products;

- diversify the electricity generating capacity (hydro-and nuclear stations) as well as the fuel balance of CHP stations;
- support energy efficiency and development of non-traditional and renewable energy sources.

THE IEA'S WORLD ENERGY OUTLOOK PROJECTIONS FOR RUSSIAN ENERGY DEMAND AND SUPPLY

The IEA's World Energy Outlook 2000 (WEO) provides a detailed model of Russia, from 2000 to 2020, separate from the rest of the FSU. The model assumes that the pace of reform will accelerate and that GDP will expand faster in the second half of the outlook period, based on solid internal policy changes rather than on the external factors that mainly fuel current growth. Over the long term, the economy will stabilise, with market institutions more firmly established. The non-payment problem in the energy sector will be addressed before the removal of price subsidies. Domestic energy prices, previously very low, will rise to approach international levels. Oil and gas exports will continue, and government revenues from energy exports will rise.

The projections of Russian energy demand presented many statistical and methodological difficulties. The WEO assumed average annual GDP growth of 2.4% a year to 2010 and faster growth thereafter, with the overall average at 2.9% from 1997 to 2020. This outlook is lower than Russian Energy Ministry projections, which assume economic growth of 5% to 6% per year to 2020. If population declines by 0.2% annually over the outlook period (the actual annual decline was slightly less than 0.3% in 1992-1997), per capita GDP is projected almost to double, reaching some $9,500 by 2020 (in 1990 US$ PPP). GDP growth assumptions depend, of course, on accurately measuring the size of the Russian economy. The Russian statistical authority augments recorded GDP by roughly 22% to 25% to try to capture informal or hidden economic activity.[28] Considerable uncertainty surrounds the effect on Russian GDP of the likely contraction of the informal economy.

The WEO indicates that primary energy demand will reach its 1992 level of some 780 Mtoe only towards 2020. TPES will grow by 1.5% per year on average over the outlook period, much slower than the assumed GDP growth of 2.9%. This means improvements in energy intensity of 1.4% per year on average, based mainly on structural changes in the economy and in the energy sector. Russian Ministry of Energy projections are much more optimistic. They assume TPES growth ranging from a low of 0.5% per year to 1.13% per year, much less than the expected GDP growth of 5%. This would mean improvements in energy intensity of 2.8% to 4% per year on average, as the service sector gains in importance with GDP growth.

28. Masakova, Irina (2000), "Estimation of Non-Observed Economy: The Statistical Practices in Russia", State Committee for Statistics of Russia, Moscow.

The IEA's energy projections for Russia are subject to great uncertainty, mainly as to the pace and stability of economic growth and Russia's ability to attract the necessary investments. Despite the difference in GDP growth between the two outlooks, expected improvements in energy efficiency are robust in both.

The Russian Energy Strategy to 2020 projects a 0.5% average annual growth rate in oil production with oil output reaching 6.1 to 6.7 mb/d in 2010 and 6.1 to 7.2 mb/d in 2020. WEO 2000 projects Russian oil production levels to rise to 7.1 mb/d by 2010 and 7.9 mb/d by 2020, for an average annual production increase of about 1.1%. If the strong performance of 2000/2001 is sustained and if the Tax Code and other policy measures are implemented, Russian production and exports could exceed current projections over the next two decades. Russian industry projections are much more bullish than the government outlook[29]. The WEO expects that demand for oil will grow faster than other fuels due to strong growth of the transport sector, with oil's share in TPES expected to gain five percentage points by 2020 to reach 27%. Similarly, the WEO 2000 projects Russia's natural gas production to rise to 850 bcm by 2020, in order to meet domestic needs and satisfy export contracts. This matches earlier Russian outlooks. However, the *Main Provisions* have dropped their forecasts for natural gas production levels to 700 bcm by 2020 in line with the outlook of investment needs and the resulting changed outlook for the evolution of the fuel mix.

Major differences exist between the IEA and Russian outlooks in this respect. Whereas the WEO projects the TPES fuel mix largely to follow current trends, the Russian outlook assumes a shift away from natural gas to coal. The WEO projects natural gas to account for over half of TPES in 2020 and to be the only fuel to reach its 1992 level over the outlook period. The gas share of total electricity generation rises to 61% in 2020 from 42% in 2000. The share of coal in TPES falls from 17% in 1997 to 14% in 2020, despite a slight increase in its share in the electricity input fuel mix, from 17% in 1997 to 18% in 2010, dropping back to 14% by 2020. By contrast, the Russian outlook projects the share of coal in the electricity input fuel mix to increase to 29% by 2020. The WEO projects nuclear power will account for 4% of TPES in 2020 and hydroelectricity for 2%. Nuclear power will decrease its share in total electricity generation from 15% in 2000 to 9% in 2020 and for hydro's share to decrease from 18% to 14%. By contrast, the Russian outlook projects nuclear power to increase its share in total electricity generation to 21% in 2020.

Table 3.9 contrasts the Russian and WEO projections of the electricity fuel mix. Although the outlooks appear quite different at first glance, the major difference between the two is the outlook for natural gas. In its outlook, the IEA places less emphasis on energy security and the risk posed by excessive dependence on natural gas. Russian energy experts consider this is a key factor. In view of Russia's tremendous natural gas reserves, the WEO considers economic factors related to current under-pricing on domestic markets much more significant then the security argument. The, IEA foresees the successful implementation of planned price reforms and successful tackling of the

29. For example, Yukos Chairman and CEO Mikhail Khordokovsky projects a 7% increase in output for 2001 to 6.8 to 7 mb/d and a further consolidation and production growth for the whole Russian industry, with output expected to rise to 8.2 mb/d by 2005 under an acceptable tax regime (Russia in the New Millennium, June 2001).

non-payments problem. If the reforms are successful, the Russian market could surpass export markets in terms of attractiveness, especially in view of transportation costs associated with exports.

Table 3.9 Comparison of WEO and Russian Projections of the Electricity Fuel Mix to 2020

	WEO projections			Russian Energy Strategy projections		
	2000	**2010**	**2020**	**2000**	**2010**	**2020**
Natural gas	42%	47%	61%	42%	39%	34%
Coal	17%	18%	14%	17%	26%	29%
Petroleum products	7%	4%	3%	7%	3%	3%
Hydro-electricity	18%	17%	14%	18%	16%	12%
Nuclear	15%	13%	9%	15%	15%	21%
Other	1%	1%	1%	1%	1%	1%

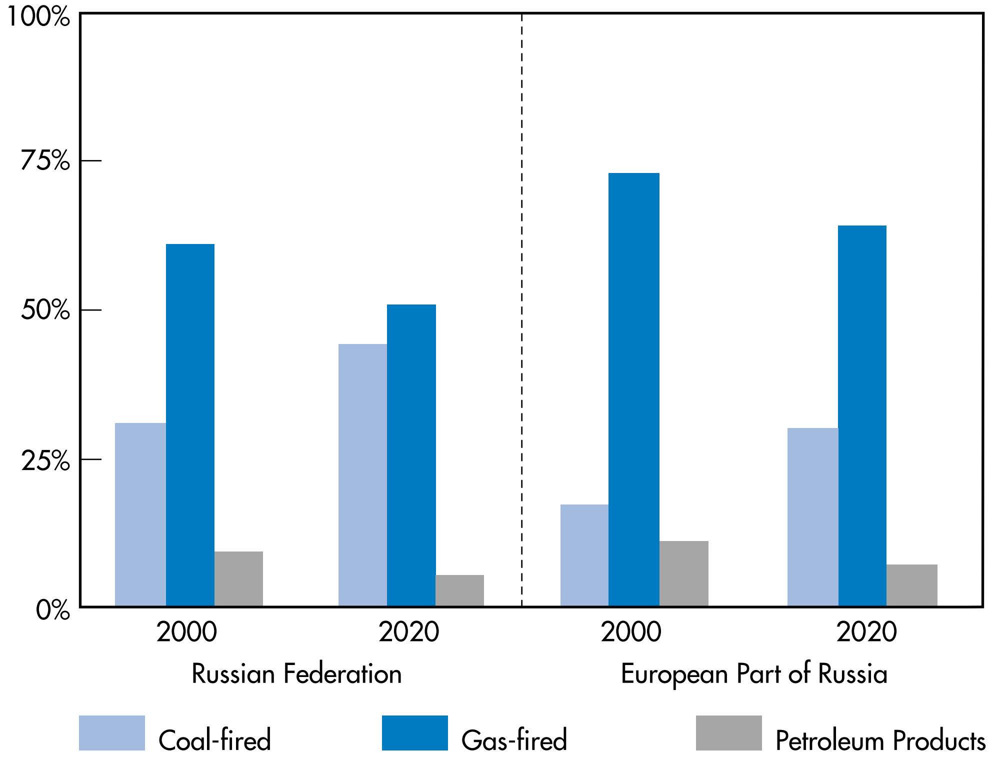
The energy-security risk that concerns Russian energy experts becomes more evident if one looks more closely at the thermal fuel mix for electricity generation, in other words, if one excludes nuclear and hydro generation. Figure 1 shows that natural gas accounted for 61% of thermal heat and electricity generation in Russia in 2000, while coal accounted for only 31% and heavy fuel oil for the remaining 8%. Across Russia, however, the differences in mix are significant, with a high share of natural gas in the European part of Russia, 73% of thermal power generation. In contrast, the share of natural gas was only 3% in Siberia and the Far East. Here, coal is the main fuel, and as one moves farther east hydropower becomes increasingly important. The Russian energy strategy projects a sharp increase in the role of coal in the European part of Russia and consequently in the overall Russian thermal fuel mix. As Figure 1 shows, the projected share of coal in the European part of Russia increases to 30% in 2020, while that of natural gas decreases to 63%. In the outlook for the overall Russian thermal fuel mix, the share of coal increases to 44% of the total in 2020 with matching decreases for natural gas to 51% and for heavy fuel oil to 5%.

The IEA outlook raises questions about the ability of either the coal or nuclear sectors to increase their shares in total electricity to such a large extent over the 2000-2020 period. Factors limiting a dramatic increase in coal production include:[30]

- the need for massive private investment to open new coal mines with state of the art technology;
- coal's true competitiveness as an input fuel for electricity and heat, in a situation where so much infrastructure is already in place for natural-gas use, and at projected inter-fuel prices;
- the difficulty of reforming prices without worsening the non-payments and debt problem;

30. These and similar factors affecting nuclear expansion are discussed in more detail in the sector-specific chapters.

Figure 1 Russian Projections of the Thermal Fuel Mix for Heat and Electricity Generation to 2020 (in percentage)



Source: A. M. Mastepanov, Ministry of Energy of the RF, International Conference, Irkutsk, 2000.

- the infrastructure, capacity and increased unit costs needed to transport much higher volumes of coal across Russia from producing to consuming regions; and
- the environmental implications of increased coal consumption in terms of both local pollution and global warming.

Similarly, factors limiting a dramatic increase in nuclear-generated electricity include:

- the true economic competitiveness of the nuclear power;
- the need for financial resources, especially outside investment;
- the need for a research and development programme to develop new generation plants;
- the need to improve the safety of existing plants;
- the need to increase the financial and human resources of the GosAtomNadzor, the nuclear safety regulator, in order for it to take on all the necessary functions such a program would entail;
- problems connected with the end of the fuel cycle and waste management;
- the importance of public acceptance.

4. OIL SECTOR

EXECUTIVE SUMMARY

Petroleum Industry Structure

The oil sector contributed an estimated 8% of Russia's GDP and 35% of its foreign trade earnings in 2000, and supplied some 20% to 25% of Federal budget revenues. The industry was reorganised in the 1990s into several large vertically integrated companies (VICs), each combining exploration, production, refining, distribution and retailing. Currently, the sector includes eleven large VICs, which accounted for 88% of crude production and 79% of refinery throughput in 2000. Over 100 small independent producers accounted for 3% of crude oil production in 2000. Gazprom accounted for another 3%, joint ventures for 6% and production from Production Sharing Agreements less than 1%. Several of the VICs have been criticised for poor corporate practice, for failing to respect shareholder rights, and for lack of transparency. The underlying legal and regulatory frameworks for the sector are still being established, and those statutes that do exist are badly implemented.

Crude Oil Reserves and Production

Although the government does not publish data on the size and location of Russia's oil reserves, Western sources place them at about 4.5% of world proven reserves. Russia ranks third in the world in oil production behind Saudi Arabia and the US. Production was 323 Mt in 2000, down from a peak of 569 Mt in 1987. The average daily flow per well dropped from 27.6 tonnes in 1980 to 7.1 tonnes in 1999, reflecting the physical maturation of Russian oil fields. Production stabilised in 1995, but was derailed again in 1998 by the collapse in international oil prices and the Russian financial crisis. It recovered again in 1999 under the impetus of high oil prices and a decline in Russian production costs due to the devaluation of the rouble. The *Russian Energy Strategy to 2020* envisions crude-oil production growing slowly over the next two decades to reach 335 Mt in 2010 and 360 Mt in 2020.

Oil Sector Reform and Legislative Framework

Effective oil-sector reform will be a key factor in sustaining Russia's economic recovery. It will be important to establish a comprehensive, clear, and stable legal framework for petroleum licensing and operations, for both Russian and international companies. This will require co-ordination at both the Federal and regional levels. Production-sharing agreements can act as a bridge to attract investment while a legal and tax regime is put in place and confidence in it is built. Russia's current oil taxation regime relies heavily on volume-based revenue and excise taxes at very high combined rates. The current fiscal system offers little incentive to invest in long-term new oil production.

Crude Oil Transportation and Exports

Russia is the world's second-largest oil exporter after Saudi Arabia. In 1988 crude oil exports peaked at 124 Mt and have remained relatively stable, reaching 126 Mt in 2000. With the decline in oil demand in Eastern Europe and the FSU, a large proportion of exports has flowed through a few ports that dispatch crude to international markets.

Major bottlenecks have developed. Projects are underway to build new export terminals in Russia and to increase use of pipelines.

Petroleum Refining and Consumption

The 1990s saw a 45% fall in refinery throughputs to only 163 Mt in 1998. Throughputs recovered in 1999 and 2000, due mainly to administrative limits on crude-oil exports. Due to a lack of sophistication, or "depth" in Russian refineries, excessively high crude runs are needed to meet growing requirements for light products, leaving a large excess of heavy fuel oil that is usually exported. Apparent aggregate consumption of refined products fell by more than half between 1990 and 1998. Buoyed by a stabilising economy and administrative limits on exports, consumption since 1999 seems to have stabilised.

PETROLEUM INDUSTRY STRUCTURE

The Russian oil industry was reorganised in the 1990s into several large vertically integrated companies (VICs), each combining exploration, production, refining, distribution and retailing. There are now eleven large VICs, which collectively accounted for 88.2% of national crude production and 78.8% of refinery throughput in 2000 (Table 4.1). The reorganisation began in 1992-1993 with the establishment of LUKoil, NK Surgutneftegaz, and YUKOS. Initially, a new central body, called Rosneft, held the state's shares in all oil enterprises following their incorporation as joint-stock companies. In 1994, several additional VICs were carved out of Rosneft, including Slavneft, Siberia-Far East Oil Company (Sidanko), Eastern Oil Company (Vostochnaya Neftyanaya Kompaniya or VNK), and Orenburg Oil Company (ONAKO). In 1995, Tyumen Oil Company (TNK) and Siberian Oil Company (Sibneft) were also formed from Rosneft assets. Two major refineries in Moscow and one near Nizhniy Novgorod also emerged as essentially independent companies, becoming the Moscow/Central Fuel Company and the Norsi Oil Company, respectively. Regional companies, including Komi-TEK, Bashneft and Tatneft, were established out of the oil enterprises located on the territories of several autonomous republics.

The new VICs were originally holding companies with only partial stakes in their subsidiaries – typically 51% of voting rights *via* 38% ownership of common shares. A sizeable proportion of equity was usually turned over to employees in the form of non-voting or preferred shares. Most VICs are now in various stages of consolidation into 100% ownership of their subsidiaries. LUKoil was the first to accomplish this. All of its subsidiaries ceased to exist as independent entities on 1 January 1996. Consolidation has also taken the form of mergers. In 1995, Menatep Bank acquired a controlling packet of shares in VNK, leading to the merger of VNK into YUKOS. LUKoil successfully negotiated the acquisition of Komi-TEK in 1999. Ongoing consolidation has seen the acquisition of several of Sidanko's subsidiaries by rival companies under Russia's complex bankruptcy procedures.[31] TNK took both

31. Of particular note is the experience of BP Amoco, which bought a 10% stake in *Sidanko* from the *Interros* group in 1997 for $571 million. *Sidanko* was sued for bankruptcy in January 1999 by a little-known creditor at the behest of a Russian competitor to Sidanko, and was formally declared bankrupt in May, allowing rival companies to take over several subsidiaries in subsequent bankruptcy auctions and thus stripping Sidanko shareholders of their assets.

Table 4.1 Russia's Major Vertically Integrated Oil Companies in 2000

Company	Oil Production (Mln t)	Gas Production (Bcm)	Oil Reserves (A+B+C1; Mln t)	Gas Reserves (A+B+C1; bcm)	Refined Crude* (Mln t)	Filling Stations
LUKoil	62.18	3.60	3,344	289	23.20	850**
YUKOS	49.55	1.58	2,607	443	23.06	1,278
Surgutneftegaz	40.62	11.14	1,504	489	15.97	~ 470
Rosneft	13.47	5.63	1,573	2,785	7.17	1,087
TNK ***	35.68	2.90	3,707	293	11.58	~ 200
Sibneft	17.20	1.43	753	47	12.56	859
Slavneft	12.16	0.72	286	50	10.83	187
Sidanko***	10.69	1.31	495	78	3.67	~ 40
ONAKO***	7.48	1.53	280	69	4.31	~ 70
Tatneft	24.34	0.75	841	19	5.55	~ 100
Bashneft	11.94	0.39	365	11	19.40	90

Note: All data apply to company operations only in the Russian Federation.
** Crude refined at wholly owned subsidiaries; excludes amount tolled through other plants or facilities.*
*** LUKoil has about 1,020 stations world-wide.*
**** As of 2001, Sidanko and ONAKO are affiliates of TNK.*
Source: Company reports; Ministry of Energy; Infotek, No. 2, 2001.

Chernogorneft and Kondpetroleum from Sidanko, although it subsequently agreed to return Chernogorneft in exchange for a 25% stake in Sidanko.

According to Goskomstat, 132 companies produced oil in Russia in mid-2000. Only 12 of these (11 VICs and *Gazprom*) produce more than 10 Mt each per year (Table 4.2). Although the sector is dominated by the VICs, over 100 small independent crude oil producers accounted for 3% of crude oil production in 2000. The largest among these include BelKamneft (1.6 Mt), Tebukneft (1.0 Mt) and RITEK (0.9 Mt). These independent producers have increased their share of production from just over 2% of total in 1997 to over 3% in 2000. "Foreign" joint ventures accounted for 6% of production in 2000, or 18.9 Mt[32]. The first oil produced by production-sharing (PSA) projects was in 1999, from Sakhalin-2 (owned by Sakhalin Energy Company) and Kharyaga (TotalFina-Elf/Norsk Hydro). Sakhalin-2 produced 143,500 tonnes and Kharyaga 72,300 tonnes in 1999. These figures increased to 1,672,100 tonnes and 515,480 tonnes in 2000.

Nearly all of Russia's 33 oil-producing regions (*oblasts*, republics, *krays*) reported growth in oil output in 1999-2000, including such key producers as Tyumen *Oblast*, where about two-thirds of Russian oil is produced. Gains were also reported in the Komi Republic, Tatarstan and Sakhalin *Oblast*. The few areas reporting declines over the last two years included war-torn Chechnya, Bashkortostan, Kaliningrad *Oblast* and the Udmurt Republic.

32. Many partners described as "foreign" are in fact Russian-owned companies registered in foreign countries to benefit from the special privileges granted to joint ventures with foreign partners. It is estimated that JVs with "genuine" foreign partners produced about nine Mt in 1999, less than half the officially reported total output for all JVs. The real role of Russian companies is likely to grow further, as some of them are buying out their original foreign partners.

Table 4.2 Oil Production by Company in Million Tonnes, 1990 to 1999

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Russia Total	**516**	**462**	**400**	**355**	**318**	**307**	**301**	**306**	**303**	**305**
Rosneft	18.0	16.7	15.2	14.1	12.3	12.7	12.8	13.2	12.4	12.4
of which Purneftegaz	11.8	10.8	9.8	9.4	8.3	8.3	8.5	8.7	8.3	8.2
Lukoil	85.3	80.7	70.8	61.5	56.5	53.4	50.9	53.4	53.8	53.3
of which Kogalymneftegaz	33.2	33.0	29.2	25.5	25.4	24.0	25.0	26.8	26.5	26.7
Langepasneftegaz	29.0	26.1	21.9	17.9	14.8	13.1	12.2	12.6	13.1	6.0
Yukos	73.9	64.5	52.8	44.6	37.3	36.0	35.2	35.4	34.1	34.2
of which Yuganskneftegaz	58.8	50.6	40.7	33.9	28.6	27.1	26.3	26.9	25.7	26.2
Surgutneftegaz	51.1	47.0	42.6	38.1	34.3	33.3	33.3	33.9	35.2	37.6
Sidanko	51.8	42.7	36.8	32.4	25.5	22.8	20.7	20.2	19.9	19.5
of which Udmurtneft	8.3	7.8	7.3	6.8	6.3	6.0	5.8	5.6	5.5	5.4
Slavneft	17.3	16.7	14.6	13.5	13.1	12.8	12.5	12.3	11.8	11.9
Onako	8.5	8.4	7.8	7.2	7.3	7.2	7.6	7.4	7.9	7.4
Sibneft	40.2	35.9	29.9	25.6	22.7	20.4	18.6	18.2	17.3	16.3
Tyumen Oil Co.	61.9	47.4	34.3	28.1	24.7	22.6	21.3	20.9	19.7	20.1
of which Nizhnevartovskneft	59.6	45.2	32.5	26.5	23.2	21.0	19.6	19.3	18.1	18.2
Bashneft NK	27.2	25.0	22.8	20.7	18.0	17.7	16.3	15.4	12.9	12.3
Tatneft NK	34.3	32.5	29.7	25.6	23.6	25.0	24.8	24.5	24.4	24.1
East Siberia Oil & Gas Co.	14.8	13.7	12.2	11.6	11.2	11.1	11.4	11.0	10.8	10.3
RAO "Gazprom"	10.6	11.0	10.4	9.2	7.9	8.7	8.6	9.1	9.5	9.9
Russian independents							0.3	6.6	9.0	8.8
"Foreign" Joint Ventures				8.4	10.7	10.7	15.1	18.0	19.5	18.5

Source: "Fuel & Energy of Russia", A. M. Mastepanov, Ministry of Energy, 2000.

The VICs have now been largely privatised, although Federal government ownership in some of them remains large (Table 4.3). Republic-level administrations also own significant stakes in some VICs.[33] Current plans call for the eventual sale of most of the VIC shares still held by the Federal government. Various politicians have championed the establishment of a state-owned "national" oil company, to ensure oil supplies to the North, to explore or develop resources in difficult or uneconomic regions, to receive licences, which are revoked due to failure to meet license terms and to represent the State interest in PSAs. However, official interest in the idea waned since the election of President Vladimir Putin in March 2000.

►►► ***Remaining Privatisation.*** *The state should continue with its plans to sell off the remaining state holdings in the oil companies in an orderly and transparent fashion. The issue of having a state-owned "national" oil company, given the position of Rosneft as essentially a residual of state oil holdings with little corporate cohesion, needs very careful assessment. While shedding Rosneft's assets, the government could also create a body that would represent its interests in PSAs more efficiently than Rosneft in its current form.*

33. The privatisation process has been criticised by many observers for lack of transparency and for the transfer of assets at very low prices to industry insiders. In the highly controversial "loans for shares" programme of 1995, a number of financial institutions received shares as collateral for loans to the government that were subsequently not repaid.

Table 4.3 State Shareholding of Russia's Major Vertically Integrated Oil Companies (%)

	1993	1994	1995	1996	1997	1998	1999	2000
LUKoil	90.8	80.0	54.9	33.1	26.6	26.6	16.9	14.1
YUKOS	100.0	100.0	48.0	0.1	0.1	0.1	0.1	0
Sidanko	n.a.	100.0	85.0	51.0	0	0	0	0
Surgutneftegaz	100.0	40.1	40.1	40.1	0.81	0.81	0.8	0.8
Tyumen Oil Co.	n.a.	n.a.	100.0	100.0	51.0	49.8	49.8	0
Eastern Oil Co.	n.a.	100.0	85.0	85.0	36.8	36.80	36.8	36.8
East Siberian Oil & Gas Co.	n.a.	100.0	85.0	38.0	1.0	0.95	1.0	1.0
Orenburg Oil Co.	n.a.	100.0	85.0	85.0	85.0	85.0	85.0	0
Rosneft	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Slavneft	n.a.	83.0	83.0	79.0	75.0	75.0	75.0	75.0
Norsi-Oil	n.a.	n.a.	85.5	85.4	85.36	85.4	85.4	85.4
Sibur	n.a.	n.a.	85.0	85.0	85.00	14.8	14.8	0
Sibneft	n.a.	n.a.	100.0	51.0	0	0	0	0
Komi-TEK	n.a.	100.0	100.0	91-95	1.1	1.1	1.1	1.1

n.a. means company not in existence.
Source: Infotek, No. 11, 2000.

Several oil companies have been criticised for lack of attention to good corporate practice, shareholder rights and transparency. This is true in part because the underlying legal and regulatory frameworks for private property, stock and bond operations, bankruptcy and corporate activities are still being established. Much of the problem arises from a lack of implementation of statutes that *do* exist.

►►► ***Corporate Transparency****. The government should continue to develop an underlying legal and regulatory framework covering corporate practices and shareholder issues (the Civil Code, the Law on Banking, and the Law on Bankruptcy). The government should also pursue the application of its laws in practice. This could include a requirement for the oil companies to practice regular financial reporting according to international auditing and accounting standards and to undergo international reserve audits.*

Key governmental bodies relevant to the oil sector include the following:

- the Ministry of Energy;
- the Ministry of Natural Resources manages and protects Russia's natural-resource base and plays a major role in licensing fields;
- the Ministry of Economic Development and Trade is responsible for Production Sharing Agreements;
- the Anti-Monopoly Ministry conducts general anti-trust policy and regulation of certain monopolies, including the railroads, which are much used for the transport of oil products;

- the Federal Energy Commission (FEC) regulates prices and tariffs of the so-called "natural monopolies" in the energy sector, including the pipeline systems of Transneft and Gazprom;
- the Commission on Oil and Gas Pipeline Use regulates access to trunk oil and gas pipeline systems, particularly those for export.

►►► ***Strengthening Regulatory Bodies.*** *The government should strengthen the role of the regulatory bodies, notably the Federal Energy Commission and the Anti-Monopoly Ministry, to ensure a competitive "level playing field" for all companies.*

CRUDE OIL RESERVES AND PRODUCTION

Crude Oil Reserves

The government does not publish data on the size and location of the country's oil reserves, although a number of figures have been informally disseminated. Analytical documents by the Ministry of Energy state that close to half of Russia's oil reserves have already been extracted. Production through 1999 was about 19.5 billion tonnes, and this analysis implies that a similar amount remains to be extracted. Moreover, since existing law states that only 30% of so-called "explored reserves" are eligible for development on production-sharing terms and fields with some six billion tonnes have been nominated, total "explored reserves" again work out to approximately 20 billion tonnes. (see Map 1).

Russian methodology for defining reserves differs from that used by the international oil industry (Table 4.4). Reflecting its Soviet origins, the system pays less attention to profitability than to technical feasibility. Russian nomenclature designates different reserve categories in descending order of geological certainty, reflecting the degree of exploration that has occurred. "Explored reserves" are the sum of Russian categories A, B, and C, while "proven reserves" are the sum of categories A, B and a subset of C referred to as C_1 ($A+B+C_1$). Well-test or log data are required for reserves certified as C_1 or higher. C_2 reserves are typically extensions of proven fields. C_3/D_0 "reserves" are based only on seismic data, while D_1 and D_2 are speculative estimates of unsurveyed prospects in proven or unproven petroleum provinces.

To increase their attractiveness to outside investors, Russian oil companies now release figures on their $A+B+C_1$ reserves as well as reserve audits performed by Western petroleum engineering firms. The $A+B+C_1$ figures probably substantially overstate the relative reserve position of Russian producers.[34] Most independent Western estimates put proven Russian oil reserves at about half of the $A+B+C_1$ figure. A typical estimate is the 6.7 billion tonnes cited in the *BP Statistical Review of World Energy* (June 2000). The BP figure is about 4.7% of the world total. This would rank Russia well behind the big Middle Eastern producers, somewhere between Venezuela (10.5 billion tonnes) and Mexico (4.1 billion tonnes).

34. Western reserve estimation procedures, however, have an inherent tendency to *understate* recoverable reserves. This results in the common phenomenon of upward revisions in reserves during the life of the field with improved knowledge and new technology.

Table 4.4 Difference in Reserve Classification

Soviet Reserve Classification		Western Reserve Classification
Explored/Commercial reserves A + B + 30% of C_1		Proved: Reserves which geological and engineering or drilling data demonstrate to be recoverable under existing economic and operating conditions.
A	• Geologically & geophysically examined • Delineated by exploration & production • Engineering data show recoverability • Represent reserves in current production	
B	• Geologically & geophysically examined • Evaluated by adequate drilling • Engineering data show recoverability • Represent unused producing capacity	
C_1 30%	• Reserves adjacent to A and B categories • Geologically & geophysically evaluated • Verified by minimal drilling • Engineering data show partial recoverability (30% will shift to B and then A categories)	Probable: Incompletely defined reserves estimated to occur: • In known producing areas / extensions of endowed areas • In undiscovered areas within known resource-bearing geologic trends • Recoverable under existing economic and operating conditions
Prospective Reserves Remaining 70% of C_1 + C_2 + D_1 + D_2		
C_1 70%	• As above	Possible: Inferred reserves estimated to occur: • In undiscovered areas analogous to other known resource-bearing geologic trends • Recoverable under existing economic and operating conditions
C_2	• Presumed to exist, based on favourable geologic and geophysical data analogous to that of verified reserves	
D_1	• Speculative reserves presumed to exist, based on geologic analogy to reference areas • Some will shift to "C_2" category	
D_2	• Speculative reserves presumed to exist, based on geologic analogy to reference areas • Less evaluated than "D_1" • Some will shift to "D_1" category	

Several Russian oil companies have hired Western petroleum engineers to re-evaluate their reserves according to Western practices. The results of these evaluations have varied substantially from company to company. In general, however, the Western audits report much smaller figures for "proven reserves" than the A+B+C_1 measure. The US engineering company Miller & Lents estimated LUKoil's nation-wide proven oil reserves in 1998 at approximately 1.46 billion tonnes (10.7 billion barrels), just over half of LUKoil's reported A+B+C_1 total of 2.8 billion tonnes.

Most of Russia's remaining oil resources lie in West Siberia, which currently accounts for just over two-thirds of national production. Various published sources indicate that West Siberia contains about 72% of Russia's remaining $A+B+C_1$ reserves, although most of it is in small, deep fields with low permeability and complex subtle traps. About three-quarters is in fields currently under development. The rest of the country's $A+B+C_1$ reserves are scattered in the mature Volga-Urals region (14%), the relatively underdeveloped Timan-Pechora Basin in north of European Russia (7%) and East Siberia (4%). The remaining 3% are offshore, in the Pechora Sea and the Sakhalin shelf, and in marginal old producing regions such as the North Caucasus and Kaliningrad.

Among the more promising areas for future oil development is the Timan-Pechora Basin, which straddles the Komi Republic and the Nenets Autonomous *Okrug* (Arkhangelsk *Oblast*) in northern European Russia. According to a LUKoil assessment, this region contains an estimated 1.35 billion tonnes of $A+B+C_1$ reserves, with a yet-undiscovered potential of 3 billion tonnes. Although production has been going on there for several decades, the Timan-Pechora fields were thought to be much smaller than those in West Siberia and so did not witness the same intensive push for development during the Soviet period. Other promising areas include East Siberia and the Far East, estimated by Russian sources to contain as much as 14 billion tonnes. The $A+B+C_1$ portion of these reserves, approximately 1.1 billion tonnes, is more modest because of limited exploration activity. Most East Siberian oil fields are not yet in production. This vast area yielded less than 1% of Russian oil output in 1999.

►►► ***Official data on russian reserves should be made public.*** *Given the widespread dissemination of unofficial figures on oil reserves and the reserve limitations set for PSAs, it would be helpful to have official data on Russia's reserve base on a regular basis. More transparent and reliable data would increase investors' confidence.*

The structure of the Russian reserve base has been deteriorating over the past two decades. An increasing portion of remaining reserves falls into the "difficult-to-recover" category (55-60% currently). Over 70% of reserves now being operated yield such low flow rates that their development is only marginally commercial. Approximately 55% of total oil reserves now in development yield flow rates of 10 tonnes per well per day or less. The average daily flow per well dropped from 27.6 tonnes in 1980 to 11.6 tonnes in 1990 and to only 7.1 tonnes in 1999. The 1990s saw a considerable depletion of reserves due to a sharp decline in exploration activity and expenditures.

The study, *Basic Concepts for Russia's Petroleum Industry Development*,[35] lists several measures to reverse the deterioration in the upstream oil sector, including measures to improve the investment climate. It calls for amendments to the existing legislative and regulatory base, which the report considers "completely inadequate". It advocates drafting a comprehensive package of consistent laws and regulations to establish a flexible tax system capable of encouraging the development of largely depleted reserves, the use of new technologies to develop reserves, the revitalisation of idle or shut-in wells and the use of enhanced recovery methods.

35. This document was prepared by the Ministry of Energy and energy experts and submitted to the Government Hearing on 15 October 1999. (See www.mte.gov.ru or www.enippf.ru.)

Crude-Oil Production

The rapid growth in Soviet oil production after World War II resulted largely from the discovery and exploitation of a series of extremely large fields. As recently as 1986, 70% of Soviet oil production came from 20 large fields that accounted for 60% of reserves. Currently, 82 fields (19 so-called "giants" and 63 "large" fields) account for over 70% of production and over 60% of remaining reserves (defined by Russian standards) (Table 4.5). To offset the declines at the large older fields, production has shifted progressively to widely scattered smaller fields. This shift has led to problems in providing needed infrastructure and access as well as to lower rates of flow. Average daily production per well has fallen to about a quarter of that in the mid-1970s. The increased drilling and infrastructure required for smaller and smaller incremental flows of oil have raised oil production costs significantly since the 1970s.

Table 4.5 Geographical Distribution of Oil Production in the Russian Federation (in Million Tonnes)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Russian Federation	**516**	**461**	**396**	**344**	**316**	**307**	**301**	**306**	**303**	**305**	**323**
European Russia	**25**	**23**	**20**	**17**	**15**	**13**	**14**	**15**	**16**	**15**	**16**
Volga	**54**	**51**	**46**	**41**	**37**	**40**	**40**	**40**	**42**	**42**	**46**
of which Tatarstan	34	32	30	26	24	26	26	26	26	26	27
Urals	**59**	**58**	**52**	**47**	**42**	**42**	**41**	**40**	**39**	**38**	**38**
of which Bashkortostan	27	26	24	22	19	18	14	13	13	12	12
Orenburg Oblast	12	12	10	8	8	9	9	9	9	9	9
Perm Oblast	12	11	11	10	9	9	9	10	9	9	9
Siberia	**378**	**332**	**278**	**240**	**222**	**212**	**206**	**210**	**207**	**210**	**223**
of which Tyumen Oblast	365	320	267	231	214	202	197	200	198	200	213
Tomsk Oblast	10	10	9	7	7	7	7	7	6	6	7
Sakhalin Oblast	2	2	2	2	2	2	2	2	2	2	3

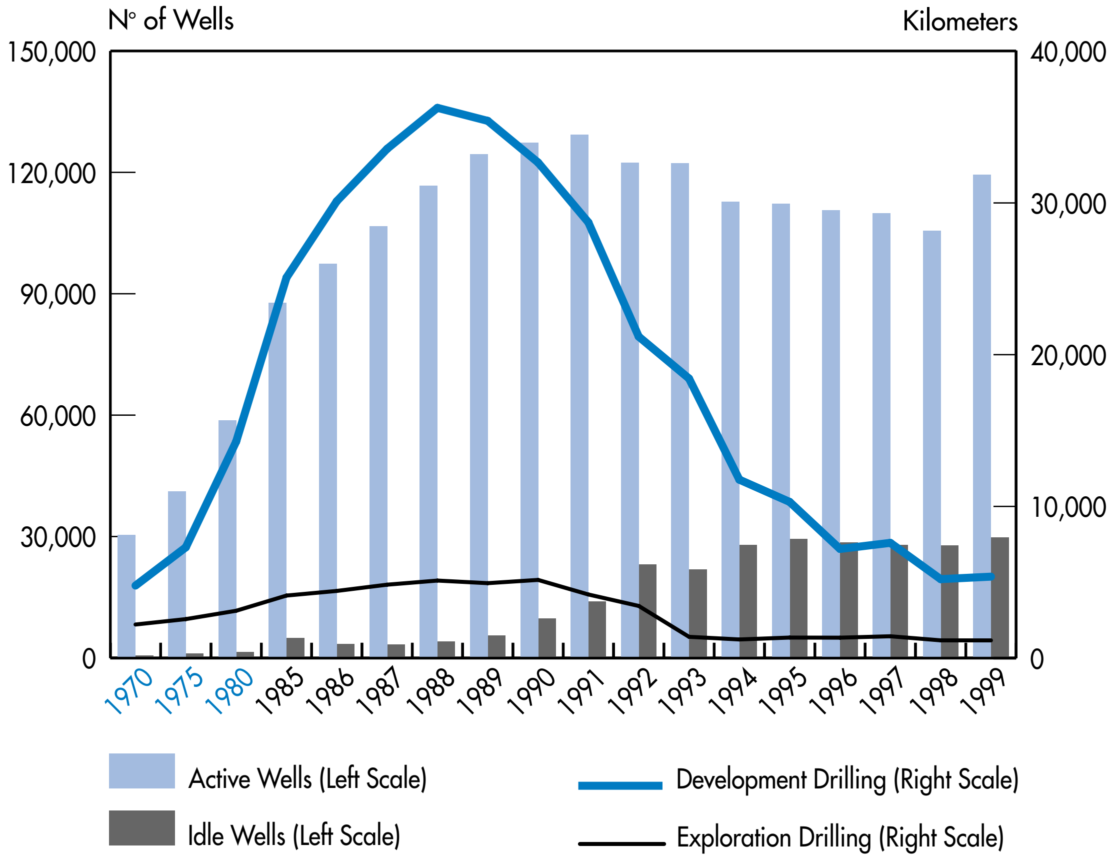
Russia ranks third behind Saudi Arabia and the United States among world oil producers, although its output has declined significantly from the 1987 peak of 569.5 Mt. Production bottomed out in 1996 at about 47% of the peak level and rose slightly in 1997. Although the improving trend reversed in 1998, due in part to the Russian financial crisis, production recovered again in 1999 and 2000 (Table 4.5). Output in 2000 was 323.2 Mt, up 6.0% from the previous year. The major force behind the upturn in 1999-2000 was the rebound in international oil prices that occurred after March 1999, when OPEC, in collaboration with some major non-OPEC producers, reduced oil output and exports to international markets. The resulting sharp rebound in world prices led to a substantial increase in revenues for Russian producers and allowed them to increase capital spending on drilling and repairs. A total of 36 new fields produced their first oil in 1999, the largest number of fields commissioned in a single year in over a decade. In 2000, 43 new fields came on stream. (In 1998, only 20 new small fields were brought on stream.)

A substantial increase in investment by Russian oil companies bolstered the turnaround in oil output. Capital investment in extraction increased by 25% in real terms in 1999.

In 2000 it doubled that of 1999, rising by 102.4% to 110.6 billion roubles, approximately $4 billion[36]. Of this, 31.2% was spent on drilling. For the first year since the early 1990s, 1999 saw an increase in the number of active oil wells, almost 14,000 wells or 13% (Figure 2). Preliminary data for 2000 show an increase of over 65% in development drilling. Nearly a hundred new fields came on stream from 1998 to 2000. There was an even larger run up in well work-overs and in idle wells put back on line. The share of idle wells dropped from its peak of 21% in 1995 to 18% in 2000.

A new oil basin with reserves similar in size to those of West Siberia does not seem to be on the horizon. In the short term, therefore, Russian oil output hinges essentially on how long West Siberia's current plateau of 200-220 Mt can be maintained. Better reservoir management and development of small and difficult fields could attenuate its depletion. Production costs and international oil prices will be crucial in this regard. The medium-term outlook will depend on how fast new reserves can be put into production in less mature provinces, such as Timan-Pechora and Sakhalin. In the long term, new provinces such as East Siberia, the Pechora Sea, or the Russian sector of the Caspian could make sizeable contributions to the overall production profile.

Figure 2 Upstream Oil Activity in Russia, 1970 to 1999



Source: 1970-1989: IEA 1995 "Energy Policies of the Russian Federation".
1990-1999, "Fuel & Energy of Russia", A. M. Mastepanov, Ministry of Energy, 2000.

36. Real investment activity is much higher than is indicated by the conversion of rouble outlays into dollars at the average exchange rate.

Many producing fields require modern reservoir management to remedy some of the damage caused by over-production, which in many cases involved quasi-systematic water injection. Employed in West Siberia since the beginning to boost output to maximum levels quickly, this has resulted in an increasingly large water cut[37]. By 1990, the water cut was 76% for Russia as a whole, up from about 50% as recently as 1976. Injection of associated gas accounted for only 1.9% of Russian oil production in 1999. The share of oil produced from free-flowing wells dropped from 51.8% in 1970 to only 12.0% by 1990 and 8.4% by 1999. Modern tertiary recovery techniques will be required to maximise reservoir drainage as well as oil reservoir formation and well treatment in less permeable reservoirs.

Because of these underlying factors, Russian oil production levels could have been sustained into the 1990s only through massive new drilling and new-field development. The abrupt shift in the way capital investment are funded which came with the transition complicated the development of new fields required to replace the ageing giants or to boost drilling rates sufficiently to offset declines in older fields. By 1998, investment in real terms was a mere 24% of what it was in 1990. Annual development drilling had dropped to 4.3 million metres from 31.6 million metres in 1990. Additional capital needs for well work-overs and preventive maintenance often went unfunded.

The enormous potential of modern reservoir management and other upstream services, to expand production and improve productivity is amply illustrated in the results achieved by some Russian companies over the last two years. According to YUKOS, its partnership with the Franco-American Schlumberger was instrumental in improving efficiency and effectiveness in much of its upstream operations in 2000, adding an additional million tonnes of output just from yield – enhancement measures. TNK is now engaged in a similar relationship with the US service company, Halliburton. Russian oil companies choosing foreign service companies to enhance oil production would seem to reflect the weakness of Russian service companies in terms of quality of materials, tools and equipment which often fails to meet modern requirements and standards. However, Russian regional service companies created from former geological and geophysical units, received a tremendous boost over the 1999-2000 period by the combination of the rouble devaluation and higher oil company investments due to higher international oil prices. Modern technologies, equipment and specialised services will be essential for them to gain and maintain a competitive edge.

Outlook for Oil Production

The *Main Provisions of the Russian Energy Strategy to 2020* project oil output to reach 335 Mt in 2010 and 360 Mt in 2020. The main oil-producing area is still expected to be West Siberia, although its share is projected to fall to 55%-58% of the national total by 2020, from 68% currently. Production in newly-emerging areas such as Sakhalin, Timan-Pechora, and East Siberia will rise. The Russian Energy Strategy to 2020 estimates that investments of approximately \$40 to \$50 billion will be needed to 2010 to reach the production targets of 335 Mt in 2010. By 2020, a further \$70 to \$90 billion will be needed to reach production targets of 360 Mt. This works out to an average of \$8 to \$10 billion per year over the 20-year period; 1999 upstream investment was less than \$2 billion, while 2000 saw less than \$5 billion.

37. Water cut is the percentage of water in total recovered liquids. Certain old Russian wells produce 90% water.

These estimates are reasonable for the production targets envisioned. The rate of decline for "flowing oil" (production from currently producing fields) is expected to slow as more regular maintenance is done. A key question, however, is how such increased investment can be financed. Because of the lack of adequate incentives for large-scale foreign investment, the main source may have to be Russian companies' own funds. Additional planned sources of finance are foreign direct investment, mainly through PSAs, and bank loans.

The Energy Strategy envisions 0.5% average annual growth in oil production over the period. But future implementation of the Tax Code and the PSA regime and the liberalisation of exports, could lead to much higher output. In WEO 2000, the IEA projects oil production at 370 Mt by 2010 and 400 Mt by 2020, for an average annual production increase of about 1%.

OIL SECTOR REFORM AND THE LEGISLATIVE FRAMEWORK

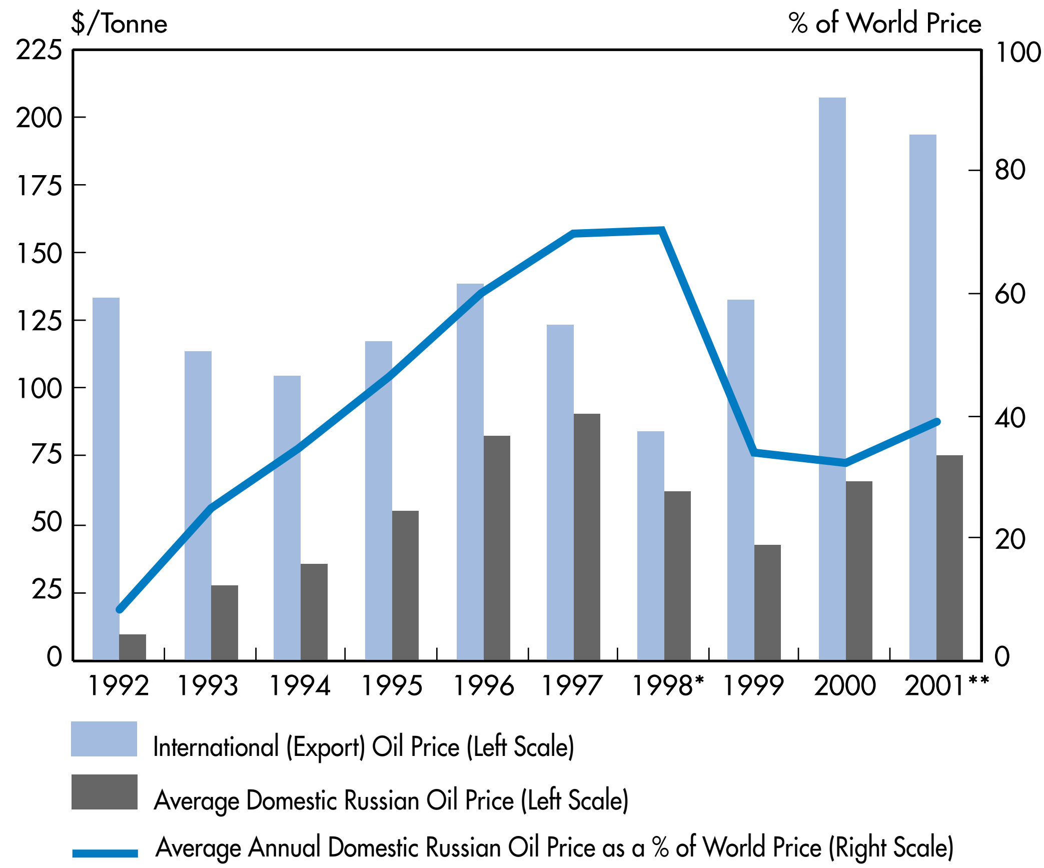
Oil Pricing Policy

Oil pricing became largely determined by market forces after September 1992, when partial oil price liberalisation was introduced. Crude oil was completely liberalised on 1 January 1995, and the liberalisation of oil-product prices came later the same year. Most domestic sales of oil and refined products are now negotiated between buyers and sellers. Since 1998, however, in an effort to exert greater influence and control over the domestic oil market, the government has reintroduced domestic delivery requirements for crude oil and for some refined products.

Oil prices generally increased through 1998, moving closer to parity with international prices (Figure 3). The average domestic price for crude oil advanced from *less than 1%* of world levels in December 1991 to close the gap with international prices in the first quarter of 1998, aided somewhat by a sharp decline in international prices in that year. With the rapid run-up in international prices that began in the second quarter of 1999, Russian domestic price weakened relative to international markets. In the third quarter, it amounted to only 28% of the international price. The average domestic price finally began to gain ground in the fourth quarter of 1999 and into the first quarter of 2000, when it reached 30% of the international price and 42% by the second quarter of 2001. Many factors have restrained domestic price adjustments, including the re-imposition of administrative limits on exports of both crude and refined products. These limits are aimed deliberately at keeping the domestic market oversupplied and relatively slack.

Government purchases for state exports were a major factor holding down the domestic price of crude. They were finally being eliminated in July 1997. They accounted for a large share of exports and they maintained the role of the state as the largest single

Figure 3 Average Annual Russian Crude Oil Price as a Percentage of "World" Price



** After the August 1998 rouble devaluation, 3Q-4Q 1998 domestic oil prices dropped below $40/tonne from a high of $93/tonne in 1Q1998 (at which time it was at 98% of international (export) oil prices).*
*** Half year.*

purchaser of crude oil. The state exports programme resumed in late 1998 under the Primakov government.

One factor currently distorting the domestic crude market and keeping domestic prices down is the widespread use of "transfer pricing" within the VICs. The device is used largely to minimise taxes, as much upstream taxation is based on gross revenues. Also, a high percentage of crude deliveries occur outside the VICs through accounting practices which further reduce the amount of crude sold domestically in a truly commercial way. According to Russian experts' estimates, only about eight Mt of crude are sold domestically on commercial terms, less than 3% of the total amount produced.[38] To combat this trend and to increase tax collection, a new mineral production tax will be introduced in January 2002. It will be charged at a set rate per ton, eliminating two taxes based on gross revenues. The new will be indexed to international oil prices.

►►► ***Creation of an Oil Exchange to Establish Benchmark Prices.*** *To alleviate distortions in the domestic crude-oil market, an oil exchange could be established to provide benchmark prices to guide market participants.*

38. *Krasnoye Znamya*, Tomsk, 25 May 2000.

Another key element of oil-pricing policy is the export tax, which serves essentially as a wedge between domestic and international prices. After abolition of the export tax in July 1996, the Primakov government re-introduced it in January 1999, to capture some of the gains made by exporters in the wake of the rouble devaluation. Because it varies with the market price, it was actually suspended in the first quarter of 1999 because of low international prices. It came into effect again following the rise in international oil prices in March 1999. The export tax was 2.5 euros per tonne in April 1999 and increased progressively with the price of oil to 42 euros in December 2000. The government subsequently announced a cut to 22 euros, which took effect on 17 March 2001, but then raised the tax back to 30.5 euros per ton on July 1, 2001 in line with the changes in export oil prices.[39]

►►► ***Trade Liberalisation.*** *It is important for the Government to examine the remaining obstacles to trade liberalisation and international crude-oil price parity. Obstacles include domestic delivery requirements, the programme of exports for state needs, export taxes, refined-product export limits and the hard-currency components of oil transport tariffs. These measures, which protect domestic consumers, destabilise export earnings and discourage investment (see Annex A).*

Legislative Framework

Over the past decade, a number of important laws relating to the hydrocarbon sector were passed, and several important pieces of legislation are pending. The key oil-related legislative acts include:

- the Law on Underground Mineral Resources;
- the (draft) Oil and Gas Law;
- the Law on the Continental Shelf;
- the Law on Production Sharing;
- the Law on Natural Monopolies; and
- the (draft) Law on Trunk Pipelines.

The *Law on Underground Mineral Resources*, also known as the Subsurface Resources Law, was passed by the *Duma* in 1992. It set a legal framework for all mining operations, including petroleum production. It established the state as the exclusive owner of all mineral resources, but allowed private and state-owned entities to lease exploration and production rights via licenses. The Law required that licenses be issued only through public competitive tenders. Subsequently, in July 1992, regulations were issued on the procedures for licensing to exploit mineral resources. A State Committee for Geology and the Use of Underground Resources (now the Ministry of Natural Resources) was established as the Federal body responsible for issuing licenses. “Joint licensing” is, however still the rule. Known as “dva klucha”, this requires approval by both Federal and regional authorities. Licensing and tendering have since become the major tools used by regional administrations to regulate the development of hydrocarbons on their territories.

39. The Duma wants to set oil export taxes through legislation rather than administratively, as now. In July 2001, the Duma passed on first reading a draft law on export taxes. The bill sets a maximum rate for oil export taxes based on world market prices that varies from zero up to 53.65 euros per ton. The draft law fixes product export taxes at a proportion of the prevailing crude export tax. The law establishing export taxes in legislation was to go into force on 10 September 2001, but as of publication of this Survey the latest adjustment in the export tax (23 September 2001 to 23.4 ecu/t) was again made by the government commission.

The draft *Oil and Gas Law* was designed to complement the 1992 Law on Underground Resources by establishing new licensing and operating rules for the oil and gas industry. The *Duma* passed it in July 1995, but it failed to receive endorsement by the Federation Council and the President. The impetus behind it gradually waned, and the focus shifted to production-sharing legislation and improvements to the existing Law on Underground Mineral Resources.

The *Law on the Continental Shelf* was passed by the *Duma* in October 1995 and signed into law by President Boris Yeltsin. It gave the Federal authorities exclusive rights to permit and regulate exploration and development of the shelf by either foreign or Russian investors after tenders and auctions. It defined Russia's jurisdiction over the shelf as applying to the exploration and production of mineral resources, the construction of facilities for drilling and the laying of cables and pipelines.

The *Law on Natural Monopolies* went into effect in August 1995 and covers many activities in the Russian energy sector. It identified "natural monopolies", such as the oil pipeline operator, *Transneft*, and the oil product operator, *Transnefteprodukt*, whose activities fell under its purview. It established several state monitoring and regulatory bodies, including the Anti-Monopoly Ministry and the Federal Energy Commission. A series of subsequent resolutions spelled out the organisation, operations and powers of these bodies.

The draft *Law on Trunk Pipelines*, has been under consideration in the *Duma* for some time. Its passage was one of several measures agreed to by the government to secure release of the third tranche of a $1.2 billion loan from the World Bank in May 1999. The bank required non-discriminatory access and tariffs as well as restrictions on vertical integration across oil extraction, transportation, refining and distribution. Still not approved, the bill would ensure that independent producers have guaranteed access to all pipeline systems, even those belonging to non-monopolist providers. The draft also requires state ownership of a blocking stake in any pipeline transportation system on Russian territory. It ensures the indivisibility of existing pipeline transportation systems, effectively prohibiting the break-up of the existing pipeline monopolies.

►►► ***The Trunk Pipeline Law should provide for privately financed, owned and managed pipelines.*** *It is important to get this law right. Otherwise it could frustrate the development of private pipelines and even retard investment in the upstream oil industry, especially in newer regions where new pipelines will be needed, such as East Siberia and Timan-Pechora.*

Tax Policy

The number of taxes and payments collected for Federal, regional, and local budgets now numbers nearly 100 in some regions. The system is prone to frequent changes, which can make it very difficult to carry out a business plan. It is based excessively on revenue and volume rather than profit.

The Russian tax structure showed its shortcomings in 1998 when international oil prices fell to record low levels, putting Russian producers in a severe squeeze as revenues dropped. In aggregate, the oil-extraction industry ran at a loss during the 1990s, due largely to heavy taxation. Even in the few periods when the industry did not post aggregate losses, the tax take was quite high and operating margins were low. Taxes paid on the average producer through much of the 1990s amounted to over 100% of the operating margin. Thus the tax system can render uneconomic virtually any type of project requiring large capital investment. The normal corporate profits tax, reduced from 35% to 30% on 1 March 1999, is to be reduced still further to 24% as of 1 January 2002 with the elimination of all exemptions and concessions. Although a positive step in terms of simplifying the tax system, past reductions in the corporate profit tax rate have scarcely applied to the oil sector, since the burden of revenue-based taxes often left producers with no taxable income. The industry found it extremely difficult to self-finance its investment needs. Even in June 2000, with world prices at near-record levels, the government take had fallen only to 90% of revenues for domestic sales and 56% for export sales.

Table 4.6 Calculation of Crude Oil Prices, Taxes and Costs, $/Tonne

	June 1998		**June 1999**		**June 2000**		**June 2001**	
	Domestic	**Exports**	**Domestic**	**Exports**	**Domestic**	**Exports**	**Domestic**	**Exports**
Refinery input price/export price	75.2	91.9	25.7	112.0	60.0	199.0	80.0	191.4
Transport to refinery/export point	6.1	17.1	3.3	11.0	2.9	10.2	1.9	17.7
Export tax	–	–	–	4.9	–	19.7	–	17.1
Domestic wholesale price/ net export price (to non-FSU)	69.1	74.9	22.4	96.1	57.1	169.2	78.1	156.7
VAT (21.5%)	14.8	–	4.0	–	12.3	–	16.8	–
Excise tax	9.0	9.0	2.3	2.3	1.9	1.9	1.9	1.9
Suppliers price	47.8	65.8	16.2	93.8	42.9	167.2	59.4	154.8
Government funds and charges	11.2	14.1	3.5	16.3	8.0	28.5	10.7	26.4
Royalty (10%)	4.8	6.6	1.6	9.4	4.3	16.7	5.9	15.5
Geology fee (8%)	3.8	5.3	1.3	7.5	3.4	13.4	4.8	12.4
Geology fee (recovery 4%)	1.9	2.6	0.6	3.8	1.7	6.7	2.4	6.2
Road users tax (4%)	1.2	1.6	0.4	2.3	1.1	4.2	1.5	3.9
Other taxes *	3.3	3.3	0.8	0.8	0.9	0.9	0.9	0.9
Production costs **	39.6	39.6	11.5	11.5	8.5	8.5	16.5	16.5
Gross profit for oil producer	– 2.9	12.1	1.2	66.0	26.4	130.2	32.2	111.9
Corporate profits tax***	– 1.0	4.2	0.3	19.8	7.9	39.1	9.7	33.6
Profit after tax	– 1.9	7.9	0.8	46.2	18.5	91.1	22.6	78.3
Government take (% of gross revenues)	**45.3**	**29.8**	**39.2**	**38.7**	**50.2**	**44.8**	**48.7**	**41.2**
Government take (% of net revenues)	**412.8**	**104.4**	**216.3**	**52.6**	**87.6**	**56.2**	**90.9**	**57.1**

** Other non-revenue taxes, including property tax and social taxes not included in operating costs.*
*** Including depreciation.*
**** 35% through February 28, 1999; 30% thereafter.*

Besides VAT and profits tax, which apply to all sectors of the economy, a number of special taxes apply to crude-oil production. The most important has traditionally been the excise tax, the proceeds of which go to the Federal budget. Established in August 1992, it was initially set at 18% of product sold, but it was later modified to reflect production costs. To simplify its administration, the excise tax was changed in April 1994 from a percentage *ad valorem* to a rouble tax per tonne, while maintaining its variable character. Initially the tax was indexed to the rouble-dollar exchange rate, but the indexation was removed in 1997. The value of the tax plunged in real terms with the devaluation of the rouble in 1998. In 2000, the variable character of the excise tax was eliminated altogether in favour of a flat tax of 55 roubles per tonne for all producers. The new Tax Code was supposed to eliminate the excise tax on crude-oil production altogether, but in the event it was retained, and raised to 73.9 roubles per ton ($2.60), effective 1 October 2001.[40]

Royalty payments for subsoil use were introduced in mid-1992. The royalty rate varies between 6% and 16% of the value of product sold, and is determined by negotiation, or through bidding in the case of new fields. The average is about 8%. Forty percent of the proceeds of the royalties go to the Federal budget, Regional and local budgets each receive 30%. The royalty will be eliminated with the introduction of the mineral production tax, effective 1 January 2002.

A geology fee known as the Mineral Replacement Tax (MRT) covered the exploration activities contracted for by the Ministry of Natural Resources, although a portion is returned to the oil companies for certain types of exploration activity. The rate ranged from zero in the older oil-producing areas to 10% for areas where state geological exploration is heavier. This special levy has long been contentious. It has failed to stimulate geological exploration or add to actual reserves. The geology fund was eliminated in 2000 and the fee itself will also be eliminated with the introduction of the new mineral production tax.

The Federal, regional and local governments have introduced a series of special-purpose levies that all companies must pay, including those in the oil sector: road-use tax, property tax and land-use tax. Some are accounted for in production cost (*sebestoimost*), while most are paid out of profit.

The government's plans to reform and simplify the tax structure through a new Tax Code have been held up since 1995. Part One of the new Tax Code, which establishes general rules governing tax payments and penalties and which regulates relationships between taxpayers and tax agencies, went into effect on 1 January 1999. Remaining sections of Part Two (including natural resource taxation) were recently passed by the Duma and Federation Council, to go into effect 1 January 2002. Although the new Tax Code was intended to shift the focus of oil taxation from volume to profits, a new mineral-production tax was introduced, which is volume-based. Originally, the new Tax Code was to include only three taxes on oil.

Goal of Tax Reform	**Effective January 2002**
A relatively low royalty	New Mineral Production Tax replaces royalty, MRT and excise tax
A profit tax applicable to all corporations	Profit tax reduced to 24%
An excess-profit tax to capture resource rents and specifically tied to project rates of return.[41]	Still in the drafting phase

40. It is unclear whether the new mineral production tax introduced in chapter 26 of Part II of the Tax Code, effective 1 January 2002 will replace the excise tax as well as the royalty and geology fee. Confusion exists due to the seeming contradiction in chapter 22, which increases the rate of the excise tax.
41. The 1998 draft law introducing this tax (*Tax Law on Incremental Revenue*) allows oil producers to decide whether the tax is levied on fields as a whole, on each licensed block individually or on a group of licensed blocks, based on the ratio of revenues to accrued costs (the "R" factor). The tax base is defined as the value of hydrocarbons produced, sold or turned over for processing, reduced by deductible costs. Tax rates would be set annually for each licensed block or group of blocks depending on the R-factor for

The goal of the reform was to create a self-regulating tax system under which the state does not require more money from oil companies than what they are capable of paying. Ideally, it would have matched the underlying geological condition of the country and the economics of individual projects. Another part of the planned tax reform is the implementation of a special tax regime for marginal wells, defined as those yielding five tonnes or less per day. The goal is to lower taxes on so-called "low-flow wells" to the point where they become profitable to exploit. A draft law to this effect is still before the Duma. It could potentially affect as much as 30%-40% of current Russian production. (Such a special regime would probably not be needed if the excess-profit tax were properly calibrated to capture resource rents.)

Instead of the oil-tax concepts previously espoused in the Tax Code, the Duma passed a law introducing a new tax on the production of mineral resources, which was subsequently approved by the upper house, the Federal Council. This new "unified" mineral tax, introduced as an amendment to chapter 26 of Part 2 of the new Tax Code, eliminates the existing mineral replacement tax (geology fee) and royalty on crude oil production. Elimination of the excise tax is unclear due to contradictions raised in chapter 22. The new oil production tax, which is slated to become effective in January 2002, has a base rate fixed at 340 rubles ($12) per ton for the period to 2004, although this amount is indexed to international oil prices.[42] Aggravated by the oil companies' widespread use of transfer pricing and other manipulations that reduce revenue-based taxes considerably, the Duma opted for tax with a fixed rate per ton. The new tax demonstrates a major breakdown in the consensus that had been established in Russia about the defects of the current system and the need to create a self-regulating tax mechanism based mostly on profits. Russian industry support for profit-based tax reform is largely dependent on the state of international oil prices. Momentum behind reform builds when prices are lower and wanes when prices are higher.

Frequent tax changes are inherent in regimes based on gross revenues, because governments must make periodic adjustments to benefit from changes in prices or costs. Profit-based systems are more self-adjusting and give investors a better basis for assessing fiscal impacts over the lives of their projects. Profit-based systems do not impose heavy tax burdens in the early years of production. Figure 4 compares impacts on rates of return and tax revenues over the life of the same oil project under the Canadian tax system, representative of profit-sensitive tax regimes, and the Russian system, which is essentially based on gross revenues or production volumes. The new mineral production tax, effective January 2002, maintains the up-front nature of Russian government take, depicted in Figure 4. Taxation that aims to maximise short-term government revenue may jeopardise the long-term economic goals of attracting investments, providing employment and income, and widening the tax base. Finding

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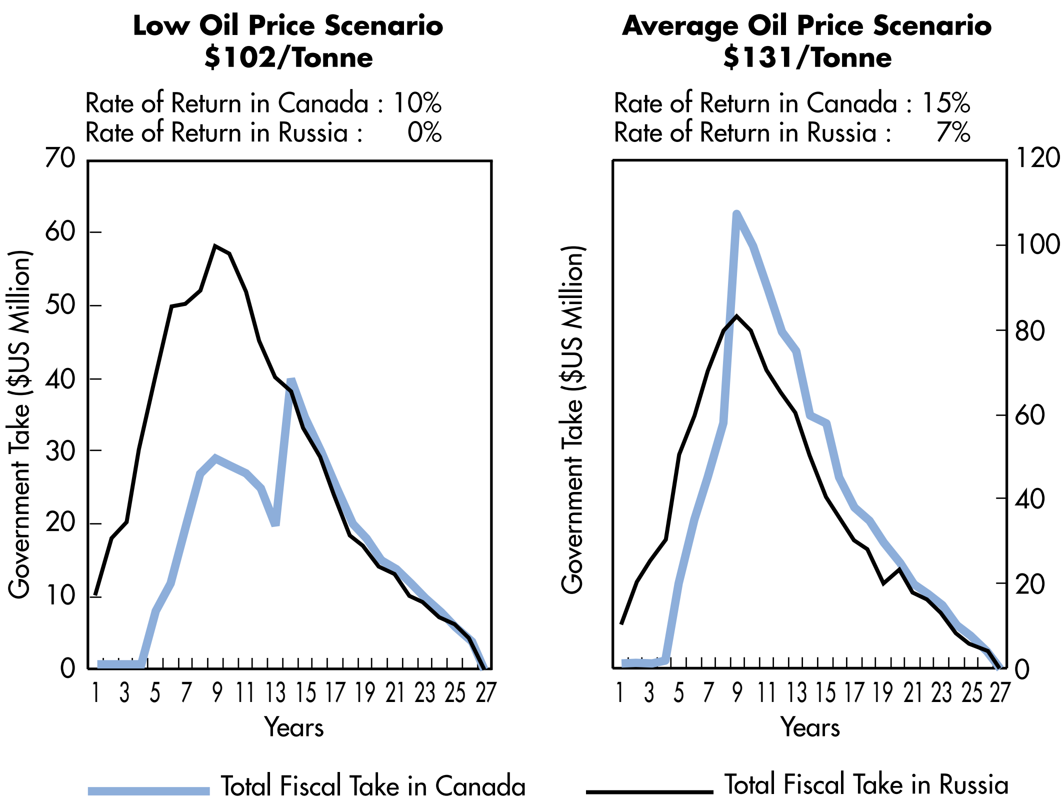
the previous year, varying from 10% when the R-factor equals one, up to 60% when the R-factor equals or exceeds two. The tax rate for blocks that are in an advanced stage of development and whose output is declining is set at zero, however, regardless of the R factor. It is unclear what proportion of Russian oil production would actually incur this tax, 55%-60% of production is commercially marginal at international prices of $15-$18/bbl.

42. The amount of the mineral tax is to be adjusted each quarter, based on monthly trends in prices for dated Brent crude, as compiled by the Ministry of Economic Development and Trade. As originally drafted, the base rate was set at 425 rubles ($15) per ton based on a current price of 4,300 rubles ($152) per ton for dated Brent. The Duma subsequently scaled this back to 340 rubles per ton and kept the excise tax.

Figure 4 Comparison of Government Take and Impact of Fiscal Systems on Project Rate of Return



the right tax structure has particular importance for Russia, where the oil industry has accounted for 20%-23% of Federal government revenues in recent years.[43]

►►► ***Continuing Improvement of the Tax Code.*** *The original approach to oil-sector taxation reform in the Tax Code – a relatively low royalty plus an excess-profit tax, together with the normal corporate profit tax – provided a self-regulating mechanism and a predictable environment for investors. Although streamlined taxation and reduced corporate profit tax rates are positive steps in the tax reform process an overall more profit-based structure of taxation is essential if Russia is to attract long-term investment. This is especially important in the mineral resource sector, where up front costs are significant and payouts are long-term.*

PSA Legislation

Perhaps the single most important legislative thrust has concerned production-sharing agreements (PSA). This form of investment dominates much of the world's oil industry outside the OECD countries, especially in countries only recently open to international investors. A key attraction of the PSA regime for private investors lies in the fact that it replaces energy-specific taxes and eliminates many uncertainties about future tax rates and rules. The division of profits between the company and the state becomes the subject of a contract that extends over the life of the project. PSAs have proven

43. According to a special report prepared by *Neft Rossii* for the *Duma* in 1998, the oil sector provided 6% of budget revenue in 1994, 13% in 1995, 16% in 1996 and 22% in 1997-1998.

attractive to both investors and governments in many countries because the structure rewards the operator for reducing costs while ensuring that the state receives an increasing share of higher profits. In the view of international oil companies, until the overall legal and tax regime is put into place, only a contract-based PSA regime can provide the fiscal and legal certainty and long-term guarantees necessary for large-scale investment in Russia.

Many "mega-projects" in Russia, as well as a host of smaller ones remain contingent upon establishing a workable PSA framework. Although they were long viewed primarily as a vehicle for foreign investment, PSAs are now increasingly recognised as useful to stimulate domestic investment in large upstream projects. To date, however, Russian company support for the PSA framework has depended largely on the state of international oil prices and transfer pricing mechanisms that affect profitability in the short term under the current licensing system. If oil prices fall, if transfer pricing are minimised or if the tax regime worsen again, Russian companies would probably be led to take a longer-term view and see PSAs in a more favourable light. Ironically, much of the delay and caution by Russian officials in completing a workable PSA framework has arisen from fear that Russian companies will abuse it.

Value of PSAs and Some Misperceptions

Investors regard the PSA as a workable mechanism upon which major investments can be based, especially during the period while an overall legal and tax regime is put into place and confidence in it is built. A common misperception is that PSAs reduce a government's sovereignty and control over mineral resources. This is not the case. The license owner must meet the terms of the PSA agreement or the license can be revoked. The PSA however, *does* protect the investor against arbitrary unilateral decisions by the state. Moreover, it is misleading to compare state revenues from PSAs with revenues under the current tax system. Many projects that could flourish under PSAs would not come to life at all under the current system.

Russian legislators and officials hope that the completion of the PSA regime will "unlock the floodgates of foreign investment". The Ministry of Energy estimates that Russia could attract up to $80 billion of foreign investment over the next decade if the PSA mechanisms were properly implemented[44]. Announcements in late 2001 by investors in both the Sakhalin-1 and Sakhalin-2 PSAs pledging to invest a combined $20 Billion over the next seven to eight year period, underscore the importance of effective implementation of the PSA investment framework.

The original Law on Production-Sharing (PSA Law) went into effect at the end of 1995. Because of the many changes and compromises it underwent during the legislative process, however, it was roundly criticised as too diluted. Due to its many internal contradictions and incompatibility with existing laws as well as with the draft Tax Code, an "enabling law" was needed to put it into effect. Amendments to the original

44. Interview with Deputy Minister V.Z. Garipov, Infotek, No. 8, 2000.

Law were also needed. One of its requirements was that all new PSA contracts must receive the approval of the Duma via laws specifying the fields or deposits eligible for development on PSA terms (the so-called "list laws"). These key implementing laws were held up in the Duma from 1996 through most of 1998. In December 1998 the Duma passed a package of amendments to the PSA Law and the applicable individual tax laws, which entered into force in early 1999. The "list laws" passed since 1998 cover 21 fields.[45] Table 4.7 shows the current state of PSA projects.

Changes to the basic PSA Law include a 30% ceiling on the portion of reserves eligible for development on PSA terms. Because the current PSAs nearly fill this quota on oil (26.5%), although not on natural gas (11.2%), discussions are underway on integrating the Law to refer to new fields only, or increasing the quota to 40%. Another amendment imposed a 30% limit on foreign-made equipment used in PSA projects.[46] Still another, in effect since 1999, exempted agreements involving fields with reserves of less than 25 Mt from explicit Duma approval, requiring approval only from the Federal government and the relevant regional authorities. This was an important element in a compromise with regional authorities that established the pre-eminence of Federal law in PSAs, but allowed the regions to conclude PSAs on small fields without separate Federal legislation. Previously, regions such as Khanty-Mansiysk and Tatarstan had passed PSA laws that contradicted Federal legislation.

A key fact demonstrating the limitations of the PSA Law is that not a single new PSA with a foreign investor has been signed and implemented since its passage in 1995.[47] The only PSA projects to have made significant progress have been those signed before its passage.[48] Even so, the implementation problems encountered by the "grand-fathered" Sakhalin-1 and Sakhalin-2 projects highlight the need to streamline and clarify the regulations.

Since the electoral results of 1999-2000 have brought the Duma and the presidency closer together politically, the prospects for completion of the PSA regime may have improved. From 1997 to 2001, the authorised state body for PSA was the Ministry of Fuel and Energy, now the Ministry of Energy. This responsibility moved to the powerful Ministry of Economic Development and Trade (MEDT) in February 2001. Co-ordination of PSA issues, since 1997 the responsibility of a special government commission headed by a Deputy Prime Minister, will now be exercised by the MEDT.

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45. Note that the three "grand-fathered" PSA Projects are not included in PSA list laws.
46. It is still not clear what this means – whether the limit refers to every article or can be applied in aggregate over the life of the project. Investors favour the second interpretation, as it makes economic sense to use Russian equipment and labour to reduce costs. The concern is that some Russian equipment does not yet meet international standards. Investments could be delayed if imported equipment cannot be used instead.
47. A partial exception is the PSA on the Prirazlomnoye offshore field in the Barents Sea. A memorandum on this project was signed between Germany's *Wintershall* and *Gazprom* on 15 June 2000 during a visit by President Putin to Germany. But a PSA still has to be signed between the two investors and the Russian government.
48. Even a PSA signed with a domestic investor (*TNK*) has stalled. A PSA agreement on the Samotlor oil field, a field in production for over 30 years, was signed on 24 December 1999 by *TNK*, the Federal government, and the Khanty-Mansiysk administration. Yet it cannot be implemented due to numerous conflicts with other laws and regulations, such as its provision for 100 percent exports. To break the legal bottlenecks, *TNK* has proposed a simplified alternative version of the PSA law that establishes a straight negotiated split of physical production between the developer and the state. Such an arrangement would be totally unacceptable to foreign investors, however, due to the implications it could have for double taxation.

Table 4.7 Russian PSA Projects: Implemented or Authorised

Fields/projects	Location	Russian Partner	Foreign Partner
1. "Grandfathered" projects (signed before adoption of PSA Law)			
Sakhalin-1	Sakhalin Oblast (offshore)	Rosneft, Sakhalinmorneftegaz	ExxonMobil, Sodeco
			ONGC (of India), Rosneft
Sakhalin-2	Sakhalin Oblast (offshore)	–	Sakhalin Energy
			(Shell, Mitsui, Mitsubishi)
Khar'yaga (Horizons II and III)	Nenets Okrug	LUKoil, Nenets Oil	Totalfina-Elf, Norsk Hydro
2. Authorized projects (by PSA List No. 1)			
Prirazlomnoye	Barents Sea	Rosshelf, Gazprom	Wintershall
Samotlor	Khanty-Mansiysk Okrug	TNK, Nizhnevartovskneftegaz	–
Krasnoleninskoye	Khanty-Mansiysk Okrug	TNK, TNK Nyagan (Kondpetroleum), Yugraneft	–
Romashkino	Tatarstan	Tatneft	–
Northern Sakhalin	Sakhalin Oblast	Rosneft, Sakhalinmorneftegaz	–
3. Authorized projects (by other PSA List Laws)			
Salym group	Khanty-Mansiysk Okrug	Evikhon	Shell
Usinsk	Komi Republic	LUKoil	
S. Lyzhskoye, N. Kozhva (Bl.-15)	Komi Republic	Parmaneft	–
Udmurt block	Udmurt Republic	–	
Yurubcheno-Tokhomskoye	Evenk Okrug (Krasnoyarsk Kray)	East Siberian Oil	–
Uvat block	Khanty-Mansiysk Okrug	Uvatneft	–
Federovo	Khanty-Mansiysk	Okrug Surgutneftegaz	–
Luginets	Tomsk Oblast	Tomskneft (VNK/YUKOS)	–
Sakhalin 3 – I Kirinskiy block	Sakhalin Oblast offshore	Rosneft, Sakhalinmorneftegaz	ExxonMobil, Texaco
Sakhalin 3 – II Ayyash / East Odoptu	Sakhalin Oblast offshore	Rosneft, Sakhalinmorneftegaz	ExxonMobil
Northern Territories block	Nenets Okrug	LUKoil, Arkhangelskgeoldobycha	Conoco
Tyanskoye	Khanty-Mansiysk Okrug	Surgutneftegaz	–
Vankor	Krasnoyarsk Kray	Yeniseyneft	Anglo-Siberian
Kharampur	Yamalo-Nenets Okrug	Rosneft, Purneftegaz	–
Komsomol'sk	Yamalo-Nenets Okrug	Rosneft, Purneftegaz	
Priobskoye	Khanty-Mansiysk Okrug	YUKOS	–
Kovykta	Irkutsk Oblast	RUSIA Petroleum	BP Amoco, EAGC (Korea)

Investors hope that this bureaucratic streamlining will hasten completion of the PSA regime, including passage of "normative acts" to interpret and flesh out the PSA Law and adoption of the PSA chapter of the Tax Code. Potential investors still view the Cost Recovery and Abandonment acts signed by the Prime Minister in July 1999 as inadequate. Key normative acts that are still needed include amendments to the Cost

Recovery and Abandonment acts and new acts on implementation, commercial discovery, the procedure for the exemption from VAT, accounting and reporting, customs, currency and banking and various tax-related instructions. One existing provision of the PSA law is particularly worrisome to foreign investors. It allows the government to revise the terms of a PSA unilaterally in the event of an undefined "substantial change in circumstances".

►►► ***Completion of the PSA Regime.*** *One of the most important reforms needed to quickly improve the investment climate is the completion of a comprehensive, clear and stable legal framework for petroleum licensing and operations, for both Russian and international companies. Key tasks are passage of the normative acts and the PSA Chapter of the Tax Code. Further amendments to the PSA Law will also be required.*

Foreign Investment

The dominant vehicle for foreign direct investment (FDI) in the Russian oil sector has been the joint venture (JV). The first oil under production-sharing contracts was obtained in 1999 from two projects, Sakhalin-2 and Kharyaga. The Sakhalin-2 project became operational in 1996, and investment since then has totalled $1.25 billion. Total investment in the Kharyaga project has been about $100 million since its starting date in January 1999. The Sakhalin-1 project is still a year or two away from production, with investment totalling about $250 million since its implementation in 1996. "Commercial" production is slated to commence in 2003. Over the 20-year lives of these projects, Sakhalin-1 will require an estimated $13 billion in investment, Sakhalin-2 about $10 billion and Kharyaga about $700 million.

Cumulative FDI in the upstream oil sector reached about $4 billion by the end of 2000, a fraction of the enormous immediate financial needs of the sector. FDI did rise significantly in 1999, however, to $1.2 billion, after hovering at between $200 and $300 million since 1994. About $350 million of the 1999 total was invested by PSA projects. FDI then dropped back to $441 million in 2000. This decline reflects the limited number of PSA projects in the implementation phase and the nature of their project cycles. Despite their improved financial status, most JVs did not significantly increase investment outlays in 2000. New projects have moved only slowly and many existing operations are still reluctant to expand. It will take sustained and consistent efforts by the Russian government over a considerable period to convince international companies to invest sizeable sums.

Potential and actual investors have explained the relatively small amount of foreign investment in the sector by the high level of uncertainty and political risk, focusing on a number of problems, including notably:

- the absence of a stable and competitive legal and fiscal framework;
- uncertainties about property rights and rights to mineral resources;
- the uncertain tax system that targets revenues instead of profits;
- export controls that restrict access to international markets;
- pricing policies that maintain a wide disparity between internal and external prices for oil.

CRUDE OIL TRANSPORTATION AND EXPORTS

Russia's Crude Oil Pipeline System

Reflecting Russia's continental character, pipelines dominate crude-oil transportation. Only small amounts of crude move in other ways, mostly by rail to supply refineries in the Far East not on the main pipeline system. An increasing amount of crude does move to various export points by rail to get around both physical bottlenecks in the pipeline system and government-imposed administrative restrictions.

Transneft operates the trunk pipeline system. By the end of 1999, the system extended approximately 46,700 km (reduced slightly since 1990) and included 867 oil storage tanks with a total capacity of 12.8 million cubic meters. Storage capacity in the transport system is fairly limited and is capable of holding only about two Mt, or about two days' production. According to Goskomstat, 282.1 Mt of crude was moved in Russia's pipeline system in 1999 and 294.6 Mt in 2000 (Table 4.8); Transneft' reports that it moved a total of 314.8 Mt. Of the 2000 total, 124.1 Mt (39.8%) was shipped to export destinations outside the territory of the former Soviet Union (FSU), including 112.4 Mt of Russian crude and 11.7 Mt of transit crude from Kazakhstan, Turkmenistan and Azerbaijan, plus another 0.35 Mt to Poland from Belarus.

Table 4.8 Oil Shipments by Pipeline in the RF 1990 to 2000, in Million Tonnes

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Crude oil	497.9	441.4	382.8	335.4	299.5	287.9	281.5	283.8	282.0	282.1	294.6
Refined products	60.2	55.1	40.5	26.1	18.3	20.9	20.4	22.1	20.9	20.9	23.1

The FSU pipeline network has a total length of about 62 000 km, making it the largest integrated system in the world. It is characterised by a high degree of parallelism, particularly in its Russian core. It interconnects with 17 countries, including Russia, Ukraine, Kazakhstan, Belarus, Lithuania, Latvia, Uzbekistan, Turkmenistan and Azerbaijan in the FSU, and Germany, Poland, the Czech Republic, Slovakia, Hungary, Slovenia, Croatia and Yugoslavia (Serbia) outside the FSU. The system also provides access to other international markets via large marine terminals on the Black Sea (Novorossiysk, Tuapse, and Odessa) and on the Baltic Sea (Ventspils, Butinge, and Gdansk).

The system's general operations, including movement and off-take of crude, have changed little since the Soviet era. The pipeline does not segregate crudes, so that the mixing and blending that occur during pipeline transport produce a generic "Export Blend". There is no system of compensation between shippers for differences between the quality of crude put into the system and that delivered (*i.e.* a "quality bank"). Such a system would not only be important for individual producers, but would also send the correct signals to producers about the relative values of different types of crude. It could also potentially yield higher average quality crude at export points than does the current blend. If an appropriate system of compensation were established, low-quality crude producers would no longer have the incentive to inject their oil into the general export flow and could find it more rewarding financially to re-orient their output towards specialised local refineries.

►►► ***Establishing a Crude Oil Quality Bank.*** *As is the case in the CPC pipeline, a quality bank would provide compensation to shippers for the differences in quality (and therefore value) between the crudes injected and lifted. Initially this could be done for exports, then extended to domestic shipments.*

A major concern for Russia's oil pipeline system is the condition of the network due to its age, which has a direct correlation with accidents and reliability. Corrosion causes almost a third of all incidents on the Russian trunklines, and most repair efforts relate to problems stemming from soil corrosion. In 2000, 73% of Russian oil pipelines were over 20 years old and 41% over 30 years old. Nevertheless, Transneft reports that its accident rate is declining and was 13% lower in 1999 than in 1998. It would appear that reduced throughput in the 1990s, as well as more repairs and upgrades, have helped to reduce accidents. As rising oil output puts increasing stress on the system, however, accidents may become more frequent. The most vulnerable part of the system is probably in the oil-field gathering lines operated by oil producing companies, rather than the main pipelines operated by Transneft.

Pipeline Regulation and Access Issues

Transneft is nominally a regulated fee-for-service carrier. The Law on Natural Monopolies and other, secondary rules and procedures require it to offer equal network access to all accredited shippers and to charge non-discriminatory tariffs. In the event of constrained pipeline capacity, current rules call for pro-rationing based on the previous quarter's production. Since 1998, however, the government has also made access to the pipeline system contingent upon meeting assigned domestic delivery quotas and payment of all tax obligations. It has also offered "supplementary" exports (as "free" capacities arise during the operation of the system) to selected producers based upon a point system that weights output growth, investment outlays, quality of reserves, and other factors.

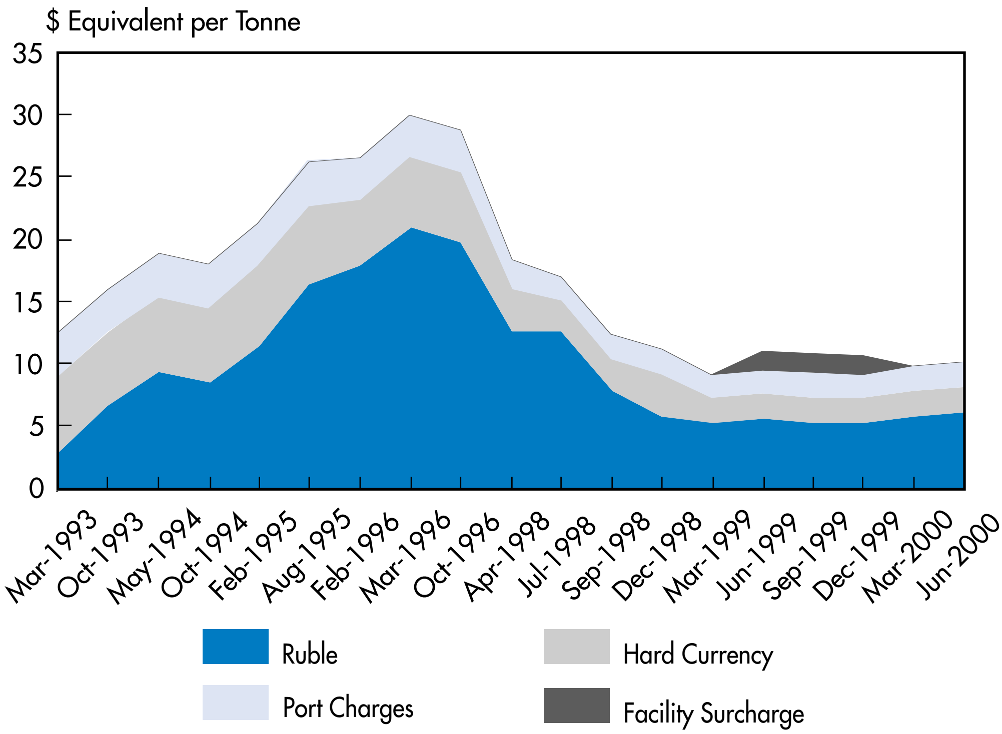
The FEC regulates Transneft's tariffs. The Commission for Oil and Gas Pipeline Use, established in November 2000 to replace the Inter-Departmental Commission (see below), regulates export access. With regulatory responsibility for the oil and gas trunklines, oil terminals and ports, it is charged specifically with establishing non-discriminatory conditions for all shippers. Its main functions include reviewing the quarterly balances developed by the Ministries of Energy and of Economy and Trade that establish export volumes and domestic deliveries, which ensure sufficient energy for domestic needs. It also sets quarterly schedules of oil shipments.

Transneft manages the operation of the crude pipeline system on the basis of monthly schedules approved by the Ministry of Energy's Central Dispatch Administration. The basic tariff methodology is a forward-looking, cost-based model, with prices set to recover a targeted revenue requirement based on the costs (including profits and taxes) of meeting planned levels of operations. Tariffs are reviewed periodically to adjust for rising costs due to inflation. Figure 5 shows trends in average tariffs. In January 1999 Transneft introduced a two-tier tariff with both a capacity charge (per tonne) and a pumping charge (per tonne-km).

►►► ***The independent regulator should establish a transparent tariff-setting methodology based on costs.*** *The government should strengthen the independence of the Federal Energy Commission by streamlining/merging the functions of the FEC, the Commission on Oil and Gas Pipeline Use and the Central Dispatch Administration. The independent regulator should establish a transparent tariff-setting methodology based on costs (including a reasonable profit for re-investments, taxes and maintenance). It should also increase predictability of tariff changes by requiring regular reviews of pipeline costs and revenues.*

Transneft's regular rouble tariffs increased about eight-fold on average between 1992 and 1996 in dollar-equivalent terms. By March 1996, the total transport cost for moving one tonne of crude from West Siberia to the Novorossiysk export terminal had reached over $30 per tonne, or 24% of the value of the exported oil. As international oil prices plunged to record lows in 1998, export margins on Russian crude dropped sharply. In response, the FEC reduced transportation charges. With the devaluation of the rouble after August 1998, pipeline tariffs dropped substantially in dollar- equivalent terms. By March 1999 exports' dollar-equivalent costs fell to one-third of those a year earlier. Pipeline tariffs have since risen again, reflecting higher operating costs and higher crude prices. As in the past, changes in pipeline tariffs appear more closely tied to the value of the crude and the ability of oil companies to pay than to costs of operation. Moreover, the government finances major construction efforts such as the Chechnya bypass and the Baltic Pipeline (see below) through a special tariff levy on all shippers; their readiness to pay "patriotic" tariffs for such strategic systems is likely to last only as long as oil prices remain high.

Figure 5 Trends in Average Pipeline Tariffs* 1993 to 2000



* All tariffs are for identical pipeline routing: Tarasovskoye (in northern West Siberia) to Novorossiysk. The timeline shown indicates when tariff changes actually occurred.
Source: PlanEcon

►►► ***Elimination of Investment Levy.*** *New pipeline systems serving a regional crude stream (such as the Baltic Pipeline or the extension to the Yurubcheno block in East Siberia) should not be financed through a general tariff levy, but largely equity-financed by future shippers.*

Crude Oil Exports

Russian Crude Oil Trade with the Other Former Soviet Republics

Crude oil shipped to the rest of the FSU has declined dramatically since the break-up of the USSR. These exports fell 81.9% between 1991 and 2000, to only 21.2 Mt. A combination of factors contributed, including a decline in demand associated with a contraction in economic activity, financial difficulties in the refining sectors of the republics, and a breakdown in inter-republic trade and payments mechanisms.

In 1992-2000 Russia rapidly increased prices charged in inter-republic trade, towards those prevailing on the world market. By 1997, before the severe slump in international prices, Russian exporters charged an average of $105 per tonne for crude oil, compared with $122 received in the international market. The importing republics quickly built up large payments arrears, causing Russia to withhold supplies and divert them to hard-currency markets. Because of this leverage, non-payments by the importing republics for oil have remained relatively modest in comparison with those for natural gas or electricity.

Table 4.9 Russian Crude Oil Exports, 1988 to 2000, in Million Tonnes

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Total exports	257	263	220	174	142	128	127	122	126	127	137	135	143
Foreign	124	103	99	57	66	80	89	91	103	106	112	112	126
Other republics	132	160	121	117	76	48	38	31	23	21	25	22	17

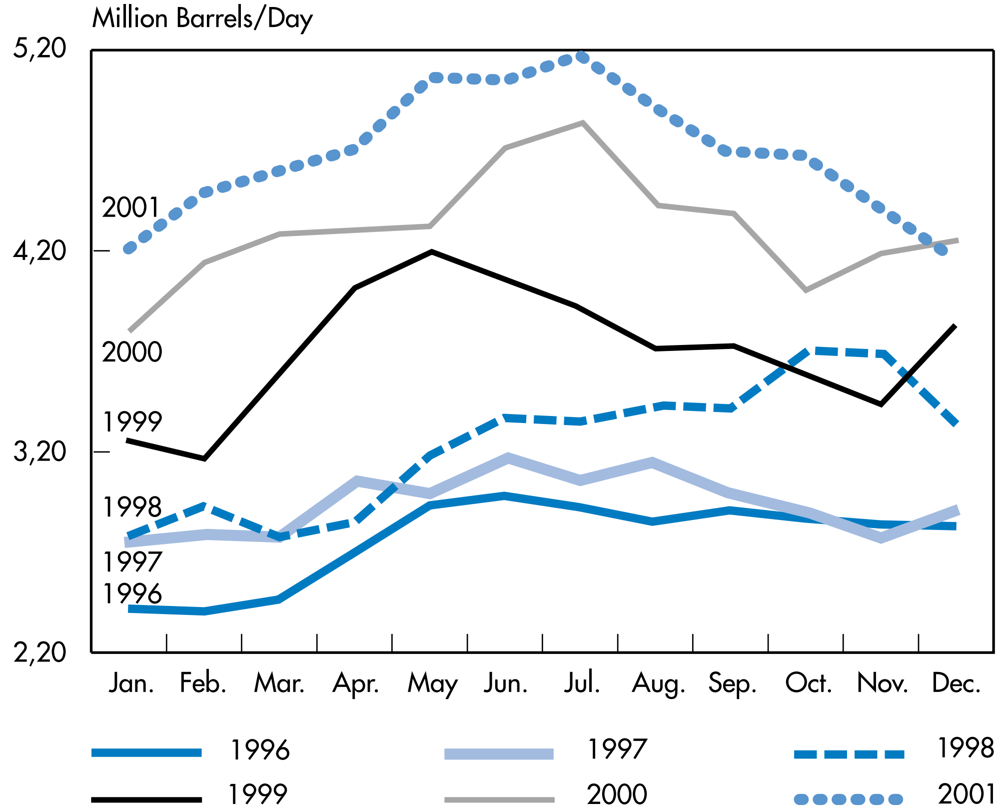
Source: IEA estimates and statistics; Ministry of Energy, 2001.

Foreign Crude Oil Exports

In the late 1980s, the USSR was the world's second largest oil exporter after Saudi Arabia, with annual net oil exports (crude and products combined) between 155 Mt and 185 Mt (3.1-3.7 million barrels per day), most of it Russian oil. The USSR also re-exported Middle Eastern oil received as payment for the sale of arms and other commodities. Russia's international exports of crude oil contracted by 45.4%, from 124.4 Mt in 1988 to only 56.5 Mt in 1991, when the government met virtually the entire drop in domestic crude production with a reduction in exports. International exports then began to rise in 1992, reaching 125.5 Mt in 2000 despite administratively imposed limits.

Like Mexico and the North Sea, the FSU is a major source of non-OPEC oil for Western countries. As well as showing the seasonal trend of FSU exports, Figure 6 reflects the dramatic increase in FSU exports (over 90% from Russia in 2001) from 2.76 million barrels a day (mbd) in 1996 to 4.32 mbd in 2000 and to average 4.72 mbd over the first three quarters of 2001. Russian oil has been a welcome addition to the West European market, helping to diversify sources from too great a reliance on the Gulf region and OPEC. Most West European countries purchase oil from Russia, although it is usually less than 10% of national oil supplies. The largest customers have been

Figure 6 FSU Exports of Oil and Oil Products in Million Barrels / Day, 1996 to 2001



Source: IEA Statistics.

Germany (especially with the addition of eastern Germany), Italy, France, Finland and the UK. More recently, Switzerland and Ireland have also joined the group.

Export Policies: Export Quotas, Special Exporters, Export Taxes, Export Auctions

Because of the initial wide price differential between international and domestic markets – and the desire to preserve it to cushion domestic consumers – the government restricted oil exports with quotas until 1995. Along with the quota system, so-called "special exporters" helped the government in monitoring export shipments. Principally trading companies, they were the only legally authorised export entities, acting as agents for producers in meeting their export quotas.

The liberalisation of oil exports was a key commitment to the international financial institutions (IMF, World Bank) in Russia's loan agreements at the outset of the economic reform program. Initially set for May 1994, it was delayed until April 1995, when a presidential decree fully relaxed foreign trade, disbanded the special exporters and scrapped the many tariff concessions for selected enterprises and regions. The new system assigned pipeline access in proportion to production along segments where capacity was constrained. It also provided for the free transfer or sale of pipeline access rights, essentially creating a market for pipeline access. With the ending of the quota system and licensing in 1995, the export tax became the main policy instrument for controlling export volumes and regulating internal prices. Initially introduced in January 1992, it served essentially as a wedge between domestic and international prices. Under a 1995 agreement with the IMF, the tax was progressively reduced and finally abolished in July 1996.

A system of mandated domestic deliveries for both crude and refined products, introduced in the crisis year 1998 and still in place, basically reduces companies' crude export access unless they deliver specified amounts to domestic refineries, determined by the quarterly material balances developed by the Ministries of Energy and of Economy and Trade.

In a renewed attempt to control oil exports, the Ministry of Energy created a system of oil export "co-ordinators" in mid-July 1995. It assigned a single oil company to co-ordinate all oil exports through each export point. The export co-ordinators also received power to negotiate crude export prices. But the system had drawbacks. It was not transparent and inhibited individual shipper initiative in putting together innovative deals. It was eliminated with the formation of the Commission on Oil and Gas Pipeline Use in November 2000.

The government later announced plans to introduce an auction system for export quotas in the second quarter of 2001. Such a system has long been advocated by the IMF, among others, as a transparent way of allocating a "scarce" commodity, namely Russia's limited export capacity to international markets. The auctions will be introduced under the auspices of the Commission on Oil and Gas Pipeline Use[49], headed by Deputy Prime Minister Viktor Khristenko. Under Khristenko's plan, the oil companies will bid for quotas at an open auction, with the proceeds going to the Federal budget. He is pushing for the auctions to "end the abuses" of the current system, particularly the noticeable differences among companies in the proportions of production they export.[50]

There is a concern that such a scheme could institutionalise the official administrative limits on exports as well as the large gap between international and domestic prices. Because the amount bid for export access would be driven by the size of the price gap, the government could have an incentive to keep the gap as wide as possible. In effect, the additional cost for export access would function like the export tax, as a wedge between domestic and international prices. Another drawback lies in the actual mechanics of the auction. If individual allotments are fairly large, they become less attractive to smaller and mid-size producers. At an auction a company could be left without export quotas and correspondingly without a market for its product and a large

49. The now-defunct Inter-Departmental Commission, which the new Commission replaces, was established in 1994 to monitor pipeline use, design quarterly export timetables, ensure priority access under inter-governmental agreements and state contracts and monitor supplies of oil and products to the domestic market. The 17-member Commission on Oil and Gas Pipeline Use co-ordinates the Federal organs that oversee the supply of energy resources. Its stated aims are to create non-discriminatory conditions for access to pipelines and terminals, storage and transport and sale of oil and gas; to improve foreign trade operations; and to represent the interests of the state, producers and energy consumers.

50. In theory, all companies should be allowed to export about 30% of their production, but those with greater lobbying power have been able to increase their export access. This resembles the situation that prevailed under the export quota system of 1992-1995. It has occurred as the rules relating to exports have become more arcane and bureaucratic since 1998 (*e.g.* due to the material balancing procedure developed by the Ministries of Economy and of Energy that determine domestic delivery requirements and export volumes, tax compliance, export access and supplemental quotas).

part of its income. Most worryingly, two or three large companies could lock up all of the export access offered, which they could later re-sell to less successful bidders. This would be disadvantageous for emerging small and mid-sized oil companies.

►►► ***Export Auctions.*** *The relatively simple method of pro-rationing exports according to production volumes for the previous quarter that prevailed in 1996-1998, seems more equitable than the newly proposed system. This appears to have a number of drawbacks that could prevent it from ensuring equal access to crude exports on a transparent, non-discriminatory and competitive basis.*

State Exports

Although state exports were abolished in July 1997 as part of an agreement with the IMF, they reappeared in 1999 and continued through 2001. State exports are used to fund special projects. Under this programme, a fixed volume of export capacity is allocated to designated government agents who buy oil from producers at low domestic prices and sell it at export prices, sharing the proceeds of the transaction with the government.

Export Routes and Terminals

The bulk of Eastern Europe's oil from the FSU is delivered via the Druzhba Pipeline. Exports to northern European countries such as Finland, western Germany, the Netherlands, Britain, and Belgium are mainly shipped out of Ventspils in Latvia, although some also moves through Gdansk, Poland, and Butinge, Lithuania. Russian oil also is shipped out of Estonian terminals, where it arrives by rail. Mediterranean markets such as Italy, Greece, Spain and France are reached via the Black Sea ports of Novorossiysk and Tuapse in Russia, as well as the Ukrainian port of Odessa. International crude exports in 2000 included 124.4 Mt[51] shipped through the main Russian pipeline system operated by Transneft. Another 10.8 Mt[51] went by other routes, including rail. Additional tanker shipments included 672,100 tonnes exported by the Sakhalin-1 project directly from its offshore platform; 1.5 Mt by Sakhalinmorneftegaz via the DeKastri terminal in the Far East; about 700,000 tonnes by Kaliningradmorneftegaz (virtually all of its production) out of a terminal in Kaliningrad’s Baltic port; and about 100,000 tonnes from a terminal on the Barents Sea island of Kolguyev.

Of the 124.4 Mt of export shipments handled by Transneft in 2000, 70.5 Mt (57%) went through the major marine terminals, while 53.9 Mt (43%) went via the Druzhba Pipeline (see Map 2). In 2000, the amount dispatched through these ports represented about 89% of their overall rated capacity. Utilised capacity was about 76% at Ventspils, 96% at Novorossiysk, and over 100% of rated capacity at both Tuapse and Odessa. There is little capacity to export additional oil through the major ports, except perhaps via Ventspils and Butinge. Volumes through Ventspils are being cut back because of sizeable port fees. The Russians hope to achieve tariff concessions by deliberately fostering competition between Ventspils and Butinge.

The new Butinge terminal added another eight Mt of annual marine export capacity to the FSU pipeline system in mid-1999, dispatching 550,000 tonnes of Russian crude in the second half of 1999 as well as handling some imports for the Lithuanian refinery. In 2000, Russia exported 3.1 Mt via the Butinge terminal.

51. Includes transit oil.

Novorossiysk is the FSU's largest marine terminal, handling 37.4 Mt of crude in 2000, including 34.9 Mt of Russian, 0.6 Mt of Azerbaijani, 1.7 Mt of Kazakh and 0.2 Mt of Turkmen crude. It continues to handle slightly more each year, but the terminal is close to full capacity despite additions made in 1999-2000. Although Odessa is the most expensive of the major export points due to both high port fees and significant pipeline transit costs across Ukraine, utilisation remains high. The Russians have directed over 70% of Kazakhstan's total pipeline allowance for shipment through the Russian pipeline system to this terminal.

Utilisation of the Druzhba Pipeline rose to 90% in 2000, although only Germany and Poland increased their purchases. Germany has steadily increased its crude off-take due to expanding demand from the new Leuna refinery. When it went into operation in 1997, shipments to Germany's Rostock marine terminal on the Baltic ceased. At the Belarus-Poland border, the Druzhba has two strings with a rated capacity of 35 Mt per year. The northern one is now fully used and any further increases in refinery demand in Poland or eastern Germany will have to be balanced by reduced trans-shipment to Gdansk. A total of 1.99 Mt was reportedly shipped out through Gdansk in 2000.

While the southern arm of the Druzhba still has available capacity (it moved only 15.3 Mt of its 25-Mt capacity in 2000), flows have been declining the last few years. This reflects not only reduced aggregate crude demand in the importing countries, but also the switch by Czech refineries to lighter, high-quality crudes brought in from the Mediterranean through the IKL Pipeline *via* Germany. Russia would like to make greater use of the southern Druzhba's capacity by transferring volumes into the Adria Pipeline to the Adriatic.

Exports by Foreign Oil Producers

Export access has always been a major concern for producers, especially the joint ventures. Citing constraints in export capacity, Russian pipeline and foreign trade authorities first imposed export quotas and a number of other procedures in 1993-1995. The situation changed following the imposition of the new export regime in March 1995, when 13 JVs received priority access to export pipelines under promises made earlier to them. The other JVs operated under the pro-rationing system. In 1998 all producers, including foreign ones, came under the limitations imposed by the domestic delivery requirements. In 1992, JVs exported 84.6% of their output, then only 46.1% in 1993 following the first clampdown. In aggregate volume, JV exports peaked in 1998 at 12.6 Mt, 11.3% of Russia's total non-FSU crude-oil exports that year. In 1999, JV exports dropped to 8.5 Mt, only 42.5% of production and 7.6% of total Russian non-FSU crude-oil exports; in 2000, JV exports dropped further, to 7.7 Mt, representing only 37.2% of production.

Emerging Export Bottlenecks

Due to the precipitous decline in crude-oil production in the first half of the 1990s, total flows in the oil pipeline system are now much smaller than before. Shipments declined by 43.5% between 1990 and 1996, from 497.9 Mt to 281.5 Mt, and even by 2000 had only risen to 294.6 Mt. Nevertheless, crude-oil pipelines continue to experience significant bottlenecks. Key constraints occur at the ports and the pipelines supplying them, particularly at Novorossiysk, Russia's major oil-export port on the

Black Sea. The constraints occurred because a large portion of the total crude flow once went to refineries across the former USSR, and a substantial amount flowed to Eastern Europe via the Druzhba Pipeline. With the dramatic decline in oil demand in the former Soviet republics and Eastern Europe, a much larger proportion of the total flow has become focused on the few ports dispatching crude to the other international markets. Because the FSU pipeline system was designed mainly to move crude to internal consuming centres, much of the core system in the interior of Russia now has significant redundant capacity.

The escalation in tariffs and the wide variation in port fees, transit charges and hard currency tariff rates among the different export routes have also caused considerable differentials in transport charges for crude. The relative differentials have also shifted over time. Some reflect the degree to which transit states and ports have been able to generate monopoly rents because of limited competition between export routes. All result in wide differences in netbacks to producers from their export sales, depending upon export routes. Decisions on which markets and routes are used are taken by those who determine export access, not the producers. More effective competition between routes may narrow the differentials as monopoly rents are eliminated.

►►► **Transneft *should function merely as a service provider.*** *The government practice of using* Transneft *as a mechanism for controlling developments in the oil sector in the wake of its fragmentation, commercialisation and privatisation should end. Control over access to export markets has allowed certain players, such as ports, the government and transit states, to capture monopoly rents.*

Projects to Expand Export Capacity

The proposals to expand export capacity with new terminals on Russian territory generally are fairly expensive solutions. In contrast, several projects to increase use of the Druzhba Pipeline into Eastern Europe are relatively low-cost but probably more difficult politically (see Map 3).

The **Caspian Pipeline Consortium** (CPC) is one of the most important projects that could significantly free up export capacity. Founded by Kazakhstan, Russia and Oman in June 1992, the CPC was established to build a dedicated export pipeline for Kazakh crude to the Black Sea. Although primarily for handling Kazakhstan's expanding oil exports, it also has several important implications for Russia, not only in terms of physical capacity, but also institutionally, as it is the first major international pipeline project to be executed in Russia.

After long delays, in part due to reluctance on the part of Kazakh producers to ship oil through a pipeline they did not own, a compromise agreement signed in December 1996 brought in a number of companies as shareholders. Stakeholders in the project now include the governments of Russia, Kazakhstan and Oman, with 24%, 19% and 7%, respectively. The remaining 50% is split among Chevron (15%), LUKoil/Lukarko JV (12.5%), Rosneft/Shell (7.5%), ExxonMobil (7.5%), British Gas (2%), ENI (Agip) (2%), Kerr-McGee (Oryx) (1.75%), and Kazakhoil/BP Amoco (1.75%). The oil companies agreed to provide 100% of the financing in return for profits equal to their respective stakes.

The CPC's pipeline, operated by an independent company, uses an existing 1020-mm pipeline from Atyrau, Kazakhstan, to the Komsomolsk pumping station in Russia. The project also includes construction of a new pipeline extension from Komsomolsk to a new marine terminal near Novorossiysk. It has an initial capacity of 28.2 Mt per year. This first phase is estimated to cost $2.4 billion, rising to $4.2 billion by 2015 as capacity is added, ultimately to reach 67 Mt per year. The first phase was completed in November 2001. While the pipeline and terminal provide a significant expansion of export capacity for the region, it will probably not be available to non-shareholders, as 100% is already allocated among the consortium members. The bulk is reserved for production from Tengiz, although Russian producers will have an allocation of 8 Mt in the first phase.

Baltic Pipeline Systems. The Baltic Pipeline project involves construction of a pipeline extension and a new marine terminal at Primorsk, near St. Petersburg, to serve as an outlet for up to 40 Mt of crude from the Timan-Pechora fields. Russian producers have been penalised by the high transit and port fees charged by Latvia on oil exported via Ventspils. Russia's policy is to free itself from over-dependence on individual transit states, in part by developing competing capacity to establish greater negotiating leverage. However important the project may be in terms of export diversification, it appears to have some economic difficulties, not least because the Primorsk site is ice-bound for some six months of the year.

The first phase of the project, estimated to cost $460 million, will reconstruct part of the Yaroslavl-Kirishi pipeline, lay a new pipeline from Kirishi (the existing terminus of the Transneft pipeline system) to Primorsk and construct an oil terminal there. This will provide an initial export capacity of 12 Mt. Plans to boost it to 30 Mt by 2003 would require a more ambitious construction programme, including pipeline looping projects extending back to Usinsk and even Kharyaga. Financing will come from a special facilities surcharge tacked onto the regular Transneft tariff, which means that all shippers would help pay for the construction of Primorsk whether they use it or not. Work on the project began in May 2000, with the first phase scheduled for completion by the end of 2001.

The **Northern Gateway** proposal is also intended to handle increased exports from Timan-Pechora, making it a potential competitor with the Baltic pipeline. Initially backed by a consortium of international companies with production interests in the Timan-Pechora region, it involves construction of a new oil terminal on the Barents Sea, which would enable producers in the region to bypass the Transneft system altogether and export directly to international markets. The project also attracted the support of LUKoil, *Arkhangelskgeoldobycha*, and the administrations of Nenets Autonomous *Okrug* and Arkhangelsk *Oblast*. LUKoil has also proceeded on its own with the construction of a new one-Mt per year oil terminal at Varandey, where the first tanker was loaded in August 2000. As production increases, capacity will expand to 5.0-6.5 Mt per year and eventually to 15 Mt per year.

Four possible options for a larger pipeline system and terminal have been proposed, entailing significant capital investment as well as major technical challenges.

Construction cost estimates vary from $1.8 billion to $3.3 billion for projected capacities of 15-50 Mt per year. Most would require ice-strengthened/ice-breaking shuttle tankers and an offshore trans-shipment point to larger tankers somewhere along the Kola Peninsula.

The principal advantage of the Northern Gateway for Russia is that it could provide a large tanker-capable facility on Russian territory, making it possible to reach international markets directly, and provide cheaper access to traditional markets in Northwest Europe. The main disadvantages include major environmental risks and, as the project is currently conceived, export opportunities limited to production from the Timan-Pechora Basin.

Druzhba Extensions. Several potential projects are available to increase use of the Druzhba Pipeline. Most are relatively inexpensive and would require little new construction. Their difficulties relate primarily to the need for co-operation among several governments in each case. One option under consideration would reverse the flow in the now idle Adria Pipeline to reach the Adriatic Sea[52] at the existing Omisalj terminal. Another proposal involves a 100-km connection between the Slovnaft refinery in Bratislava, Slovakia, and OMV's Schwechat refinery near Vienna.

Ventspils Expansion. Latvia has developed a project to increase oil export capacity at Ventspils. According to Latvian officials, this project, known officially as the Western Pipeline System or RCS, would be far more cost effective than the proposed Baltic Pipeline System, and require smaller initial investments ($120 million) in port, terminal, and pipeline facilities. Russia rejected this option for energy-security reasons, *i.e.* to have a Baltic export facility on Russian territory.

Siberia-Pacific Ocean/China. Various proposals exist for transporting oil from West Siberia eastward, for export either *via* Russia's Pacific Ocean port of Nakhodka or to China. Their key constraint is cost competitiveness given the long distances involved. A new pipeline to China or the Pacific would have to be added to the existing 2,121 km from West Siberia to the terminus at Angarsk, near Irkutsk.

Eastern Ukraine Bypass. A high-priority project not necessarily designed to expand export capacity is a crude-oil pipeline to bypass eastern Ukraine. Currently, the main flow of Russian exports to Novorossiysk must transit 364 km through Ukrainian territory. The Ukrainians charge $2.35 per tonne for this transit, about 2.5 times the average tariff levied within Russia; Russian shippers pay about $70 million annually to Ukraine for this transit. Having failed to negotiate lower tariffs, Russia constructed a 252-kilometer bypass to allow the export flow to remain entirely on Russian territory. Known as the Sukhodolnaya-Rodionovka oil pipeline, this 1,020-mm line has a capacity

52. The Adria Pipeline, built in the mid-1970s to bring Middle Eastern oil into former Yugoslavia, former Czechoslovakia, and Hungary, became largely redundant after the oil price shocks rendered large imports of oil from the world market into the East Bloc uneconomic. It received another lease on life in 1990-1991, when the Czech Republic, Slovakia, and Hungary began to diversify their sources of crude away from the USSR. The Adria's inland connections were idled again with the outbreak of conflict in the former Yugoslavia in September 1991. The Adria pipeline has a capacity to move 5-6 Mt annually between Slovakia and Hungary.

of 37-40 Mt per year and an estimated construction cost of $112 million. Transneft built and financed the project itself.

►►► ***Encouraging Commercial Solutions to Export Constraints.*** *Commercial solutions to export constraints could be encouraged by the government by ensuring a stable regulatory framework and streamlining the regulatory and bureaucratic processes to ensure effective project implementation. Also recommended is pipeline legislation providing for long-term contracts so that producers may be able to secure long-term access at predictable rates, open entry to build and operate pipelines and the right to inter-connect to the existing system.*

Transit Issues

The crude pipeline system in the FSU continues to operate more or less as an integrated whole. A system of tariffs and transit fees has been agreed among the states, although some difficulties remain, notably between Russia and Ukraine. Such agreements have continued to provide Russia with access to the export ports and border points in neighbouring FSU republics, while allowing Kazakhstan, Azerbaijan and Turkmenistan to obtain transit for some of their oil across Russian territory. Transneft is mainly responsible for co-ordinating transit operations, due to Russia's dominance in crude production and the location of most of the pipeline network on Russian territory. In 2000 about 86% of Russian oil exports to international markets transited neighbouring countries in the so-called "Near Abroad" (Russian terminology for the other FSU states). In 2000 Transneft handled almost 14 Mt of transit crude. It also transported over 6 Mt in imports for Russian consumers. Increasing Caspian production provides a significant opportunity for Russia, particularly the Transneft system, for expanded transit business. Because pipelines are high fixed-cost operations, the incremental volumes could provide a substantial economic benefit. Transneft has actively begun to solicit this business.

After several years of constrained quotas, the amount of Kazakh crude shipped to international markets *via* the Russian pipeline system more than doubled in 1999, to 8.1 Mt, and increased further in 2000 to 11.6 Mt. This reflects a series of inter-governmental agreements signed by Russia and Kazakhstan that have increased Kazakhstan's transit quota to 17.3 Mt, of which 12.3 Mt is to international destinations, and five Mt to CIS markets.

Azerbaijan has used the Transneft system to move its crude to international markets since 1997. The Azerbaijan International Operating Company (AIOC)[53] announced in 1995 that it would use two export routes for its "early oil" from the offshore Chirag field, shipping equal amounts through both Russia and Georgia. This resulted in the first long-term contract to be signed with Russia's Transneft, finalised by Azerbaijan/AIOC in early 1996. It envisages a total of 35 Mt shipped over seven years beginning in 1997, at a tariff of $15.67 per tonne over 1 411 km from the Russian-Azerbaijani border to Novorossiysk (the so-called "northern route"). After functioning reasonably well in 1997 and 1998, the pipeline became inoperable after May 1999 due to the fighting in Chechnya. Transneft began using rail to move the oil across Dagestan (between Makhachkala and Tikhoretsk) to bypass Chechnya and meet its

53. The AIOC is the consortium of international companies that has been developing Azerbaijan's first large offshore project, signed in 1994, for the Azeri, Chirag, and deep-water portions of the Gyuneshli field.

contractual obligations.[54] The export pipeline resumed operations in April 2000, via a new 280-km bypass pipeline around Chechnya completed in March 2000. SOCAR shipped 0.56 Mt in 2000 to Novorossiysk. In an attempt to remain commercially attractive for Azerbaijan's oil transit, Transneft has offered to pump only Azerbaijani oil through to Novorossiysk instead of blending it with Russian oil.[55] In response, Azerbaijan agreed to ship 2.2 Mt through the northern route in 2001.

The *Main Provisions* emphasise the importance of ensuring reliable transit of energy resources both for Russia itself and the countries on which it depends for transit services:

"For Russia, with its unique geographic and geopolitical situation, the transit problems have special importance both as for the country, whose main energy export flows depend on the transit policy of neighboring states, and as for the country, whose territory may become an important transit corridor for energy resources of the Central Asian and Caspian states. Thus, Russia has all the necessary objective pre-conditions for the transit to ensure both the reliable energy supply and export and revenues from transit functions".

Adoption of the Energy Charter Transit Protocol and ratification of the Energy Charter Treaty give Russia the possibility of establishing, together with neighbouring transit states, an international legal regime protecting the transit of crude oil. This would reduce the uncertainty associated with access to transit facilities and with the tariffs for using them. It should also increase their use and raise the potential for cross-border energy swaps. The Treaty and the Protocol reduce the probability of constructing redundant pipelines outside Russia, thus avoiding short-term pipeline-to-pipeline competition to Russia's detriment as the major incumbent player. A reduced likelihood of major disputes over transit due to the establishment of a minimum legal standard for crude-oil transit and the use of the transparent international dispute settlement mechanisms will also benefit Russia. It should be in Russia's long-term interest to make energy-structure decisions more on commercial grounds than with political considerations in mind.

►►► ***Ratification of the Energy Charter Treaty.*** *Ratification of the Energy Charter Treaty and adoption of its energy transit regime by Russia and neighbouring states would help to make transit negotiations between FSU states less political and even avoid the construction of expensive bypass pipelines.*

54. The oil reaching Novorossiysk in 1999-2000 was produced entirely by SOCAR, the Azeri State oil company, which is a partner in the consortium. AIOC discontinued use of the northern route for its own oil once the new "western route" through Georgia (Baku-Supsa) became available in April 1999. AIOC's transport shift reflects not only the improved reliability, but also lower transport costs and the capability of preserving the quality of the AIOC crude. The Baku-Supsa pipeline (530 mm in diameter) has been moving about 115 000 barrels per day (5.75 Mt per year), currently the rated capacity of the line, more or less matching the volume of oil produced by AIOC. There are plans for the line's capacity to be increased to 126 000 barrels per day (approximately 6.5 Mt per year) in 2001.
55. Russia's Export Blend has lower quality than Azeri Light, fetches a lower price in international markets and is a key factor favouring the alternate pipeline through Georgia over the Russian export pipeline.

PETROLEUM REFINING AND CONSUMPTION

Petroleum Refining Capacity

Russia's large refining sector comprises 28 refineries (Table 4.10) and about a dozen oil processing facilities, including lube plants, oilfield topping plants and specialised gas-condensate processing facilities. According to the Ministry of Energy, the refineries had a total primary distillation capacity of 296 Mt at the beginning of 1999. Collectively, the facilities operated at only 58% of capacity in 1999 compared with 87.5% in 1990, despite the elimination of almost 45 Mt of distillation capacity. Utilisation varies considerably from refinery to refinery. Given current excess capacity and the likelihood that refinery runs will fall even lower, a rationalisation of refining capacity is probably inevitable. Much of the redundant capacity is concentrated in the Volga and Urals region, e.g. in Ufa and Samara-Novokuybyshevsk.

In Russia, secondary processes represent only 45.8% of primary distillation capacity, and cracking capacity is barely 6%, (European and US refineries typically have as much secondary as primary processing capacity, allowing the entire barrel to be upgraded or converted into higher-quality products). The principal secondary refining processes used in Russia are hydro-treating and catalytic reforming, which together account for 64.0% of secondary capacity. (Hydro-treating accounts for over 42%.) These two processes are used to upgrade gasoline, kerosene and diesel fuel produced during primary distillation, but not to convert heavy fuels into light products.

Much of the processing equipment in Russian refineries is of indigenous design and manufacture, although equipment imported from Eastern Europe has played a prominent role. The technical quality of equipment at Russian refineries remains significantly below international levels, particularly for process-control equipment but also for major components such as compressors, pumps, filters and centrifuges. Many facilities are quite old, having been in operation for more than 30 years. The Energy Strategy envisages substantial development of the refining industry through construction and modernisation of capacity, particularly the deepening of the refining process. This could also improve environmental conditions by reducing emissions.

Refinery Output Mix

Refining depth, defined as the share of premium products (essentially light products and lubes) in the output mix, was 64.3% in 1998, compared with over 85% in most western countries. As a result of the limited amount of conversion processes, heavy petroleum products, particularly mazut (residual fuel oil) dominate the refinery output mix. Mazut comprised 31.0% of output in 1999, slightly below the 32.9% of 1990. Light products, such as gasoline, diesel fuel and kerosene currently account for less than 50%. This output mix has become increasingly out of balance with trends in product consumption, which increasingly favour light products. Excessive crude runs to meet light-product requirements have resulted in a large excess of mazut, which is disposed of as a low-value export. Long-term plans in the Energy Strategy call for refining depth to increase to 75% by 2010 and 85% by 2020, through a broad programme of refinery modernisation and the installation of additional secondary processing capacity, particularly new cracking facilities.

Table 4.10 Regional Distribution of Refinery Throughput in the RF, 1990-2000 (Million Tonnes)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Russian Federation	**297.2**	**287.0**	**250.6**	**229.8**	**188.1**	**183.2**	**176.8**	**175.2**	**164.5**	**170.1**	**174.1**
North (Ukhta refinery)	**5.5**	**5.3**	**3.9**	**3.6**	**3.0**	**2.7**	**3.0**	**2.9**	**2.1**	**2.1**	**3.6**
Northwest (Kirishi refinery)	**19.1**	**19.0**	**16.8**	**15.0**	**11.6**	**12.1**	**15.3**	**14.8**	**15.9**	**18.8**	**16.0**
Center	**44.7**	**44.5**	**39.3**	**34.7**	**27.4**	**27.0**	**19.6**	**21.4**	**24.5**	**30.5**	**31.7**
Moscow	11.6	11.9	10.8	9.0	8.6	10.0	8.9	9.6	8.7	8.9	9.3
Novo-Yaroslavl'	16.0	15.3	14.1	12.1	10.1	9.4	6.6	7.0	7.5	10.1	10.6
Yaroslavl' im. Mendeleyev	n.a.	0.4	0.5	0.4	0.2	0.2	0.1	0.2	0.2	0.2	0.2
Ryazan'	17.1	16.9	13.9	13.2	8.6	7.4	4.1	4.5	8.1	11.3	11.6
Volga-Vyatka (Norsi refinery)	**20.4**	**20.1**	**18.5**	**19.4**	**15.9**	**12.5**	**10.7**	**12.3**	**9.3**	**4.2**	**3.7**
Volga	**55.3**	**48.2**	**43.6**	**37.3**	**30.8**	**28.8**	**32.9**	**38.2**	**36.4**	**36.5**	**35.6**
Samara-Novokuybyshevsk	21.1	18.6	15.7	15.1	13.1	11.3	12.8	15.4	14.6	14.5	12.5
Samara (Kuybyshev)	6.7	6.4	5.4	5.1	5.1	4.9	4.9	5.6	5.2	5.3	4.9
Novokuybyshevsk	14.4	12.2	10.3	10.0	8.1	6.4	7.9	9.8	9.4	9.3	7.7
Syzran'	9.6	9.5	7.5	5.9	5.4	5.0	5.2	6.5	5.5	5.2	5.4
Kreking (Saratov)	8.9	8.8	7.2	5.6	2.4	1.6	2.4	3.5	3.2	3.3	3.7
Volgograd	8.2	7.8	7.9	6.8	6.7	7.8	7.8	7.7	6.8	8.0	8.4
Nizhnekamsk	7.5	3.5	5.3	3.9	3.2	3.1	4.7	5.1	6.2	5.5	5.6
North Caucasus	**20.6**	**18.8**	**15.6**	**12.1**	**5.9**	**4.8**	**4.7**	**3.8**	**2.5**	**4.3**	**4.8**
Groznyy	16.3	14.9	12.0	6.4	2.1	0.1	0.1	0.5	0.2	0.1	–
Krasnodarnefteorgsintez	2.4	1.9	1.3	1.4	0.5	0.4	0.3	0.2	0.1	0.1	0.1
Krasnodarekoneft'	n.a.	n.a.	n.a.	1.5	1.5	1.5	1.6	1.0	0.6	0.8	1.2
Tuapse	1.9	2.0	2.3	2.8	1.8	2.8	2.7	2.2	1.6	3.3	3.5
Urals	**65.7**	**59.6**	**57.7**	**46.9**	**41.9**	**45.5**	**44.5**	**40.9**	**37.4**	**36.1**	**40.2**
Ufa (total)	35.8	30.6	30.4	22.0	20.5	22.8	22.0	18.3	17.6	16.2	19.4
Ufa (Stariy)	n.a.	10.5	8.9	6.4	5.3	6.8	6.4	5.0	5.4	6.1	7.0
Novo-Ufa	n.a.	14.0	12.5	n.a.	7.6	7.3	6.8	6.0	5.6	4.5	5.9
Ufaneftekhim	n.a.	11.1	9.0	n.a.	7.6	8.7	8.8	7.4	6.6	5.6	6.5
Salavat	9.9	9.6	9.0	8.2	6.6	7.1	6.7	6.6	5.6	5.3	5.3
Perm'	13.3	12.8	12.4	12.0	10.4	11.2	11.4	11.2	9.7	10.5	11.1
Orsk	6.7	6.6	5.9	4.7	4.3	4.4	4.4	4.7	4.4	4.1	4.3
West Siberia (Omsk refinery)	**25.1**	**24.4**	**22.4**	**19.2**	**15.7**	**16.4**	**15.6**	**16.1**	**13.1**	**12.5**	**12.6**
East Siberia	**29.4**	**28.9**	**26.7**	**23.3**	**22.2**	**22.1**	**19.2**	**16.1**	**12.2**	**14.2**	**12.9**
Angarsk	22.6	22.1	20.3	17.6	17.0	16.6	13.4	10.3	7.2	8.5	7.7
Achinsk	6.8	6.8	6.4	5.7	5.2	5.5	5.8	5.8	5.1	5.6	5.1
Far East	**9.8**	**10.1**	**9.1**	**7.8**	**5.0**	**3.4**	**3.4**	**4.1**	**3.6**	**5.1**	**6.2**
Khabarovsk	4.2	4.5	4.1	3.3	1.9	1.7	1.7	1.8	1.7	2.0	2.6
Komsomol'sk	5.6	5.6	5.0	4.5	3.1	1.7	1.7	2.3	1.9	3.1	3.6

Source: IEA Statistics, PlanEcon.
–: refinery not in operation. n.a.: data not available.

Refinery Throughput

The last decade saw a sharp plunge in refinery operations during the economic transition. Refinery runs had been declining from a peak of 325.3 Mt in 1980, but began to contract sharply only in 1992 with the launch of economic reforms. The decline lessened somewhat in 1995-1997, due partly to a stabilisation of internal refined-product consumption but mostly to a deliberate policy of encouraging refined-product exports. In response to the economic crisis, throughput in 1998 dropped sharply again, to 45% of 1990 levels. In 1999 the government forced higher deliveries to the refineries under a mechanism that required specified domestic deliveries before allowing producing companies access to Transneft's export routes. As a result, refinery throughput in 1999 increased by 3.4%, to 170.1 Mt, and by another 2.4% in 2000 to 174.1 Mt.

Aggregate product demand will grow fairly slowly to 2020, while increased refining depth should limit the need for higher throughput. Moreover, refined-product exports, now running at about 50 Mt annually, will probably contract substantially. This combination should result in throughput levels somewhat lower than now even by 2020. Nevertheless, the Energy Strategy envisages growth in refinery throughput to 220-225 Mt by 2015-2020, as refining depth increases from its current levels of approximately 67% to 85% in 2020.

Refined-Product Consumption

Aggregate Consumption Trends for Refined Products

The Russian Federation is a large consumer of refined products (Table 4.11). Total final consumption contracted by 51% from 155.1 Mt in 1990 to only 75.9 Mt in 1998, following large declines in overall economic activity. Buoyed by a stabilising economy and administrative limits on product exports, TFC rose 11.6% to 84.7 Mt in 1999. Russian statistics show consumption declined again in 2000, falling by 6.4%. With the economic transition, oil demand is undergoing structural changes, by both sector and product. Traditional consumers like industry and electric power show declining importance in overall oil consumption, while the hitherto relatively limited role of trucking and private automobiles gains ground. These demand shifts clearly favour lighter products at the expense of mazut. Commercial and private transportation are key to increased demand for light products.

Sectoral Structure of Oil Consumption

Over the 1990s the transportation sector continued to consume about 50% to 55% of petroleum products. Industry's share dropped to about 12% in 1995 and 1996, but then rebounded to 16% in 1999. Agriculture's share contracted to slightly less than 7% in 1999 from about 10% in the early 1990s, while the residential sector's share remained constant over the 1990s at about 6%. The major change in oil-product use was by electric power plants and boilers, where the share of petroleum products out of total input fuels (including nuclear and hydro) dropped from 10% in the early 1990s to 5% in 1999.

Heavy Fuel Oil Consumption. Production of HFO declined 38% to 56 Mt between 1992 and 1999, while exports increased 17% to 23 Mt. The heat and power sector maintained its place as the number one user of HFO, although its consumption dropped to 72% of domestic supply in 1999 from 80% in 1992, reflecting the continued shift to gas. Industry consumed about 13% in 1999, after dipping to as low as 5% in 1994. The remainder was consumed in the residential sector (5%) and by ships. HFO use is likely to continue to contract over the next several years, due largely to continuing gasification of power stations and factories. As refined-product prices continue to rise toward world levels, the incentive to use crude oil to produce higher-value refined products will rise.

Gasoline Consumption. Private vehicle use drives gasoline consumption in most industrialised countries, but Russia has relatively few cars; trucks and buses still account for most gasoline consumption. About 75% of the truck fleet and 90% of the buses

Table 4.11 Oil Balance of the RF, 1990-1999 (in Million Tonnes of Oil Equivalent)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Crude oil production	**516.0**	**462.1**	**398.8**	**353.3**	**317.3**	**306.6**	**301.0**	**305.4**	**302.9**	**304.8**
Imports	18.6	12.6	10.7	10.4	4.9	8.5	6.8	4.0	5.6	4.7
Exports	222.9	175.3	128.7	128.2	127.4	122.9	127.1	127.5	137.9	135.2
Stock changes	0.0	0.0	-4.0	0.9	-2.2	-2.9	1.3	-0.1	-0.3	0.9
TPES	**311.7**	**299.4**	**276.8**	**236.3**	**192.7**	**189.3**	**182.0**	**181.8**	**170.3**	**175.1**
Refinery throughput	297.2	287.0	250.6	229.8	188.1	183.2	176.8	175.2	164.5	170.1
Other*	14.5	12.3	26.3	6.5	4.6	6.1	5.3	6.7	5.8	5.1
Petroleum products										
Imports	7.5	5.8	1.7	2.8	1.3	3.0	2.7	5.8	3.9	0.8
Exports	65.1	53.9	43.1	43.1	44.2	46.6	54.5	57.8	51.2	48.6
Stock changes	7.8	0.0	0.0	4.5	1.0	1.2	2.0	0.3	1.1	-0.2
TPES	**49.9**	**48.2**	**41.4**	**35.9**	**41.9**	**42.3**	**49.8**	**51.8**	**46.2**	**48.0**
Heat & power	60.9	61.3	58.0	55.8	46.1	37.7	35.8	29.9	33.0	26.4
Petroleum refineries	**271.9**	**281.8**	**250.5**	**222.2**	**185.8**	**178.1**	**172.5**	**171.7**	**162.5**	**166.4**
Own use / losses*	6.1	11.6	11.1	11.2	5.5	8.6	2.8	6.5	7.4	7.3
TFC	**155.1**	**160.8**	**140.0**	**119.3**	**92.2**	**89.4**	**84.1**	**83.5**	**75.9**	**84.7**
Industry	27.0	30.5	24.6	22.3	12.7	10.3	9.7	12.3	11.4	13.6
Transport	83.6	80.7	75.7	60.4	50.9	46.9	44.0	42.5	45.6	46.5
Agriculture	14.7	14.2	11.6	9.4	9.6	10.4	7.0	6.9	5.8	5.9
Services	0.4	0.4	0.3	0.3	0.4	0.4	0.3	0.2	0.2	1.0
Residential	8.9	8.8	8.6	8.3	6.0	5.3	4.5	5.3	3.5	5.2
Non-specified (other)	17.1	13.7	7.7	9.3	5.6	8.4	11.9	11.2	3.4	5.7
Non-energy use	3.4	12.5	11.5	9.4	7.2	7.7	6.6	5.1	6.0	6.9

** includes statistical difference.*
Note: 1990-1991 IEA estimates; 1992-1999 IEA statistics.

Table 4.12 Production and Exports of Major Refined Products in Russia, in Million Tonnes, 1992-1999

	1992	1993	1994	1995	1996	1997	1998	1999
Production								
Motor gasoline	35.3	30.1	26.8	28.1	26.8	27.2	25.9	26.3
Gas / Diesel oil	65.1	56.7	46.7	47.3	46.7	47.2	45.1	46.8
Heavy fuel oil	89.3	82.1	69.5	64.5	63.5	62.2	57.8	55.5
Exports								
Motor gasoline	4.1	2.8	1.8	2.0	3.7	5.0	2.8	1.9
Gas / Diesel oil	13.1	15.8	15.8	19.5	24.0	23.8	24.4	22.5
Heavy fuel oil	19.4	19.7	17.3	22.6	25.1	27.8	21.8	22.6

Source: IEA statistics.

run on gasoline. In 1999 cars accounted for 36% of gasoline consumption and trucks/buses about 64%, compared with only 22% and 69% in 1990.[56] Gasoline consumption plunged in the early 1990s and has continued to decline, albeit more slowly. By 1999 it had reached 23 Mt, 20% less than in 1992. The drop was almost entirely in trucks and buses, as consumption by cars rose steadily. The number of private cars was projected at 19 million in 2000 (128 per thousand population), compared with only 8.7 million (55 cars per thousand) in 1990.

56. Based on a generally assumed distribution in consumption between high-octane gasoline (A-91 or higher), used mainly by cars, and low-octane gasoline (A-80 or A-76), used almost entirely by trucks and buses.

Gasoline consumption by private automobiles will continue to rise substantially as the car fleet expands. Kilometres driven per car will also likely increase, although this will be largely offset by better average fuel economy as the fleet modernises. Commercial vehicle use (light trucks and vans fuelled by gasoline) should also rise with the continued expansion of private trade, retailing and small-scale manufacturing. A key issue concerns the extent that gasoline-powered trucks and buses give way to diesel vehicles. Declining gasoline consumption by trucks and buses will not likely be offset completely by increasing private automobile and light commercial vehicle consumption over the next decade.

Diesel Fuel Consumption. Diesel production dropped 28% between 1992 and 1999, to 47 Mt. Exports increased 71% over this period, reaching 23 Mt in 1999. Diesel fuel is consumed mainly in transport (especially trucking), agriculture and industry. The transport sector consumed 48% of domestic diesel-fuel supply in 1999, a slight drop from 54% in 1992. Agriculture, the next largest consumer, represented 23% of consumption in 1999. Other users include industry (13%), the municipal-residential sector (7%), and the transformation sector (6%).

The level of economic activity, especially in industry, will pull up diesel consumption in goods transport, with likely continued shifts over time from rail to road and from gasoline to diesel in trucks and buses. Overall, diesel-fuel demand will likely drive the recovery in overall product consumption, growing more rapidly than that of the other major products. Diesel use in agriculture is less likely to be affected by economic restructuring than that in other major sectors of the economy and, as in industry, will probably remain flat.

Kerosene Consumption. Aviation is the major kerosene consumer. Historically, military rather than civilian consumption appears to have dominated, but civilian use now probably is larger. While difficult to ascertain, military consumption apparently has undergone a dramatic downsizing. In civil aviation, changes in relative prices and technology are radically altering demand for air passenger services. In the past, highly subsidised airfares led to excess demand for air travel, and relatively inefficient jet engines consumed large quantities of fuel in the process. As airfares now have to reflect costs of operation, airlines have had incentives to restructure their flight schedules and purchase more fuel-efficient engines. By 1999, total final consumption of kerosene in international civil aviation had declined 40% to 8.3 Mt, from 13.9 Mt in 1992.

Development of Regional Markets

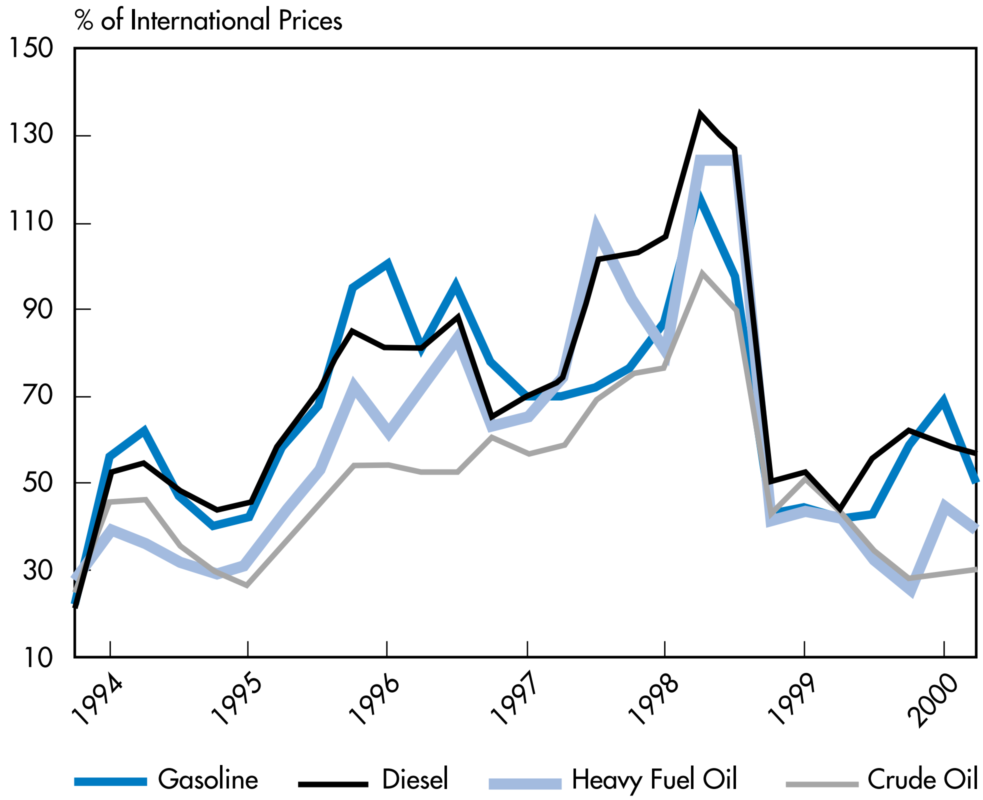
Individual refineries must deal with broad changes in fuel demand as they occur within their regional markets, which are contracting geographically due to higher relative transportation costs as railroad tariffs rise to full cost-recovery levels. An important issue will be the restructuring of market areas among the refineries (and a resulting shakeout of capacity) stemming from substantial regional mismatches between refinery output and regional consumption.

Trade in Refined Products

Russia has traditionally exported sizeable amounts of refined products outside the former Soviet territory and to the FSU. Trade volumes and the product structure have shifted, although mazut and diesel fuel remain dominant, each accounting for around

50% of total exports to non-FSU markets. Exports of mazut have represented one of the few sources of flexibility to alleviate the constraint of a fixed refinery slate. Refined-product exports to destinations outside the USSR peaked at 42.2 Mt in 1988. After contracting sharply to only 25.3 Mt in 1992, they rebounded to a record 58.4 Mt in 1997. Due to low international prices and high domestic transport costs, product exports contracted again in 1998 until the devaluation of the rouble in August. In 1999 and 2000, reduced transportation costs and crude acquisition costs from the devaluation, caused product exports to expand again, reaching 58.4 Mt in 2000.

Figure 7 Russian Crude Oil and Refined Product Prices, 1992-2000



Russian oil markets have made considerable progress toward liberalisation, although major distortions persist in crude and refined-product prices (Figure 7) as well as in rail freight rates for moving export products to ports. Following the rouble devaluation in 1998, which brought domestic crude prices well below world levels again, refineries had an artificial incentive to export as much product as possible. In 1999, the government imposed a series of administrative restrictions on product exports and re-established export duties to control the outflow. It re-imposed quantitative restrictions in September 2000 to ensure supplies (mainly diesel) to harvesters and winter stock build-ups (fuel oil restrictions were in place from September 2000 to April 2001).

►►► ***Elimination of Price Distortions in Domestic Oil Product Markets.*** *Because large investments will be required to modernise and upgrade Russia's refining sector, it is important that oil companies receive correct market signals about changes in demand as they make their investment decisions. Setting railroad and product-pipeline tariffs at cost-recovery levels, as well as the elimination of domestic delivery quotas and distortions in pricing, would certainly provide correct market signals. Companies should be encouraged to rationalise refining capacity based strictly on cost (and not tax) considerations and to modernise plants to comply with increasingly strict environmental standards.*

Economics of Exporting Refined Products

Refined-product exports generate lower average prices than does crude, because at least 50% is comprised of relatively low-value mazut. Their rail transport to ports is costlier than moving crude by pipeline, and refining represents an additional expense.

By temporarily scrapping export taxes on products to compensate for oil-price and rail-tariff hikes in 1995-1996, the government provided direct financial incentives to export products instead of crude. This not only reduced oil-export revenues and profits (netbacks) for the economy as a whole, but reduced export tax revenues as well, because products are taxed less than crude exports. (Currently, crude exports are taxed at 34 euros per tonne, with light and medium distillates at 32 euros per tonne and fuel-oil exports at 27 euros per tonne.) This policy cost an estimated $956 million in hard-currency revenues in 1999.[57]

Political pressures to maintain refinery operations and the need to pay for refinery modernisation represent strong incentives to continue favouring product exports. Nevertheless, such exports can be expected, on balance, to contract. With the ongoing adjustment of prices and costs, refinery utilisation in excess of local demand should once again become a net-loss operation, with incremental refining and transportation costs exceeding incremental product netback. In a more commercial economic environment, this would further encourage refinery rationalisation. As government policy continues to focus on maintaining a sizeable flow of refined-product exports, one priority espoused by the Energy Strategy is to bring product standards up to world levels in order to maintain sales into the European market.

Distribution of Refined Products

With the economy now stabilising and returning to solid growth, the fortunes of Russia's oil companies are likely to link increasingly with domestic sales and less with exports. Dramatic changes have occurred in recent years in the supply system for refined products. Following the liberalisation of oil prices, downstream margins were excellent, especially at the retail end. In response, many Russian oil companies began to modernise and expand their distribution capability beyond their traditional territories, a strategy facilitated because retail development is not as capital-intensive as upstream development. Although the Ministry of Anti-Monopoly has concluded that no single company possesses a market share greater than 35% nationally, it notes that competition is often lacking regionally, with a single company often controlling up to 80-90% of a local market. The main reason for this is that the vertically integrated companies were formed on the basis of existing regional distributors. Other reasons include high

57. According to Goskomstat figures, the average export price in 1999 for a tonne of Russian crude was $111 versus $91 per tonne for refined products.

entry barriers, such as large initial capital requirements, poorly developed inter-regional transportation infrastructures (especially product pipelines) and difficulties in obtaining permits and acquiring land for facilities.

Vertically Integrated Oil Companies and Product Distribution

Competitive pressure from small and efficient market participants is intensifying, with some already emerging as the leading forces in many regional markets. By 1999 the Russian VICs owned only about 30% of the 20,000 to 25,000 filling stations in the country. Some government officials considered the reduced presence of the VICs at the retail level as a major cause of the "gasoline crisis" that emerged in the spring and summer of 1999. The then Minister of Fuels, Viktor Kaluzhniy, called for "harsh measures", including a cut-off of fuel deliveries to independents, to force a reorganisation of the retail gasoline market and put all stations under the control of major companies.

►►► ***Elimination of Entry Barriers to Downstream Oil Markets.*** *To increase competition in regional product markets that remain monopolised, the Anti-Monopoly Ministry should continue to favour policies that lower barriers to entry by other downstream operators.*

5. NATURAL GAS

EXECUTIVE SUMMARY

The Upstream Sector

An estimated one-third of the world's natural gas reserves remains in Russia's super-giant fields and smaller fields adjacent to the super-giants, which ensure the availability of future supply. Russia also has a range of opportunities to import gas on commercially attractive terms from Central Asian and Caspian countries through established pipeline networks. Russia is not "short of gas". Established resources will be adequate for the next several decades. Supplies will be adequate until well into this decade, but investments in future supplies – domestic or imported – will need to be made several years ahead of anticipated requirements.

Security of supply will not be a major problem unless there is a failure to reform the price and tax regime of the late 1990s. Russia can continue servicing its current and growing export market. This is true despite concerns expressed by Gazprom and the Russian government about the availability and viability of new gas supply, about Russia's high dependence on natural gas (50%) and especially that of the electricity sector in European Russia (over 70%).

Transportation and Third Party Access

The government's Economic Strategy and the Commission on Access to Oil and Gas Pipelines foresees the gradual liberalisation of the gas industry. Non-discriminatory tariffs already exist, but there is a need to create access rules for the use of the transmission system which allow for independent determination of available capacity. Strengthening the regulatory system will eventually achieve the government's goal of creating competition in both the production and marketing of gas. The immediate emphasis is on bringing new producers and marketers – independent gas companies and the vertically integrated oil companies – further into the gas market than hitherto, by allowing them access to the Gazprom network. The speed of achieving competition and its extent will depend on the success of price reform and the exercise of political will necessary to create appropriate standards of governance and transparency among powerful interests in the gas sector.

The Russian Market: Demand, Prices, Payments and Taxes

From 1995 to 2000, domestic gas prices did not move towards international levels, defined as European import prices. At their highest point in 1995, industrial gas prices in Russia stood at just under 60% of average European import prices, but well above costs of delivery. After 1997, industrial prices fell to around 20% of European import prices, only just covering costs of delivery. Residential gas prices were substantially lower. The *Main Provisions of the Russian Energy Strategy to 2020* called for raising prices by as much as 350% by 2005 and for reaching parity with European import prices by 2007. Assuming these increases were combined with prompt cash payment, this would provide more than ample incentive for substantial new investments in both demand reduction and additional supply for the Russian market. Such price increases could lead to bankruptcies, however, particularly in energy-intensive industries, with consequent unemployment and social dislocation. Reform of the tax system will also need careful implementation. Gazprom is one of the most highly taxed companies in Russia, accounting for about 25% of federal tax receipts.

Exports, Joint Ventures, Export Pipelines and Gas Transit

Gas exports increased slowly but steadily during the late 1990s. In terms of exports to CIS countries, the marketing company Itera became almost as large a player as Gazprom in terms of volume. More important, it arranged transportation of and payment for Central Asian gas deliveries to other CIS countries. For exports to European markets, the principal problem of the past five years has been transit of gas through Ukraine. Frequent diversions of Russian gas in transit to Europe have led Gazprom to concentrate on building pipeline systems around Ukraine. The Yamal and Blue Stream pipelines are illustrative of that policy. When they are completed, gas exports to Europe will surge to around 200 Bcm/year by 2008 (up from 130 Bcm in 2000), so long as Ukraine succeeds in maintaining full transit capacity. Thereafter, Gazprom's current ambitions in the European gas market appear to be limited, with exports anticipated to rise to a maximum of 220 Bcm in 2020.

After 2010, there may be a change of export priorities towards Asian markets. A number of projects are aiming to sell gas to China, Japan and Korea from fields around Sakhalin Island, Irkutsk and Sakha Republic. Multinational companies are major shareholders in the Sakhalin and Irkutsk projects. At present, Gazprom has no direct involvement in these projects, but has expressed interest in participating and in exporting its own gas to Asian countries.

The Future of Gazprom

The Russian gas industry is dominated by Gazprom, the world's largest gas company. In 2000, it provided 20% of federal budget revenues and about 20% of convertible currency revenues. A hasty, poorly-thought-through restructuring of Gazprom would be extremely risky and potentially destabilising for the entire Russian economy. The government's stated strategy is "management unbundling" – financial and organisational separation – of Gazprom's pipeline network from its production units over the next several years, in an attempt to encourage further competition and non-discriminatory access to the transmission system. What is lacking is a detailed timetable for this restructuring strategy and how it will be coordinated with price reform. A new Gazprom CEO with close links to the Russian president was appointed in June 2001, and the government gained majority control of the Gazprom board. An important determinant of Gazprom's policy will be the speed of change in the company's top management.

THE UPSTREAM SECTOR

Reserves and Production

The gas industry has been the mainstay of the Russian energy sector during the transition to a market economy, and specifically since the break-up of the USSR in 1991. Gas production fell by less than 10% over the past decade, as against much sharper declines in other fuel sectors. The maintenance of high production and low price relative to other fuels has brought gas's share in the Russian energy balance to nearly 50%. Gas demand in Russia dropped to its lowest point in 1998, 18% below 1991, but has since increased. During 1995-2000, Russian gas exports to Europe increased by more than 10%. Over the same period, exports to former Soviet Republics increased by 20%, due in large part to re-exports of Central Asian gas by the marketing company Itera.

The Russian Gas industry is dominated by the OAO "Gazprom", the world's largest gas company. Gazprom is a privatised company, in which the Russian government maintains a major share.[58]

In 2000 it:

- produced 90% of total Russian gas output;
- controlled virtually all the gas transported through high-pressure, large diameter pipelines;
- controlled all gas exports to Europe;
- provided 20% of Federal budget revenues and around 20% of convertible currency revenues.

Reserves

In January 2001, official Russian gas reserves were estimated at 46.9 trillion cubic metres (Tcm), just under one-third of world proven gas reserves.[59] Of this total, Gazprom's share is 64% or 29.9 Tcm. Since 1997, Gazprom's reserve base has been re-evaluated according to western "proven and probable" classifications by an internationally recognised company specialising in reserve audits. Appraisal of 84% of Gazprom's gas fields has resulted in 19.4 Tcm of proven and probable reserves.[60] Gas reserves declined somewhat during the 1990s, as reduced investment in exploration prevented reserve additions from keeping pace with production. Yet even with conservative estimates of proven and probable reserves, Gazprom production could be maintained for more than 40 years at the 2000 level. Adopting Russian reserve figures would increase the production life of country's existing reserves to 80 years.

Production

Russian gas production fell from a peak of 643 billion cubic metres (Bcm) in 1991 to a low of 571 Bcm in 1997, before recovering to around 591 Bcm in 1998 (Table 5.1). Russian production has subsequently dropped slightly, but Gazprom's has fallen steeply – by more than 20 Bcm in 2000 – giving rise to speculation that a substantial and irreversible production decline was imminent. Gazprom projections suggest that the company's production will fall further and, in the best case, stabilise at 1999 levels until 2020. If this is correct, any increases in production would come from non-Gazprom production in existing producing regions, new production in Eastern Siberia and the Far East (where little gas is currently produced), from independent producers and joint ventures. Given the forecast decline of fields now in production, a great deal of new capacity has to come on stream over the next two decades to maintain current production levels. With lead times of five to seven years to bring large fields in the

58. At 28 December 2000 the company's shareholders were the Russian Federation government (38.37%), Russian legal entities (33.64%), Russian individual shareholders (17.68%) and foreign investors (10.31%) of which 3.5% is held by *Ruhrgas*). Gazprom Annual Report 2000, p.17.
59. Although the Russian figure is not strictly comparable to the western "proven plus probable" classification.
60. Gazprom Annual Report 2000, p.25.

Table 5.1 Russian Gas Production by Company 1995-2000 (Bcm)

	1995	1996	1997	1998	1999	2000*
Russian Federation of which:	**594.8**	**601.0**	**570.5**	**590.7**	**590.8**	**584.2**
Gazprom	**559.5**	**564.7**	**533.8**	**553.7**	**551.0**	**523.2**
– West Siberia (Nadym Pur Taz) of which:	519.2	526.9	496.4	515.3	507.1	487.4
• Urengoygazprom	242.9	242.2	227.2	223.8	209.1	193.3
• Yamburggazdobycha	177.8	176.5	169.3	179.6	175.9	168.0
• Nadymgazprom	64.4	65.3	54.0	65.1	72.4	72.4
• Surgutgazprom	34.1	40.3	45.8	46.7	49.7	49.0
– European Russia						
• Orenburggazprom	30.8	28.7	27.0	25.5	24.8	24.1
Other companies of which:						
Itera				2.0	6.6	17.7
East Siberian companies	6.1	6.1	5.7	5.8	6.0	6.0
Oil companies	29.0	29.1	29.4	28.9	29.6	32.3

** figures from Infotek may not be comparable with previous years.*
Sources: for 1995-1999: IEA; "Fuel & Energy of Russia", A.M. Mastepanov, MinEnergo, 2000; and for 2000: Infotek.

Nadym-Pur-Taz region into production, development plans need to be set well ahead of time.

The production projections in Table 5.2 from the Russian Energy Strategy show that overall production is projected to increase by a maximum of 20% over the next two decades and that Eastern Siberia and the Far East will account for around one-third of that increase. In this scenario, production from the Nadym-Pur-Taz fields in Western Siberia, which accounted for more than 85% of total Russian output in 2000, would barely increase. New fields would just compensate for production declines at the three currently producing super-giant fields. These three, which accounted for 80% of 1999 production, are expected to fall precipitously over the next two decades. Gas production at existing fields in 2020 is expected to be about 142 Bcm, 20-22% of projected production in that year. Nadym-Pur-Taz production would be supplemented first by gas from the Barents Sea (from the offshore Shtokmanovskoye field) and then, after 2015, by production from the Yamal Peninsula fields.

Table 5.2 Russian Gas Production Projections 2000-2020 (Bcm and Regional Breakdown* in Percentage of Total)

	2000	2005	2010	2015	2020
Russia (Bcm)	**584**	**580-600**	**615-655**	**640-690**	**660-700**
European regions	**7%**	**6%**	**13%-14%**	**13%-14%**	**17%-18%**
– Barents Sea**	–	–	65%	63%	70%
Western Siberia	**91%**	**92%-93%**	**81%-83%**	**79%-81%**	**75%-76%**
– Nadym-Pur-Taz	87%	95%-96%	95%	94%	80%-84%
– Yamal	–	–	–	–	11%-16%
Eastern Siberia	**1%**	**1%**	**2%-3%**	**2%-3%**	**4%**
– Irkutsk	–	–	60%-73%	80%-81%	80%-81%
Far East	**1%**	**1%**	**1%-3%**	**2%-3%**	**2%-3%**
– Sakha Republic	47%	50%	50%-60%	25%-45%	31%-40%
– Sakhalin	53%	50%	40%-50%	55%-75%	60%-69%

** Regional breakdown of gas production is from the March 2000 draft of the Strategy. **Shtokmanovskoye field.*
Source: "Main Provisions of the Energy Strategy of the Russian Federation to 2020", November 2000.

The *Main Provisions* raise two separate issues for the Energy Strategy production scenario: the projection of *total* production and that of *Siberian* production, in particular the decline at the super-giant fields. The insistence that production is a function of general economic activity and of the level of domestic and export prices and taxes, rather than resources, is entirely realistic and a welcome change from the past. On the other hand, the expectation of roughly constant overall production up to 2005, followed by a slow increase over the next 15 years, may still prove too optimistic. Nevertheless, it is welcome that the forecasts of the past 30 years, which projected production well above 700 Bcm in 2010 and in the range of 800-1000 Bcm by 2020, while possible purely in terms of resource availability, have been recognised as economically unrealistic. Future supply development must be a function of the ability and willingness of customers – domestic and foreign – to pay prices high enough to support the required investments.

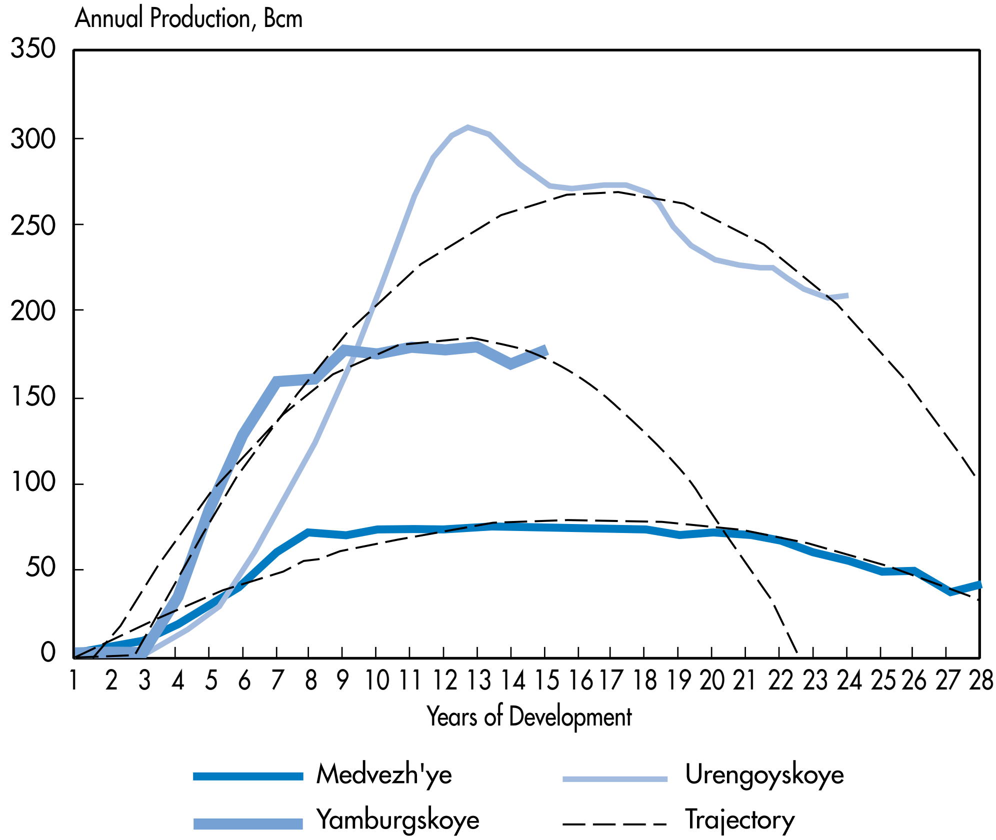
It is not quite clear why Gazprom and the Russian government expect such steep declines in the super-giant Siberian fields (See Map 4). The historical decline curve of the Medvezh'ye field does not lead to the conclusion that the other two fields will enter into rapid decline. Figure 8 shows that the Med'vezh'ye field (with 22% of Cenomanian[61] gas reserves remaining) had a plateau production of around twelve years and has been in gentle decline for eight years; twenty years after the start of plateau production, it is still producing at half of its plateau volume. By contrast, thirteen years after peak production, Urengoy has declined by about one third. Yamburg has been producing at plateau for only six to seven years. At Urengoy and Yamburg, 43% and 54% of cenomanian gas reserves – around five trillion cubic metres – remained in 2000 to be produced.

The crucial judgement about production declines at these fields is whether over-rapid output increases during the Soviet era damaged the ultimate recoverability of the fields. Evidence to this effect is far from conclusive. With appropriate investment in production infrastructure, the decline in output has been staved off at Medvezh'ye field, and there seems no reason why the same cannot be done at the Urengoy and Yamburg fields. The remaining five Tcm of Cenomanian reserves, plus three Tcm of reserves remaining in the deeper Valanginian and Neocomian horizons of the fields, suggest there will be no shortage of reserves even at very high production levels. The deeper horizons are more complex, requiring higher investments to recover the gas, but substantial production should be viable and available for as long as 20 years. For these reasons, a projection in the Strategy suggesting that production will fall from more than 400 Bcm/year at the end of the 1990s to around 120 Bcm by 2020 seems unduly pessimistic.[62] The key question is whether required investments will be made and, as noted above, this will depend on the expectation of adequate returns on investment.

If the Urengoy and Yamburg fields do indeed experience the decline projected in the Energy Strategy, nearly 300 Bcm of new production capacity would need to be developed in the next 20 years. One option would be to open up new West Siberian fields where production costs will be higher than for the existing super-giants. Zapolyarnoe, with

61. Cenomanian gas reserves are those obtained from relatively shallow horizons of the field.
62. The figure of 120 Bcm reflects the assertion in the Strategy that total production from existing fields would be around 142 Bcm in 2020. Some versions of the Strategy have projected production from the three super-giant fields as low as 83 Bcm in 2020.

Figure 8 Production Curves for Urengoy, Medvezh'ye and Yamburg Gas Fields



3.4 Tcm of reserves and a production plateau of 100-150 Bcm per year commenced production, in late 2001. Gazprom has a joint venture with Shell to develop liquids and gas production from the deeper horizons of the field.

Overall costs of gas delivered to customers depend crucially on transportation costs and hence the proximity of fields to existing transmission lines. New fields located near the existing production facilities of Nadym-Pur-Taz will require new pipelines of up to 300 km to connect them to the existing transmission system. These are far more attractive economically than the larger, but more remote, fields on the Yamal Peninsula, which will require much longer transmission lines traversing more difficult terrain. This is the main reason why Gazprom – and the Energy Strategy – suggest that the next large increments of Siberian production should come from the Kamennomysskoye fields, which lie partly in the Ob-Taz Gulf around 150 km from the Yamburg field. Reserves have been estimated at 3 to 4 Tcm; production is scheduled to start in 2007 and reach a plateau of 50-56 Bcm in 2010. A large proportion of the small- medium-sized fields in the Nadym-Pur-Taz region, with reserves of 1.9 Tcm, have been licensed to Itera (or other consortia in which that company holds a dominant position). Itera projects its production at 70-80 Bcm in 2010 (see box page 116).

Outside Siberia, the major production prospect noted in the Energy Strategy is the Shtokmanovskoye field in the Barents Sea. Shtokmanovskoye is an offshore field with three Tcm of reserves that will require a very long pipeline to Russian and European markets (see Map 5). Despite the high capital costs of developing the production and transportation infrastructure for Shtokmanovskoye, the Energy Strategy assumes the field will be in production by 2010. This appears ambitious given the financial and organisational problems ahead. Shtokmanovskoye is the only field in the Barents and Kara Seas where development is anticipated before 2020. The Strategy notes that the super-giant fields on the Yamal Peninsula, whose development has been under discussion since the 1980s, are 1.5 times more expensive to develop than Shtokmanovskoye. The Yamal fields are also said to present environmental problems because of the fragility of the arctic area in which it is located.

In European Russia, the only other large new fields that could be further developed are around Astrakhan, where the main obstacle is the cost of the plant required to process gas with very high sulphur content. Further development of the Astrakhan field – where the Italian company ENI has a joint venture with Gazprom – could provide gas for the Blue Stream pipeline to Turkey. It is slightly surprising that the Strategy makes only passing reference to possible development of up to 500 smaller fields elsewhere in European Russia. Although most of these fields contain less than 20 Bcm of reserves and many have low flow rates, they are attractively located near markets and could have low production and transmission costs. Domestic price reform is essential, however, for these fields to become attractive to investors. It is precisely this type of field that could lure independent producers.

Taxes and regulated prices preclude the import of gas from Central Asia and the Caspian region for sale within Russia. Because Central Asian gas transits through Russian pipelines to other CIS countries, imports from these countries should be attractive when compared with Russian greenfield supply through new pipeline networks.

►►► ***New supply should be sought from least-cost sources, including foreign ones,*** *given the shortage of capital investment and the uncertainty in the fiscal and regulatory frameworks. Serious thought should be given to the potential for additional future supply from the Nadym-Pur-Taz fields before investments are sunk into multi-billion dollar greenfield supply with uncertain financial returns. Artificial tax and price impediments should be removed for basic economic reasons as well as because they penalise the sale of Central Asian gas in Russia.*

There is no indication that energy-efficiency projects have been seriously evaluated as an alternative to additional supply. For much of the 1990s such projects would not have been financially worthwhile, given price and the (non-) payment habit. In 2000, the price/payment situation improved and the proposed price reform will bring energy-efficiency projects onto the agenda, not least in the context of the "joint implementation" flexible mechanism foreseen in the Kyoto Protocol. A good example of an attractive energy-efficiency project could be refurbishment and upgrading of old gas-fired generating and co-generation plants. However, even such potentially attractive projects will pose a financial challenge until prices are raised to cover costs and bills are paid as a matter of course.

►►► ***Energy efficiency projects should be considered and evaluated as an alternative to additional supply.*** *Serious thought should be given to demand-side management and improved efficiency of gas use as an alternative to additional supply.*

Other Producers

Independent producers are a new concept in Russia. For the first time in the history of the Soviet and Russian gas industries, the dominant entity is not the only significant producer to be considered in terms of future policy and output. A new gas company, Itera (see Box), emerged in the late 1990s to become extremely important not only for sales to CIS countries but also as a supplier to the Russian market.

ITERA

Itera was founded in 1992 as a company trading in consumer goods, oil and oil products in the former Soviet republics. It entered the gas market for the first time in 1994 when Turkmen companies with which it was trading were unable to pay for goods except with gas. The company found itself receiving gas for which it was forced to arrange transportation and sales to customers in Russia and other CIS countries. From these beginnings, Itera has grown steadily. In 2000, it sold nearly 80 Bcm of gas to customers in the CIS and the Baltic countries after 60.5 Bcm in 1999. This figure places it among the top six gas-marketing companies in the world. The sales come from three major sources:

- *Production*: the company produced nearly 18 Bcm in 2000, a figure planned to increase to 50 Bcm by 2005 and 80 Bcm by 2010. *Itera's* main gas production comes from the Gubkinskoye and East Tarkosale fields in Western Siberia.
- *Russian purchases*: the company buys 30 Bcm/year of gas for sale on commission from regional authorities in the gas producing Yamal-Nenets *Okrug* of Siberia, which receive gas from Gazprom for royalty and tax payments.[63]
- *Central Asian purchases*: 35 Bcm are purchased from Central Asian countries each year, principally from Turkmenistan (but also Uzbekistan and Kazakhstan).

Within Russia, Itera sold more than 36 Bcm of gas in 2000, all of it delivered to customers within a 1 400-km radius of the fields where it is produced. More than half of Itera's Russian sales are in Yekaterinburg (Sverdlovsk), where the company has a marketing affiliate. Outside Russia, the company's biggest market is in Ukraine, where in 2000 it delivered 32 Bcm, followed by Belarus, Kazakhstan, Armenia, and Georgia, as well as Moldova and the Baltic countries (see Table 5.15). Itera is involved in joint ventures for transportation and sales of gas in Armenia, Azerbaijan, Georgia, Latvia and Estonia. The company has proposed a pipeline link between Georgia and Turkey, suggesting that it has ambitions to sell gas outside the CIS, which would bring it into direct competition with Gazprom.

The unique feature of Itera's business is not simply the rapidity with which it has grown, but the way in which it has surmounted the hurdle of non-cash payment by using its skills as a trading company to deal with barter goods.

63. In early 2001, the Russian Audit Chamber ordered Gazprom to cease paying its taxes to the Yamal Nenets authorities in gas. This has cut an important source of Itera's supply.

The company receives and delivers all types of goods – food, industrial products and metals – in exchange for gas, in a manner that recalls the traditional Soviet way of doing business. The company also has major non-gas investments, including steel (in Moldova), plastics (in Russia) and gold (in Mongolia).

Itera's rapid emergence as a major force in the Russian and CIS gas industries and the growing scale of the company's operations have given rise to widespread speculation about the propriety of the company's relationship with Gazprom. Itera is sometimes referred to as a "Gazprom subsidiary". The main issues under investigation are:

- how Itera and consortia in which it has a dominant position acquired fields with total reserves of 1.9 Tcm;[64]
- the terms on which Itera – as the only large-scale user of Gazprom's transmission system – has had its gas transported; and
- any ownership relationship between Gazprom's board and Itera.

Itera has consistently maintained that, while the company has what it describes as a "partnership" with Gazprom:

- it operates independently from Gazprom;
- no gas has been purchased from Gazprom;
- regulated tariffs are paid for transportation;
- neither Gazprom nor its officers own any shares in Itera.

In 2001 investigations by the Russian government's Audit Commission and Gazprom auditors Price Waterhouse into the relationship between Gazprom and Itera failed to discover any improprieties which were sufficiently serious to warrant legal action.[65]

Russian oil companies (and their ministerial predecessor) have always produced substantial quantities of gas, both in association with crude oil production and as non-associated gas.[66] Table 5.1 shows that Russian oil companies have increased their gas production since 1998, but still accounted for only 6% of total gas production. Table 5.3 shows that production in association with oil peaked in 1990 at more than 38 Bcm, but fell to 25 Bcm by 1995, increasing only to 29 Bcm by 2000. During the Soviet era, the flaring of associated gas approached the volume collected and used. During the transition this situation has improved, but the options available to oil companies to dispose of their associated gas are still not attractive, primarily because of lack of access to gas processing plants (see below). Value is therefore being lost and emissions are higher than should be the case.

64. According to Itera (2000) the 1.9 Tcm of reserves include the following fields: Gubkinskoye, Vostochno-Tarkosalinskoye, Novo-Urengoiskoye, Beregovoye and Yuzhno-Russkoye.
65. "Gazprom-Itera Relations do not Violate Russian Law – Price Waterhouse Coopers", *Interfax Petroleum Report*, August 3-9, 2001, pp. 19-20
66. See the Energy and Environment Chapter for discussion on the flaring of associated gas by Russian oil companies.

The other potential category of producers includes foreign companies interested in upstream gas investments. In the past, both government and Gazprom rebuffed foreign companies on the grounds that there was no reason to allow foreign companies to produce what Russians could equally well produce. Over the past decade, that view has changed somewhat. Foreign firms have been invited to form joint ventures with Gazprom[67] or participate in joint operating companies to develop specific fields or groups of fields.

Gazprom's three major upstream joint natural gas ventures are:

- with Shell, to develop the deeper oil and gas horizons of the Zapolyarnoye field;
- with ENI, to develop deep horizons of the Astrakhan field, which has gas with a very high sulphur content;
- to develop the offshore Shtokmanovskoye field in the Barents Sea with a number of partners, including Conoco, Total/Fina/Elf, Norsk Hydro and Fortum Oil and Gas of Finland.

The three Gazprom joint ventures all require technology not currently available to Gazprom. All of the projects require very large capital investments, which the Russian partner would not be able to raise. In 2001, for a variety of reasons, none is moving very rapidly towards a conclusion, despite their having been under consideration for some years.

The most important projects involving joint operating companies are those in eastern Siberia and the Russian Far East, especially the Sakhalin projects (1-6) and Kovykta. "ArcticGas" is a smaller joint venture, with rights to the Samburg-Evo-Yakha license in the Urengoy area and estimated natural-gas reserves of 919 Bcm. Gazprom does not currently hold any equity in the Sakhalin projects or Rusia Petroleum (which has the license for the Kovykta field). Gazprom owns about 12% of ArticGas shares and it is actually an independent producer, carrying out its activities without the investment of Gazprom.

TRANSPORTATION AND THIRD-PARTY ACCESS

Transmission

One of the biggest problems for the entire Russian energy sector is the age and condition of its infrastructure. Of more than 150,000 km of high pressure, large diameter transmission lines, 70% was commissioned before 1985 and more than 19,000 km of pipeline are beyond their design life-span and need replacement. The investment requirements of the transmission system will, therefore increase sharply over the next two decades. In general, the high-pressure transmission system – for which Gazprom has responsibility – is in better condition than the low-pressure distribution systems maintained by regional and local companies with meagre investment resources.

The Main Provisions project that production from Western Siberia will peak at a maximum of 557 Bcm in the period up to 2020, and possibly less. The Yamal fields

67. Further discussion on *Gazprom* joint ventures and strategic alliances in the areas of transmission, storage and marketing are discussed in the section on Exports, Joint Ventures, Export Pipelines and Gas Transit, p. 133.

will produce a maximum of 60 Bcm at that date, but they could still be waiting to be developed. If that is the case, there will be no need to build additional transmission pipelines from Siberia to the west of the country during the next two decades. By the end of the period a maximum of two new pipelines connecting the Yamal fields with the existing network at Ukhta could have been completed.[68] Most investment in high-pressure transmission can go to connecting new fields to existing east-west pipelines and replacing and refurbishing those lines at the end of their operating lives. The Energy Strategy suggests that it will be necessary to lay 23,000 km (including replacement) of transmission pipelines up to 2020 and 25 GW of compressor-station capacity. New export projects (see below) will account for part of this.

Distribution

During the latter part of the 1990s, gas distribution companies were privatised and became independent. Severe financial problems – principally resulting from non-payment – drove many distribution companies into insolvency. This in turn led to a wave of mergers. By 2000, there were about 378 distribution companies compared with almost twice that number in the early 1990s. Indebtedness of regional distribution companies to Gazprom has led to its acquiring more than 50 of the largest distribution networks. In 1999, Gazprom owned 54,000 km of distribution pipelines and supplied over 17 Bcm of gas to two million households, 10,000 municipal and 1,150 industrial customers and 2,500 CHP systems. By 2000, Gazprom estimated that it owned 10% of the entire distribution network. This goes against what is proposed for Gazprom's activities in the government's Economic Strategy.[69]

►►► **Gazprom*'s vertical integration into the distribution sector should be halted.*** *Although it is the natural consequence of debts owed to it by distribution companies,* Gazprom*'s vertical integration into the distribution sector is highly undesirable.* Gazprom *should be prevented from taking over any more distribution companies. In time, it could be required to divest itself of those that it presently owns.*

The *Main Provisions* project that 75,000-80,000 km of distribution pipelines will be built by 2005, of which 75% will be in rural areas and in the Russian Far East, where there is very little gas supply. With the prices and payments record of the late 1990s, it would be difficult to make an economic case for such investments. Nevertheless, gasification is ongoing in regions such as Astrakhan *oblast* and the city of Arkhangelsk.

Storage

In 2000, Gazprom, the only owner of underground gas storage in Russia, operated 22 underground gas storage sites, 16 in depleted gas fields and six in salt caverns. At 1 January 2000 the nominal capacity of these facilities was 56.5 Bcm, with an average daily working-flow capacity of 387 000cm/day. Gazprom also had access to foreign storage sites: in Ukraine (17.5 Bcm), Latvia (1.9 Bcm) and Germany (1.5 Bcm).[70] The company plans to refurbish and expand existing sites and to build new ones in several countries in the CIS, Eastern Europe and elsewhere.

A very interesting feature of the Russian gas balance (Table 5.3) is the increase in storage during the 1990s. Except for 1997, when the figure was negative, annual net

68. It seems that the majority of the Yamal development is currently planned for the post-2020 period.
69. A clearly stated aim in the government's Economic Strategy is to prevent Gazprom from gaining control over gas distribution organizations (natural gas transport and/or delivery). See the Center for Strategic Research (2000), *Strategy of Development of the Russian Federation through 2010, Social and Economic Aspect*, submitted to the Government of the Russian Federation on May 25, 2000, Section 3.5.1.1
70. *Gazprom* pays for the right to use space in these foreign storage sites. The German site is owned by Wingas, a subsidiary of Wintershall AG and the Russian OAO Gazprom.

storage additions in 1993-98 were in the range of 9-13 Bcm. Gross storage additions nearly doubled during the 1990s from less than 30 Bcm in 1990 to more than 50 Bcm in 1999. Gazprom can place a significant quantity of gas in storage if solvent demand is not available. Compared with the position at the start of the 1990s, when storage additions and withdrawals were finely balanced, Gazprom now has some flexibility to decide whether to deliver more gas or to place more in storage.

Table 5.3 Russian Natural Gas Balance 1990-2000 (Bcm)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000*
Production	**639.8**	**642.7**	**640.4**	**617.8**	**606.8**	**594.9**	**601.0**	**570.5**	**590.7**	**590.8**	**584.2**
– Natural	601.0	608.0	609.0	588.7	581.0	570.0	575.0	543.7	564.1	563.5	555.3
– Associated	38.8	34.7	31.4	29.2	25.8	24.9	26.0	26.9	26.5	27.3	28.8
Storage (net)	– 5.1	– 2.5	– 1.1	– 12.7	– 18.8	– 15.9	– 14.0	11.5	– 5.3	– 0.1	6.9
Net exports	**179.7**	**177.5**	**188.3**	**164.4**	**182.4**	**187.1**	**193.0**	**196.4**	**200.4**	**201.2**	**217.9**
*To non-CIS***	*110.1*	*105.2*	*99.1*	*100.9*	*105.8*	*117.4*	*123.5*	*116.8*	*120.5*	*126.8*	*129.0*
Statistical difference	– 24.7	– 6.9	– 1.5	– 15.0	– 15.9	– 8.1	– 1.8	4.8	0.0	– 3.0	
Demand	**479.7**	**469.6**	**452.5**	**455.7**	**421.6**	**400.1**	**395.8**	**380.9**	**385.0**	**392.4**	**366.2**

** For 2000, data from Gazprom is used / ** Export breakdown taken from Gazprom data.*
Source: IEA estimates and statistics.

Investments in the Gas Sector

The Energy Strategy's gas-sector investment requirements for 2001-2020 (Table 5.4) total $164 to $171 billion. The annual requirements gradually increase from $7 billion per year during 2001-05 to $10 billion annually during 2016-2020. By these standards, Gazprom's estimated investment programme of $3.1-$3.6 billion per year for 1999-2000 would be too low for 2001-05 and would fall far short of investment requirements for the entire period. In the future, Gazprom will be only one of the companies – albeit by far the largest – investing in gas production. It is uncertain whether competitors will bid to build new transmission capacity. The table suggests that transportation requires slightly more investment than production for the entire period. For the period to 2005, the transportation requirement is 40% more than that of production. While investment requirements for production increase throughout the entire period, transportation requirements fall slightly and then increase after 2011. This probably reflects the timing of the pipelines which will connect the Yamal fields to the main trunklines and the building of new export pipelines in Eastern Siberia and the Far East. Unfortunately, the Strategy does not provide separate assessments of internal and export investment requirements.

Table 5.4 Projected Investments in the Russian Gas Sector, 2000-2020 ($ Billion)

Investments	2000	2001-2005	2006-2010	2011-2015	2016-2020	Total
Production	1.0	12-13	17	19	23-24	71-13
Transportation	2.2	18	17-18	20-21	22-23	76-80
Storage	0.4	3-4	4	5	6	17-19
Total	3.6	34-35	37-39	43-45	51-53	164-171

Source: "Energy Strategy of the Russian Federation to 2020" (MinEnergo, 2001).

Access Terms and Tariffs

Third-party access to transmission pipelines was introduced in 1997. An independent regulator – the Federal Energy Commission (FEC) – was assigned to oversee both the design and implementation of tariffs for inter-regional transmission and of tariffs set by Gazprom, which is considered to have a "natural monopoly" in transmission.[71] Before 2000 there were two transmission tariffs: $9 per thousand cubic metres per hundred kilometres ($9/000cm/100km) for deliveries to domestic customers and 80 cents/000cm/00km for deliveries to (CIS) export customers. In July 2000 the two were reduced to a single tariff: from 60 cents to one dollar per thousand cubic metres per 100 km. This action was clearly designed to improve incentives for independent producers to supply the Russian market. The basis of this tariff – how it was designed and revised – is not clear, but the significance of transparent tariffs in a country where most of gas needs to be brought several thousands of kilometres to domestic and export customers is obvious. For independent producers, the level of transmission costs is the most important determinant of the "economic radius" of production: the distance which gas can be transported from the point of production to a customer and still be sold at a profit. Transparency and non-discrimination in the application of transmission charges – ie how these have been calculated and the fact that they are being applied to all users, including the owner, of the pipeline – are essential prerequisites for the development of competition.

Gazprom's position is different: transportation charges are, in effect, an internal transfer price within the company (between the sales and transportation subsidiaries) and are not transparent. It is believed that Gazprom's internal transportation charges are between one-third and two-thirds of the regulated charges. If this is correct, it raises the issue of fair competition between Gazprom and independent producers.

Tariff levels are not the only issue for independent producers; access terms also have considerable importance. Two specific aspects of access terms have created problems over the past five years:

- Access for producers of associated gas (gas produced in association with oil). A major reason for the low use of associated gas is the regulated price at which oil companies must sell it to processing plants. Despite a trebling of this price in December 1999, in 2000, the average costs of gathering and transporting this gas, 250 roubles per thousand cubic metres (R/thousand M^3), was far above the maximum regulated sales price of 150R/thousand M^3.[72] As long as this situation persists, flaring remains the only viable alternative aside from sales of raw (untreated) gas to local power stations. In June 2001, the regulated price of associated gas was doubled to a range of 275R/thousand M^3 and maximum of R350/ thousand M^3. It remains to be seen whether this will be sufficient to increase utilisation. Gazprom owns processing plants at Orenburg and Astrakhan. The Siberian-Urals Oil and Gas Chemical Company (Sibur) owns nine major Siberian gas-processing plants. Sibur has *de facto* monopsony purchase rights in Siberia and purchases associated gas from oil companies at regulated (low) prices. Producers, however, would prefer to receive a fair price for their gas being processed

71. In 2001, it was announced that the FEC was to be replaced by a new unified regulatory body. But it appears that this new body will still be called the FEC although its responsibilities will be substantially increased. There are also 80 regional energy commissions.
72. *Interfax Petroleum Report*, 3-9 November 2000. A working group has been formed within the Duma Committee for Energy Transportation and Communications to draft a bill on the regulation of associated gas.

in Siberia. It was revealed in October 2000 that Gazprom had made a take-over bid for Sibur and purchased 51% of the company's equity. Since this would create a gas-processing monopoly, permission for the sale was needed from the Antitrust Ministry. It appears to have been forthcoming, albeit with stringent conditions attached, notwithstanding that the deal contravenes stated policy in the government's Economic Strategy.[73]

- Identification of spare capacity in Gazprom's transmission system. At present, regulators cannot independently verify whether capacity exists in the transmission system to carry third-party gas. By law, 15% of the capacity of the transmission system is reserved for independent shippers. Clearly there is an incentive for Gazprom to refuse to transport third-party gas, as such transportation would be to its commercial disadvantage.

►►► **Gazprom*'s take-over of Sibur is not desirable and should be further examined by regulatory authorities.*** *Arrangements should be made for ensuring that* Gazprom/*Sibur is not able to abuse its dominant position in gas processing. A complete new regulatory regime should be developed for associated gas, including regulated prices (as an interim measure before market prices are established), third party access to processing plants and regulated charges for gas processing.*

From the introduction of *third party access* (TPA) in 1997, access terms were the responsibility of an inter-departmental committee, but in November 2000 a Commission on Access to Oil and Gas Pipelines, headed by a first deputy prime minister, was created.[74] Shortly after the creation of the commission, in January 2001, a prime-ministerial resolution was issued covering the regulation of all prices and tariffs for gas transportation throughout the entire industry.[75]

On State Regulation of Gas Prices & Tariffs for Gas Transportation in the Russian Federation (Resolution No. 1021, 29/12/2000)

The principles to carry out state policy in the regulation of gas distribution were approved by the government in the "*Main Provisions of the Formation and Government Regulation of Gas Prices and Tariffs for Gas Transportation in the Russian Federation".* All organisations involved in the production, transport and sale of natural gas must maintain separate records of products, services and production costs for the following activities:

- production of natural gas;
- pipeline transportation of natural gas;
- storage of natural gas;
- delivery and sale of natural gas.

73. *Interfax Petroleum Report*, 27 October-2 November, 2000. A clearly stated aim in the government's Economic Strategy is to prevent Gazprom from gaining control over the processing of casing head petroleum gas. See the Centre for Strategic Research (2000), *Strategy of Development of the Russian Federation through 2010, Social and Economic Aspect*, submitted to the Government of the Russian Federation on 25 May 2000, Section 3.5.1.1
74. *On the Russian Federation Government's Commission on Issues of Utilising Trunk Oil and Gas and Products Pipeline Networks*, Resolution No. 843, 2000.
75. *On Gas Supply in the Russian Federation*, Resolution No 1021, 2001. www.economy.gov.ru/pr2.html

The principles for setting prices for gas and rates for transportation were defined. State controls for wholesale gas prices and tariffs for transportation for independent companies will be used until state controls for all suppliers are introduced. The state will gradually move from control of wholesale gas prices to control of tariffs for gas transmission.

This resolution sets out a regulatory framework to be introduced in two stages during 2001. The first stage covers:

- transfer to state regulation of wholesale prices for gas and state regulation of tariffs for gas transportation by independent companies;
- developing a charging methodology for transmission and distribution tariffs;
- organisation of one or several gas transmission companies to transmit through major trunk pipelines; and
- introducing separate recording of services and costs of services.

The second stage will be the preparation of the basis for price liberalisation and the defining of boundaries for state regulation of the gas sector. The regulatory institutions responsible for this work will be the Federal Energy Commission (FEC) and Regional Energy Commissions (RECs). The FEC will regulate:

- production of natural gas;
- pipeline transportation of natural gas;
- storage of natural gas;
- delivery and sale of natural gas.

The principles for setting prices for gas and rates for transportation were also defined. Using tariff methodology devised by the FEC and approved by the RF Ministry of Economic Development and Trade, the FEC has the power to delegate to RECs the implementation of:

- retail prices for gas used by residential and district co-operatives;
- tariffs for services provided by distribution companies;
- payment for supply services provided by distribution companies.

Fixed prices and tariffs will be set, with the aim of achieving:

- favourable conditions for self-financing by companies;
- a defined level of profitability, until the size of the cost base and other costs are determined;
- meeting solvent demand for gas;
- all taxes and other required payments;
- differences in cost of services to customers in different regions;
- promoting competition in gas supply and between gas and other types of fuel.

As this book was being prepared, the Ministry of Economic Development and Trade, the FEC and Gazprom were to submit proposals on a time frame for switching to government control of transport tariffs.

Resolution 1021 provides a good basis for predictable and transparent regulated prices and regulated access to networks and other gas transportation services. However:

- The first quarter of 2002 is likely to be the earliest that regulation can be fully introduced. Even then, it is not clear from the resolution when the distinction will be abolished between those tariffs which Gazprom will pay for transmission and those tariffs which will be paid by independent companies using Gazprom's network. Likewise, independent transmission companies will have a different tariff structure from that applied to Gazprom's network. The resolution anticipates a transitional regime until tariffs can be applied in a non-discriminatory manner to all parties using a network, irrespective of the ownership of that network. It is unclear how long that transition will last.
- The decree appears to deal only with natural gas. As to associated gas, the problems identified above – prices and charges for processing and transportation – will presumably form part of other legislation or regulation.
- Neither of the decrees (on establishing the Commission and on regulation of access) has specific provisions requiring the owners of transportation or processing facilities to provide documentation on their available capacity in the event of a refusal to provide access.

►►► ***The new regime for gas prices, transmission tariffs (including methodologies) and access terms needs to be developed as soon as possible.*** *Specifically, the definition and allocation of available pipeline capacity, and non-discriminatory terms for the use of the transmission system, need to be developed urgently. There is a lack of clarity as to the roles of the FEC and the Commission on Access to Oil and Gas Pipelines as to wholesale prices and tariffs. There is also uncertainty as to the time frame within which* Gazprom *transmission subsidiaries will apply the same access rules and charge the same tariffs to other* Gazprom *subsidiaries as they do to third-party network users. This should be clarified with the aim of introducing non-discriminatory rules and charges as soon as possible but certainly within three years.*

Supply and Transportation: Summary

There is no shortage of either gas reserves or transportation capacity and there is unlikely to be any in the near future. Commercial companies with scarce investment capital have no reason to investment it new facilities unless they can anticipate positive returns. Even investments to refurbish and renew existing facilities must meet this test. In the Russia of 2001, the prospect for such returns is unclear. There remain major uncertainties about prices, payments, payment terms, taxation and the new regulatory framework. Unless a more stable and attractive environment emerges in the first decade of the 21st century, few companies, domestic or foreign, will try to challenge Gazprom and its affiliates.

THE RUSSIAN MARKET: DEMAND, PRICES, PAYMENTS AND TAXES

The economic and commercial basis of gas sales within Russia is extremely complicated. There is little reliable data on how much gas is delivered to different groups of consumers.

There is no detailed and consistent information on the payments that consumers make for their gas – whether they pay at all, the percentage of payment, the timeliness of payment and what consumers pay with: money, barter or some other instrument.

Table 5.5 shows Russian gas demand by sector for 1990-1999. During that period, gas demand fell by 18%, reaching its lowest point in 1997. From 1995 to 1999 demand was roughly stable. This is an extraordinary figure given the general economic contraction during this period.

Table 5.5 Russian Gas Demand by Sector 1990-1999, in Bcm

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Demand	**479.7**	**469.6**	**452.5**	**455.7**	**421.6**	**400.1**	**395.8**	**380.9**	**385.0**	**392.4**
Heat & power*	**281.9**	**280.9**	**269.3**	**264.3**	**249.9**	**235.3**	**234.4**	**230.3**	**225.5**	**229.8**
Energy sector	8.5	7.9	7.6	8.5	9.5	10.6	11.9	9.3	13.7	13.6
Distribution losses	12.1	7.7	7.3	7.3	8.1	7.9	8.3	6.7	7.2	7.2
Total final consumption	**177.2**	**173.2**	**168.3**	**175.6**	**154.0**	**146.3**	**141.2**	**134.6**	**138.5**	**141.8**
Total industry	**63.9**	**66.6**	**64.6**	**59.7**	**47.0**	**49.2**	**46.7**	**48.2**	**44.1**	**46.6**
Non-specified (industry)	2.1	2.0	1.9	0.4	0.4	0.3	0.9	1.0	1.1	1.2
Total transport	**42.2**	**41.7**	**42.0**	**40.6**	**39.0**	**36.4**	**35.4**	**29.9**	**38.3**	**38.0**
• Road	1.4	0.8	1.3	0.7	1.0	0.4	0.3	0.2	0.2	0.2
• Pipeline transport	40.8	40.9	40.7	39.9	38.1	36.0	35.1	29.7	38.1	37.8
Total other sectors	**71.1**	**64.9**	**61.6**	**75.3**	**68.0**	**60.7**	**59.2**	**56.5**	**56.1**	**57.2**
Commerce – Public services	10.9	10.6	9.7	7.9	6.5	5.4	4.4	3.6	3.0	3.0
Residential	58.3	52.6	50.3	65.5	59.6	53.5	53.0	51.1	51.5	52.4
Agriculture	0.7	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.7	0.8
Non-specified (other)	1.2	1.1	1.1	1.1	1.0	1.0	1.0	0.9	0.9	0.9

** includes auto-produced heat and power.*
*** Gazprom statistics for Russian gas demand for the year 2000 show a 3% increase over 1999. Due to very different methodologies, it is impossible to compare the sectoral breakdown with IEA statistics. See statistical annex for more details.*
Source: 1990-1991 IEA estimates; 1992-1999 IEA statistics.

Table 5.5 shows that power generation and industry account for almost 80% of total demand. Despite much-publicised arguments between the Chairmen of Gazprom and UES, with threats by the former to cut gas supplies to the latter's power stations, gas supplies to power stations remained roughly stable[76]. Gas demand of individual industrial sectors fell. Despite some increase since 1998, demand has yet to regain the volume of the early 1990s. The share of residential and municipal gas demand, including district heating, is still relatively low, although slowly increasing.

Pipeline Fuel, Losses and Leakage

This is one of the most difficult areas of the Russian gas balance about which to obtain information. IEA statistics shown in Table 5.5 contain a figure for "pipeline transport" but it is not clear what is included aside from gas used for compression. To this figure it would seem appropriate to add "Distribution losses" and "Energy sector" to better

76. Gazprom's preliminary data for 2000 shows even a slight increase in natural gas supplies to the electricity sector.

estimate overall "Pipeline fuel, losses and leakage". The International Gas Union has estimated total leakage of methane from the Russian gas chain in the following proportions: production and processing 12%, transmission and storage 65% and distribution and end-use 23%. For 1998, Gazprom estimated leakage from its high-pressure pipeline network at eight Bcm or 1.4% of total throughput (Table 5.6).[77] This does not take account of gas that may have been vented (released without burning) prior to reaching the pipeline network.

Table 5.6 Greenhouse Gas Emissions from Gas Industry Operations 1998

	Methane Bcm	Global Warming Potential (Million Tonnes of Carbon Dioxide Equivalent)
Leakage from production, High-pressure pipelines & compressor stations	8	114
Fuel use at compressor stations on high-pressure pipelines	42	87
Total Gazprom emissions	**50**	**201**
Leakages during distribution*	5	66
Total gas industry emissions		**267**

** Assumed as one-third larger than figures attributed to Rosgazifikatsia in, IEA (1995), "Energy Policies in the Russian Federation", p. 171.*
Source: Moe and Tangen (2000), Table 6.1, p. 84.

Gazprom's statistics on pipeline "failure rates" show constant improvements over the past two decades. In 1999, the rate stood at 0.18 failures per thousand kilometres.[78] Furthermore, the company claims that since 1995, over 40% of the network has been subjected to internal leak-detection analysis.[79] Data on leakage and losses from the high-pressure transmission system is very sketchy. But there are almost no such data for the low-pressure distribution networks. One source assumes that leakages in distribution in 1998 were five Bcm, but this is probably an under-estimate.[80] As mentioned above, very little investment has been available to distribution companies, most of which have been in serious financial difficulty. Lack of equipment for metering and measurement compounds this problem.

Prices and Payments

Table 5.7 shows the official prices charged to Russian industrial and residential customers, in comparison with average European import prices from 1991 to 2000. During the period of high inflation in the early and mid-1990s, prices rose very rapidly for all domestic customers, partly to keep pace with inflation and partly to reflect the much higher prices received for exports to Europe. Following the economic crisis and rouble devaluation of 1998, however, prices barely kept pace with inflation even in rouble terms. In dollar terms they fell to a quarter of their mid-1990s value.

77. Arild MOE and Kristian TANGEN (2000), *The Kyoto Mechanisms and Russian Climate Politics*, Royal Institute of International Affairs, Table 6.1, p. 34.
78. Gazprom *Annual Report*, 1999, p.24. The wording in the report is 0.18 accidents per 1000 km.
79. 62,700 km out of 150,000km has been subjected to so-called "intelligent pigging" including 14,200 km (9.5% of the system) in 2000. Gazprom *Annual Report, 2000, p.35.*
80. Moe and Tangen, *loc.cit.*

Table 5.7 Russian Natural Gas Prices 1991-2000

	Export* (Europe) $/ Thousand M^3	Industry Rubles/ Thousand M^3	Industry $/ Thousand M^3	Residential Rubles/Month
1991	91.8	52	10.4	
1992	89.7	1,100	2.7	3.40
1993	88.3	21,875	17.6	29.0
1994	83.0	73,773	21.6	65
1995	95.0	257,151	55.7	951
1996	93.5	289,176	52.2	1,184
1997	99.5	327,000	54.9	2,449
1998	82.2	338	16.4	3.18
1999	62.1	371	13.7	3.74**
2000	116	390	13.7	4.30**
2001 (Q1/Q2)	136	460**	14.5**	5.38**

** Weighted average import prices into Germany $/ thousand M3 / ** estimates.*
Source: Goskomstat.

In the Russian market, prices for industrial customers have always been significantly higher than those charged to residential and municipal customers. Residential prices were a fraction of the industrial price up to the mid-1990s. By 2001 – despite a stated policy to raise them *above* industrial prices – they had still not even achieved parity. Pricing of gas for residential customers is anything but straightforward:

- there are multiple price sub-categories; pensioners and war veterans pay less than the official price level;
- a large proportion of residential gas is used in the form of heat from district heating systems;
- residents often cannot adjust heating systems because of lack of temperature control in individual apartments;
- there is little individual metering for gas or heat; monthly gas fees are paid as part of rent;
- physical disconnection of individual apartments for non-payment is usually impossible because of legal and technical constraints.

Because of these special conditions, there is no price elasticity for heat or gas supplies to residential customers. There can therefore be no demand response to any change in price. Consumers cannot obtain information as to how much gas they are using and have no control over their own consumption. This situation is only slowly being addressed through the installation of thermostatic controls and meters. Fundamental problems of building design make the installation of controls and meters highly capital-intensive and commercially unattractive.

For these and other reasons, and because residential/municipal gas demand represents less than 15% of total demand, and the record of payments – particularly cash payments

– has generally been better than for many other groups of customers, the urgency of reform in this sector is perhaps less than is generally believed. This does not mean that it is impossible to reform the price and payment conditions of residential gas customers. If vulnerable groups such as pensioners and veterans need help with their fuel payments, this can be addressed through direct payments. It should not provide a pretext for continuing price distortions. Even so, a higher priority should be placed on reforming price and payment conditions for businesses, where the problems are much larger and are easier to rectify.

After the 1998 economic crisis, industrial prices in dollar terms plummeted to \$10/Mcm, then recovered to around \$14/Mcm in late 2000 (Table 5.7) and around \$14.50/Mcm in the first half of 2001.[81] It is uncertain whether the 1995-99 prices – even when paid promptly and in cash – covered the operating costs of production and transportation of gas for customers in the west of Russia. Certainly, they were close to break-even prices for Gazprom. They provided no incentive to develop new supply or infrastructure to serve Russian customers.

Gas prices have been kept artificially low not only in terms of what gas costs to produce and distribute, but also in comparison with the prices of other fuels. By the late 1990s, the price of gas for industrial users was 30% to 50% below that of coal and around one-third to one-quarter that of oil products. Naturally increasing numbers of users switched to gas. An urgent need developed for gas price increases.

In the period from 1992 to 1995, when prices were raised nearly to market-related levels, there was a massive increase in non-payment and non-cash payment, principally by non-residential customers. Non-payment is a complex issue, as it includes many variants: partial payment, late payment, payment through barter, payment in various categories of non-cash financial instruments, payment offsets and the "netting off" of taxes with Federal and Regional authorities. Tables 5.8 and 5.9 attempt to capture some of these different categories from two different sources, Gazprom and the Russian statistical agency, *Goskomstat*. The Gazprom statistics show that from 1997 to 1999 "prompt cash" payment comprised much less than 20% of all payments made by customers. Gazprom reports that in 1999 it earned nearly 62 billion roubles from sales to Russian customers, and that the debts of those customers amounted to more than 101 billion roubles on 1 January 2000.[82]

At the beginning of 2000, according to Gazprom, accumulated receivables from Russian customers were huge – more than one year's receipts. The principal debtors were power generators, with 40% of the debts at the beginning of 2000; and federal government organisations (known in Russia as "budget-financed organisations"), with around 15%. Distribution companies accounted for most of the remainder. One year later, Gazprom's payment situation had improved dramatically. Total indebtedness of its customers had fallen by more than 20% although it still amounted to 80 billion roubles at 1 January 2001. Of this, power generators accounted for 35.8% and government organisations 12.6%.

81. In January 2001, the FEC approved an immediate increase in industrial gas prices of 18%, and a 25% increase in residential gas prices, effective in March 2001.
82. Gazprom *Annual Report and Accounts*, 1999.

Table 5.8 Breakdown of Payments by Russian Gas Consumers Percentage

	1997	1998	1999
Cash	12.4%	16.1%	18.5%
Marketable securities including	18.1%	26.2%	27.6%
• Liquid bank notes		10.0%	4.9%
• Federal tax netting		11.9%	15.7%
Barter	50.5%	22.2%	28.9%
Tax breaks and tax nettings	4.9%	22.2%	22.5%
Other	14.1%	13.3%	2.5%
Total	100 %	100%	100%
Total receivables due (Billion rubles)**	**82.4**	**102.9**	**108.3**

** payments received not "receivables" / ** Total receivables including non-payment.*
Source: Gazprom.

Table 5.9 Payments to Gazprom by all Customers, 1999-2000

	February-November 1999*	January-July 2000**
Industrial sales, rubles bn	19.8	41.3
Including in %:		
• Monetary payments	52.5	74.1
• Promissary notes	9.9	6.5
• Mutual offsets	14.2	8.8
• Barter	15.9	6.4
• Other non-monetary	7.6	4.2
Total***	**100**	**100**

**Average of nine months / **Average of seven months / ***may not add due to rounding.*
Source: Goskomstat.

Among the power generators, RAO UES is the principal debtor and it is, protected against disconnection partly by presidential decree, partly by the argument that its own non-payment crisis has been worse than Gazprom's and partly because of its size and political influence. During 2000, a series of well-publicised disputes between the two companies – included public exchanges between their chief executives – had to be mediated by the government. Gazprom warned that in future there would be less gas available for the power sector as a whole, and specifically for UES. In the event, deliveries to power plants remained stable (Table 5.6) and preliminary data from Gazprom shows a slight increase in 2000. The announcement by UES that from July 2000 those who failed to pay their bills would be disconnected has raised cash payment in the electricity sector. At the beginning of 2001, UES announced that henceforth only cash payment would be accepted.

The payment situation is equally complex for government organisations. In response to Gazprom's threat of discontinuation, the federal government made special provisions in the budgets of its organisations setting up a budget line for payments to utilities. Unfortunately, many government organisations simply spent their utility budgets on more urgent requirements, gambling that they would not, after all, be disconnected.

For Gazprom, which is still partly under state ownership, the political difficulties of cutting off state organisations are severe. Anecdotes abound of powerful individuals from federal and regional government who have telephoned the Russian president as a result of disconnection, pleading that he intercede with Gazprom on their behalf. By 2001, payment for gas of budget organizations had significantly improved. The introduction of the federal treasury system of registration of contracts for the supply of fuel and energy resources, including gas, as well as the system of agreements with the Ministry of Energy to limit the numbers of gas users, produced a considerable improvement in payment for gas by government organisations.

Tables 5.10 and 5.11 show that Gazprom's payment situation improved greatly in 2000. Although data are incomplete and available for only a relatively short time, Table 5.10 shows that the share of receivables paid to Gazprom by Russian customers rose from less than 50% to nearly 100% in the 3rd quarter of 2000. Table 5.11 shows that cash payments increased from an average of 40%-50% in 1999, to an average of 60%-70% in 2000.[83] In its Annual Report for 2000, Gazprom stated that Russian customers paid *122% of their gas bills,* including past debt, with cash payment increasing to 70%, compared with 39% the previous year. This does not mean that the payment situation has been actually resolved. The share of non-cash payments, even if down to 30%, is still too high. Further increases in the share of cash payment are essential for market signals to reach customers.

Table 5.10 Share of Receivables Paid to Gazprom, 2000, (%)

	Total	**Russian Consumers**
January	n/a	n/a
February	n/a	n/a
March	n/a	n/a
April	72.2	46.9
May	73.5	52.8
June	87.1	66.1
July	77.1	53.0
August	106.9	84.1
September	89.8	97.9

Source: Goskomstat.

The Lack of Demand Response

After the fall in economic activity prior to 2000, combined with fluctuations in prices and levels of payment, it is difficult to understand why gas demand did not drop more strongly during the 1990s (Table 5.5), and why it began to increase again after 1997. Even with the resumption of economic growth in Russia, a substantial increase in the level of cash payment and overall levels of payment could be expected to reduce demand. There are a number of explanations for the absence of such a response:

- despite price and payment increases, consumers are still switching to gas from other fuels because of its continued price advantage;

83. An interesting and unexplained feature of Tables 5.10 and 5.11 is the monthly variation in payment figures. The coverage of the data is too short to see whether a pattern emerges over the calendar year.

Table 5.11 Structure of Gazprom's Payment Receipts, 1999-2001, (%)

	1999		2000		2001	
	Cash	**Non-cash**	**Cash**	**Non-cash**	**Cash**	**Non-cash**
January	n/a	n/a	72.3	27.8	78.2	21.8
February	53.3	46.7	85.4	14.6	76.0	24.0
March	51.1	48.9	77.1	22.9	85.9	14.1
April	54.7	45.3	72.4	27.6	83.4	16.6
May	51.5	48.5	70.2	29.8	80.4	19.6
June	54.6	45.4	72.9	27.1	75.2	24.8
July	57.7	42.3	68.2	31.8	79.0	21.0
August	63.8	36.2	64.6	35.4	82.3	17.7
September	53.2	46.8	64.1	35.9		
October	46.6	53.4	73.8	26.2		
November	40.7	59.3	66.6	33.4		
December	n/a	n/a	67.0	33.0		

Source: Goskomstat.

- price-elasticity effects are relatively modest – or subject to several years' delay – and very large price increases are required to bring down demand;[84]
- barter and other non-cash payments continue to blunt the market signals of prices and payments;
- in a country as large as Russia, different regions and different industries will produce a matrix of elasticities rather than a single value.[85]

The price distortions and payment problems of the mid-to-late-1990s help explain why only a relatively small reduction in gas demand occurred in the immediate post-Soviet period, followed by an increase after 1998. Strong and sustained price reform may yet depress demand as industrial structures change and energy-efficiency projects become attractive. Price reform will also encourage interest in "joint implementation" projects under the Kyoto Protocol. One such example already exists in the Russian gas industry. Jointly with the German gas company, *Ruhrgas AG*, Gazprom has initiated a joint implementation project aimed at optimising long-distance natural-gas transmission in Russia. The first stage of the project resulted in annual reduction of fuel-gas consumption by 120 million M^3/year and of CO_2 emissions of 231,000 tonnes. If the project is extended, savings are estimated to amount to 1.5 million tonnes of CO_2.

Domestic Versus Export Prices

The problem of falling domestic revenues is clear from Gazprom accounts (Table 5.12). From 1996 to 1999, Gazprom revenues from domestic sales declined by 20%. By 1998 they were about 35% below the 1996 level. Rouble-denominated payment for exports to Europe doubled between 1998 and 1999, due mostly to the devaluation of the

84. Demand may be similarly price-inelastic in the electricity sector, which consumes a substantial amount of gas.
85. Igor Bashmakov (2001), *Energy efficiency: From Rhetoric to Action*, CENEF.

currency following the economic crisis of August 1998. This effect was even more pronounced because all European payments are in hard currencies, while a large proportion of Russian payments were in barter and other non-monetary instruments. So the ratio of rouble-denominated payments European and Russian customers widened from less than two-to-one in 1996 to nearly six-to-one in 1999, a year when European border gas prices reached a historical low. With the oil-linked export price of gas to Europe at around $136/Mcm in the first half of 2001 – the highest price seen for some years – the ratio of export to domestic price exceeded nine-to-one (Table 5.7).

Table 5.12 Gazprom's Sales to, and Receipts from, Different Market Sectors, 1996-99

	Russia			Europe		
	Volume (Bcm)	**Receipts (Rbn)**	**R/Thousand M^3**	**Volume (Bcm)**	**Receipts (Rbn)**	**R/Thousand M^3**
1996	302	79.3	263	123.5	60.1	487
1997	301.3	71.0	236	116.8	60.1	515
1998	293.7	50.4	172	120.5	73.3*	608
1999	299.8	61.9	210	126.8	155.1*	1220

** the increase in European receipts from 1998-99 was caused by a major ruble devaluation in 1998.*
Source: Gazprom Annual Report.

Domestic Price Reform

Table 5.13 shows price reforms that have been implemented or are proposed in the Energy Strategy for 2000-2007. The current price strategy foresees major price increases until 2007, when Russian domestic prices are expected to equal European export prices. This is an immensely challenging and important target, especially for the period to 2003-2005, when prices are meant to rise by 250%-350% to around $50-$55/Mcm.[86]

Table 5.13 Gas Price Reforms, 2000-2007

Date	**Price Increase %**	
	Industrial	**Residential**
Implemented		
May 2000	20	15
January 2001	18	
March 2001		25
Proposed*		
2003 (compared with 2000)	250	
2005 (compared with 2000)	350	
2007	Equivalence with European gas prices	

** "Energy Strategy of the Russian Federation to 2020", MinEnergo, 2001.*

It is uncertain whether these increases, accompanied by the elimination of non-payment and the enforcement of prompt cash payment, can be implemented without bankrupting some large companies and causing serious unemployment. Yet the overall rewards will be considerable in terms of:

- unlocking the huge potential for energy efficiency, which can lead in time to demand reduction and consequent reduction in supply requirements;

86. How far prices will need to be increased after 2005 will depend on European gas import prices and the exchange rate of the rouble against the Euro at that time.

- providing opportunities and incentives for domestic and foreign companies to invest in gas supply, and in demand reduction, in the Russian market.

►►► ***The determination to increase gas prices is commendable but should be accompanied by mechanisms to deal with the problems that may arise.*** *Serious problems for individual industries and regions could include bankruptcies, high unemployment and dislocation. More detail is required on:*

- *whether companies that go bankrupt or experience serious financial difficulty will receive subsidies from the federal and regional governments, and over what period; and*
- *how rapidly companies will have to move from barter and other non-cash instruments to cash payments only. A regulated incentive to pay in cash could be considered for a transitional period.*

Absolute increases in prices will not solve all problems. The Energy Strategy also foresees an increase in the domestic prices of gas relative to coal, such that the ratio of coal to gas prices rises from the 1 to 0.7-0.8 of the late1990s, reaching 1-to1.2 in 2005 and 1-to-1.6-1.8 thereafter.

Much will depend on price reform. If it succeeds, it will provide incentives to invest in supply and transportation capacity to serve the Russian market. It will promote energy conservation and efficiency measures. It will allow the development of emissions trading and of the other market-based mechanisms of the Kyoto Protocol within the Russian gas sector. Price reform is probably the single most important policy for the gas – and perhaps the entire energy – sector, in the first decade of the 21st century.

►►► ***A clear plan and timetable for price increases should be established.*** *It should include quarterly price increases for each customer class, taking into account both inflation and export prices. Prices to residential customers should be raised as soon as possible to levels higher than for industrial and power-generation customers. (It should be recognised, however, that so long as residential consumers cannot control their consumption of gas and the heat generated from gas, it will be unacceptable to raise prices beyond a certain level).*

Taxes

Gazprom accounts for around 25% of Federal tax receipts. Its chairman has claimed that tax and other payments to government amounted to 45% of the wholesale price of gas in 1999. They are estimated to have exceeded 50% in 2000. Excise tax accounts for more than half of the tax take. The excise tax rates in force in 2001 were15% for sales to Russian industrial customers and utilities (household sales are exempt); and 30% for exports to all export markets.

In July 2000, excise tax exemptions on independent producers were removed. This move makes independent development of new fields much less likely. Since 1999, a combination of high excise taxes and low regulated prices has made it impossible for gas from Central Asia or the Caspian region to be sold profitably in Russia.

EXPORTS, JOINT VENTURES, EXPORT PIPELINES AND GAS TRANSIT

Historically Russia exports gas to two main markets: the CIS and Baltic countries, and European countries. The historical distinctions were political, commercial and institutional. With the passing of the Cold War the political distinction lost relevance. The commercial distinction between the Baltics and European customers is only partly relevant because the Baltic countries now pay in hard currency. Yet the institutional divisions remain. All Russian gas sales outside the CIS and Baltic countries are sold by Gazprom's export affiliate, Gazexport. Gazprom still handles some sales to the CIS and Baltic countries, but Itera is increasingly taking over these markets. There are strong logistical links between the two sets of markets. In the past; more than 95% of Russian exports to European countries, or 125 Bcm in 2000, flowed through pipelines in Ukraine. In the post-Soviet era, many problems have surrounded this huge volume of transit gas. Gazprom has sought to develop alternative routes – notably via Belarus and across the Black Sea to Turkey – to avoid these transit problems.

CIS and Baltic Countries

Table 5.14 shows the decline of gas deliveries to the CIS and Baltic countries since the break-up of the USSR. Those exports dropped from over 100 BCM in 1992 to just over 70 Bcm in the mid-1990s. The fall in deliveries resulted from the reduced economic activity throughout the region. Companies in the CIS were unable to pay the prices in money or on other terms acceptable to Gazprom. In the CIS, especially in Ukraine, Belarus and Moldova, payment problems have caused periodic curtailments, on some occasions amounting to a total cessation of supplies for several days.

Table 5.14 Russian Exports to Former Soviet Republics, 1993-1999, (Bcm)

	1993	**1995**	**1996**	**1997**	**1998**	**1999**
Ukraine	54.7	52.9	51.0	56.9	54.8	60.9
Belarus	16.4	12.9	13.7	15.7	15.8	16.5
Moldova	3.1	3.0	3.2	3.4	3.3	2.8
Other	1.2	0	0.6	1.7	3.3	4.1
Total CIS	**75.4**	**68.8**	**68.5**	**77.7**	**77.2**	**84.1**
Baltic countries	3.3	4.4	4.5	4.1	4.3	4.4
Total	**78.7**	**73.2**	**73.0**	**81.8**	**81.5**	**88.5**

The recovery of exports to the CIS since 1999 has largely taken the form of re-exports of Central Asian gas, principally from Turkmenistan, delivered by Itera. Indeed, the recovery of Russian exports to CIS countries has been a direct result of the rise of Itera as a major player. Table 5.15 shows exports to CIS countries in 2000 by Gazprom and Itera. The latter has taken over nearly half of these exports. Gazprom's remaining major market is Ukraine, which pays for its imports by transiting gas to European countries. In 2000 this has had the effect of dramatically reducing the indebtedness of CIS countries to Gazprom, with Belarus and Moldova paying 100% and 120% of their bills and Ukraine 90%.

Intra-CIS gas trade since the break-up of the Soviet Union can be divided into two periods. The first began in 1992 with a fall in Turkmen gas deliveries, their virtual disappearance during 1997-98 and partial replacement by Russian gas. The second, since the end of 1999, has seen the re-appearance of Turkmen gas in large volumes. Some of it is sold under contract to Itera, which then on-sells it mostly in Ukraine but

Table 5.15 Gazprom and Itera Exports to CIS and Baltic Countries, 2000, (Bcm)

	Gazprom Exports	Itera Exports*	Total Exports
Ukraine	27.2	32.4	59.6
Belarus	10.8	5.8	16.6
Moldova	1.8	0.6	2.4
Georgia	0	1.0	1.0
Armenia	0	1.4	1.4
Azerbaijan			0.3
Lithuania	2.0	0.6	2.6
Latvia	1.0	0.4	1.4
Estonia	0.6	0.2	0.8
Kazakhstan	0	2.7	2.7
Uzbekistan			0.2
Total	**43.4**	**45.0**	**88.9**

** not including supplies to Russia.*
Source: Gazprom and Itera.

also to other CIS countries, excluding Russia. The rest is sold directly to Ukraine, with Itera responsible for transportation. Crucial to this trade is the transportation of Turkmen gas through Uzbekistan, Kazakhstan and Russia. Transit conditions and tariffs in these countries need to be set at levels which allow Turkmen gas to remain commercially viable, especially in Ukraine. The reinstatement of Turkmen deliveries, as well as smaller volumes from Uzbekistan and Kazakhstan, suggests that Central Asian countries (and possibly Azerbaijan as well) can continue selling large amounts of gas to Russia. Some of that gas could move on via Russia to CIS and even European countries. In view of its successes in 2000-2001, Itera will probably be able to go on supplying gas from Turkmenistan[87] to these markets.

Because of changes in the tax and regulated price regime in Russia, imports of gas from Central Asian and Caspian countries could be cheaper than developing new Siberian gas fields. As discussed above, the resumption in 1999 of large-scale Central Asian deliveries to other CIS countries, especially Ukraine, is extremely beneficial for Gazprom and the Russian government. Gazprom is responsible only for supplying transmission *capacity*, for which it receives revenues and does not have to supply *gas,* for which payment may not be forthcoming. By trading gas for transit rights, Russia avoids constant, very difficult negotiations with the Ukrainian government about non-payment for gas supplies.

Itera's crucial role in developing and maintaining the transit of Central Asian gas to the CIS will help determine the attitudes of Gazprom and the Russian government towards the new company. The onward transit and sale of Central Asian gas to *other* European destinations will, however, mean competition for Russian gas exports. This

87. Azerbaijan organised an open tender won by a joint venture of *Itera* and the German company Ditgas (in which Gazprom holds equity). Itera took over supplies to a Georgian power plant when a combination of commercial and political problems arose with the supplier, Intergazstroi, in 2001.

will not be seen to be in Russian commercial interests. This in turn may educe more resistance from Gazprom to Russian ratification of the Energy Charter Treaty[88] and the Transit Protocol. Other factors in this complex situation are:

- the increased probability that existing Russian natural gas infrastructure will be used to improve energy flows, including the increased use of cross-border energy swaps;
- the reduced probability of disputes over transit, through the establishment of a minimum international legal standard for the transit of natural gas and the transparent international dispute settlement mechanisms found in the Transit Protocol;
- the possibility of avoiding political considerations when making energy-structure decisions of and increasingly basing such decisions on purely commercial grounds in Russia and her neighbour states.

Europe

Gazexport, the sole exporter of Russian gas to Europe, currently exports to 19 countries (see Table 5.16 and Map 6). Preliminary indications are that 130 Bcm was delivered to European countries in 2000. By 2008, Gazexport has long-term contracts to deliver 200 Bcm. Some of these contracts run to 2025.[89] About 80% of currently contracted volumes are long-term, the other 20% is annual. But Gazprom's stated policy in 2000 was not to sign any additional long-term contracts with European customers until at least 2008. From Gazprom's perspective the reasons behind this decision are that:

- european companies and governments will not wish to increase their dependence on a single source of supply;
- additional long-term contract gas would require more pipeline capacity and more borrowing;
- new gas production will be expensive; in a liberalised market, buyers may not be willing to pay a price that will cover the necessary investment.

The EU-Russian Federation Energy Dialogue launched in 2000 may have some impact on these perceptions.

European gas-market liberalisation will affect Russian exports to Europe. The traditional long-term, take-or-pay contractual structure will come under pressure. Traditional pricing of gas against alternative fuels – principally but not exclusively oil products – is likely to be replaced by short-term "spot" prices as gas-to-gas competition increases. These trends are expected to drive down prices from the oil-linked levels reached in late 2000 and early 2001. While long-term contracts will remain standard, pricing formulas will change, with the period between price revisions becoming shorter.

From the Russian perspective, not all these changes will be for the worse. New market opportunities will open up – swap transactions for example. Gazprom has devoted considerable study to the effect of liberalisation and competition caused by the EU Gas Directive. The company has set up a large number of joint-venture marketing

88. Ratification of the Energy Charter Treaty would provide a common tariff basis for gas transit from and through the CIS countries, including the Central Asian states. It would provide all parties with an international legal foundation – including a mechanism for international dispute settlement – on which to base transit grievances and receive compensation for transit violations. See Annex A for more details.
89. This assumes that long-term contracts for around 25 Bcm/year of gas, which expire in 2000-2008, will be prolonged.

Table 5.16 Russian Natural Gas Exports to Europe 1995-2000, (Bcm)

	1995	1996	1997	1998	1999	2000
Former Yugoslavia	2.0	4.0	3.9	3.7	3.1	3.5
including:						
"Yugoslavia"		2.11	2.06	1.80	1.1	1.5*
Croatia		0.97	1.14	1.20	1.2	1.7**
Slovenia		0.49	0.50	0.50	0.6	
Bosnia		0.42	0.14	0.20	0.2	0.3
Macedonia			0.001	0.002	0.04	0.1
Romania	6.1	7.15	5.09	4.70	3.2	3.2
Bulgaria	5.8	6.03	4.95	3.80	3.2	3.2
Hungary	6.3	7.71	6.52	7.30	7.4	7.8
Poland	7.2	7.14	6.75	6.90	6.1	6.9
Czech Republic	14.9	9.44	8.43	8.60	7.8	7.5
Slovakia		7.04	7.09	7.10	7.5	7.9
Total Central/Eastern	**42.3**	**48.5**	**42.7**	**42.2**	**38.3**	**38.7**
Greece	0.01	0.16	0.90	1.5	1.6	
Turkey	5.7	5.63	6.70	6.70	8.9	10.3
Finland	3.6	3.73	3.64	4.20	4.2	4.3
Austria	6.1	6.02	5.57	5.70	5.4	5.1
Switzerland	0.4	0.39	0.40	0.40	0.4	0.4
France	12.9	12.35	10.91	10.90	13.4	12.9
Italy	14.3	13.99	14.22	17.30	19.8	21.8
Germany	32.1	32.87	32.52	32.50	34.9	34.1
Total Western	**75.1**	**75.0**	**74.1**	**78.5**	**88.5**	**90.3**
Totat Europe	**117.4**	**123.5**	**116.8**	**120.5**	**126.8**	**129.0**

** Yugoslavia and Bosnia / ** Slovenia and Croatia.*
Source: Gazprom.

affiliates in European countries. Gazprom has already entered into two contractual arrangements which demonstrate its growing preparedness for the evolution of the market in Europe:

- its participation in the (British-Belgian) Interconnector UK pipeline will give the company the opportunity to trade gas both on its own account and as part of a tripartite trading agreement with Wingas and the British marketing company Centrica;
- under a flexible export contract with the Dutch company *Gasunie*, to provide up to four Bcm/year to Gazprom's European customers, under what will be essentially a swap arrangement will provide additional flexibility and security for Russian gas.

Joint Ventures

In 1990, Gazprom set up the first of its joint-venture marketing companies with Wintershall, a wholly-owned subsidiary of BASF, a German transnational chemical company. The resulting company, Wingas, owned 65% by Wintershall and 35% by Gazprom, has become a substantial transmission, storage and marketing company in Germany. A separate joint venture between the two companies, WIEH, sells gas in south-eastern Europe. The Wingas joint venture was the first of many set up over the past decade. Gazprom now has joint ventures with companies in virtually every country where it sells gas. Some of these are for gas sales, such as Gasum (Finland), Promgaz (Italy) and Panrusgas (Hungary). Others are for specific pipeline projects, such as Europolgaz for the Polish sector of the Yamal pipeline and the Blue Stream pipeline across the Black Sea to Turkey. A number of non-gas joint ventures has been set up to purchase project-related materials and other goods.

Outside Europe, Gazprom is involved in joint ventures in Iran and India. In Iran, it is a partner in the South Pars development, where it expects production to commence in 2002. In India, it intends to become involved in exploration and production, and in the proposed Iran-India offshore gas pipeline. It is also involved in gas development in Vietnam. These projects demonstrate Gazprom's interest in becoming a more international company, developing production and trading interests outside its immediate market area. This could bring higher returns than further development of its regulated domestic business.

New Pipeline Projects and Transit

Gazprom has encountered serious transit problems in its exports to Europe. As mentioned above, until 1999 more than 95% of deliveries to countries outside the CIS and the Baltic States moved through Ukrainian pipelines. Gazprom has had severe payment difficulties in relationships with CIS, particularly Ukrainian customers. The particular problem in Ukraine has been that when Ukrainian companies have been short of gas – often as a result of curtailed supplies due to non-payment – there have been unauthorised diversions of transiting Russian gas to Europe. Ukraine has officially confirmed 8.2 Bcm of unsanctioned removals of Russian gas in 2000[90]. The 2001 gas agreement between Russia and Ukraine created a mechanism to convert non-payment for gas into long-term Eurobond debt denominated in dollars.

Transit problems in Ukraine have been the main reason for Gazprom's move towards diversification of export routes. Its strategy has been to create new routes – two northern and one southern – to avoid transit countries, especially Ukraine. Its longer-term strategy calls for no more than 40% of its exports to transit through a single country.

Northern Routes

Yamal. The Yamal pipeline was originally designed as a six-line project bringing gas from fields on the Yamal peninsula, with four lines serving the Russian market and two export lines taking gas through Belarus and Poland to Germany and onward to other European countries. Following the break-up of the USSR and subsequent economic restructuring and decline, the project changed dramatically. The link to the Yamal fields will not now take place until 2016 at the earliest. An export pipeline, supplied with gas from existing Siberian production and running from the Torzhok compressor station north east of Moscow to the German border via Belarus and Poland, was completed in 1999. This line delivered 10-14 Bcm of gas to the German market in 2000. Its capacity will rise to 28 Bcm when it is raised to full compression around 2003. The Yamal name has been retained.

The Yamal "Link" (from Poland to Slovakia). By 2000, the question of when the second Belarus-Poland export line would be built had been overtaken. Gazprom turned to the more urgent task of speeding up the diversification of exports away from Ukraine, while continuing to use the capacity of the existing Slovak-Czech pipeline network. This could be achieved by creating a link between the Polish section of the Yamal pipeline and the existing Slovak export pipeline network. In this way, gas could be

90. Statement by Ukrainian Deputy Prime Minister O. Dubinin, *Interfax Petroleum Report*, March 30-April 5, 2001, p.20.

delivered to European customers by the traditional route, but through a system which circles Ukraine. A proposal made in late 2000 was for a Poland-Slovak "link" pipeline to carry 30 Bcm, with the possibility of an additional pipeline that could increase the volume to 60 Bcm. It is hard to project a time frame for the "link" pipeline. It will depend heavily on the involvement of international companies as co-funders and owners of transmission capacity and on political acquiescence by participating governments. Whereas Russia and Slovakia have come to an agreement, Poland, for example, insists that such actions should not harm Ukrainian interests. (see Map 5).

North TransGas/Nordic Gas Grid. An alternative to building a second Belarus-Poland line parallel to the first, would be the North TransGas (NTG) project, a 50-50 joint venture between Gazprom and Fortum of Finland. The NTG project envisages two different options for a pipeline running from a coastal point north of St Petersburg to Greifswald in northern Germany – either a sea route, with spur lines supplying Finland and Sweden, or a combination land-and-sea route through Finland and Sweden (see Map 5). There are two or three different variants of the exact route for each option. The Nordic Gas Grid (NGG) project, based on an EU-sponsored feasibility study, contains many of the same routing proposals but is sponsored by a different group of companies.

A NTG/NGG route for a new Russian export line would increase the attractiveness of developing the Shtokmanovskoye field in the Barents Sea. While Shtokmanovskoye could be developed to supply the Yamal pipeline corridor, there would be a geographical advantage in connecting it with an NTG/NGG pipeline. But this option is much more expensive than a land pipeline. Using Shtokmanovskoye as the supply source would add further major costs to the project.

The Southern Route: Blue Stream

Turkey is one of the world's fastest growing gas markets. Russian gas fed this market in the late 1980s, when a pipeline was built through Ukraine, Moldova, Romania and Bulgaria to western Turkey. With a huge expansion of gas demand expected in the country, principally for power generation around Ankara and in the west, the obvious solution would have been to expand the capacity and extend the length of the existing route. During the 1990s, however, Gazprom's problems with gas transit through Ukraine caused severe disruption to Turkish supplies on more than one occasion. Gazprom also experienced problems in negotiating transit terms and conditions with Bulgaria. These difficulties, combined with the risk that Turkish buyers would question the reliability of Russian supplies, led Gazprom to seek a route that would eliminate transit countries. This was the rationale behind the Blue Stream pipeline (see Map 7).

Greeted with a certain amount of incredulity in 1996 when it was announced by Gazprom, Blue Stream involves building a 374 km pipeline across the Black Sea from Dzhubga on the Russia coast to Samsun in northern Turkey, with an onward land pipeline to Ankara. The Black Sea section will be laid at a depth of 2,150 metres – deeper than transport pipe has hitherto been laid – where the water has a high concentration of hydrogen sulphide, which can cause additional corrosion problems. Scepticism surrounding the project was somewhat allayed in 1999 when ENI, the Italian conglomerate, entered into a 50-50 joint venture with Gazprom to build the pipeline, which will have an ultimate capacity of 16 Bcm/year.[91] With contracts and financing completed, the land pipeline has been laid. Laying of the Black Sea section started in August 2001, with the first gas planned to arrive during the first quarter of 2002. The project is being hurried to completion not only because Turkey's need for gas to meet demand, but also because of potential competition. Other gas pipeline projects are in the making – from Iran, Azerbaijan and/or Turkmenistan – and a number of LNG suppliers are courting the Turkish market.

Future Exports to Europe and Asia

Table 5.17 shows the gas export projections of Gazprom compared with those in the Russian Energy Strategy for 2000-2020. Exports to CIS and Baltic Countries will remain roughly constant throughout the period. Exports to Europe will increase strongly from 2000 to 2005, but more gradually over the next 15 years. Gazprom anticipates only a 20 Bcm increase in exports to Europe after 2005, less than the full capacity of a single large-diameter pipeline. The Russian Energy Strategy projections are only marginally higher. Whether the low growth projection for European exports after 2005 reflects judgements about market opportunity or return on investment, the clear message is that the task of winning European market share will be almost completed by 2005. Additional export ambitions will depend on the development of gas demand and pricing in Europe as liberalised markets unfold across the Continent. It is of course possible that alternative exporters of Russian gas to Europe will come forward with projects independent of Gazprom.

Table 5.17 Russian Gas Export Projections 2000-2020 (Pessimistic–Optimistic), (Bcm)

	2000	2005	2010	2015	2020
Exports outside CIS & Baltics*					
• Gazprom**	130	180	190	195	200
• Energy strategy	137	175-190	195-205	200-210	200-210
Exports to CIS*	71	65-75	63-82	59-82	55-82
Total exports*	208	240-265	258-308	259-292	255-292
Total exports***	**217**	**245-260**	**245-275**	**260-280**	**275-270**

** Draft Main Provisions (March 2000) / **Gazprom / *** Main Provisions November 2000.*

Gazprom's current focus is on arranging adequate pipeline diversification away from the Ukraine. On the commercial side, there is little confidence that satisfactory and lasting arrangements can be concluded with Ukraine. On the logistical side, there is concern that, without substantial additional investment in refurbishment, the capacity of the Ukrainian pipelines could fall steeply from the current 135 Bcm/year. Efforts by Gazprom, foreign companies and the Ukrainian government to reach agreement on the future status and management of the Ukrainian transit system have so far proved fruitless.[92]

►►► ***Commercial companies should be encouraged to invest in Joint Implementation projects*** *for pipeline and compressor-station refurbishment in Russia and for transit pipelines*

91. In fact the offshore section of Blue Stream will consist of two pipelines taking slightly different seabed routes but with the same landfalls.
92. Ukrainian sources suggest that transit capacity is much larger – up to 160 Bcm/year. A number of different options has been suggested, such as privatization of the network with investors taking strategic stakes, and long-term concessions.

carrying Russian gas through Ukraine. These would be attractive commercially and would have a beneficial impact on efficiency and emission reductions.

Gazprom's understandable frustration over its transit problems in Ukraine has resulted in decisions to build the alternative pipeline routes described above. Yet these plans will leave idle pipeline capacity in the Ukrainian and Russian systems. It will be extremely expensive and it will also fail to provide any long-term solution to transit problems. A more comprehensive approach to transit problems is offered in the Energy Charter Treaty and its Transit Protocol. Ratification by Russia would send positive signals to entice other transit countries into more predictable and transparent transit business practices. This would help avoid the construction of expensive bypass pipelines, such as the one planned to by-pass Ukraine. Ratification would provide a common legal basis for gas in transit from and through CIS countries, including the Central Asian states. It would provide all parties with an international legal foundation, including international dispute settlement.

►►► ***The Russian government and Gazprom should urge the Duma to ratify the Energy Charter Treaty as soon as possible.*** *During the negotiations of the Energy Charter Transit Protocol, Russia should encourage the establishment of a reliable international energy-transit regime, sign the Transit Protocol and ratify it. The certainty growing out of an international transit regime could provide a basis for refurbishment of pipeline infrastructure. It would reassure importing countries that security of supply would be maintained and transit interruptions avoided.*

EU-Russia Energy Partnership

The Russia-EU Summit held in Paris in October 2000 produced a new energy dialogue. The dialogue is to be an exchange between equals, setting out the common interests of the EU and Russia in the energy sectors. It recognises the complementarity of the partners' respective energy markets and seeks to identify the potential for co-operation in the energy field.[93] The exploratory phase of the dialogue has set up four groups to study the following issues:

- energy strategies and balances;
- investments;
- infrastructure and technology;
- energy efficiency and environment.

The EU Green Paper on security of supply says:[94]

"The European Union must establish an ongoing dialogue with producer countries… [T]he dialogue should be extended to all matters of common interest, in particular protection of the environment and technology transfer… Russia said it was prepared to work towards improving the Union's long-term security of energy supply and… concerning prices and quantities, to put the emphasis on balance. For its part, the European Union is prepared to mobilise European technical assistance to facilitate European investments in transport and production in the energy sector. These measures should be finalised within the framework of a co-operation and partnership agreement between the European Union and Russia."

93. *EU-Russia Energy Dialogue: an overview*, IP/01/701 Brussels, 1 June 2001.
94. EU (2000), *Towards a European Strategy for the Security of Energy Supply*, Green Paper, COM (2000) 769, Brussels, 29 November, p.87.

At the Russia-EU summit in October 2001 a political decision was taken to establish a strategic Energy Partnership. This is to be a two-to-three year negotiating phase intended to reach an Energy Partnership agreement between the parties. The negotiations will focus on 5 themes of mutual interest:[95]

- ensuring the security of energy supplies of the European continent;
- the development of the vast potential of the Russian economy, in particular Russia's energy resources;
- the opportunities of the pan-European energy market;
- the challenge of climate change;
- conditions framing the use of nuclear energy.

Asian Markets

Another set of markets awaits Russian gas in Asia. Over the past decade projects have been proposed to export gas from Eastern Siberia and the Russian Far East to Japan, China and Korea. The projects currently under consideration are:

- LNG and/or pipeline exports of gas from fields discovered offshore Sakhalin Island. The Sakhalin 1 and Sakhalin 2 PSAs, have substantial gas reserves adequate to support LNG or pipeline projects to Japan, China and perhaps also Korea. Much remains to be decided in terms of:
  - whether the gas will be moved by pipeline or as LNG;
  - whether each projects will build its own infrastructure or share joint facilities;
  - where are the markets and buyers for the gas.
- the Kovykta gas field in the Irkutsk oblast, where partners in RUSIA Petroleum are in the preliminary stages of negotiations with buyers. Development would require a major pipeline to be built from the field to central China, with a possible extension to Korea.

These projects involve multinational energy companies; in Sakhalin they are the majority shareholders.

In addition, major gas fields have been discovered in the Sakha Republic, adequate for exports to Japan or China, either separate from or integrated with the Kovykta (Irkutsk) project. Given the distance of these reserves from export markets, early development seems unlikely. It would probably need to tie in with the Kovykta export infrastructure. In April 1999, Gazprom formed VostokGazprom, a new company to deal solely with development and export of gas in eastern Siberia and the Far East, and to study proposed export projects to China based on west Siberian gas.

No one knows when Russian exports to Asian countries might commence. The production projections of the Energy Strategy (Table 5.2), foresee that exports from Kovykta will start by 2010, while Sakhalin gas exports would either be under way by then or start shortly thereafter. The Energy Strategy suggests that exports of gas from the Sakha Republic could start as early as 2010, but they are by no means a certainty

95. EU-Russia Energy Dialogue, *Synthesis Report*, October 2001.

even in 2020. The year 2010 seems a highly optimistic target for the commencement of any export project other than Sakhalin LNG and pipeline supplies.

THE FUTURE OF GAZPROM

Management, Corporate Culture, Governance and Transparency

The year 2001 was a watershed year for the Gazprom management, with the retirement of its long-time executive chairman, Rem Vyakhirev in June 2001 and his subsequent elevation to chairman of the supervisory board. His replacement as CEO, Alexei Miller, was a deputy energy minister and a long time associate of President Vladimir Putin. A number of long time executive board members have been replaced. Together with expected retirements on age grounds, this could produce a sharp change in management and corporate culture. Gazprom's approach had already changed during the 1990s, with much greater emphasis on profitability and market developments, and made less emphasis on resource and infrastructure issues.

The extent to which the new management is committed to transparent business practices will be a major determinant of the company's future. Quite aside from a culture of confidentiality, which it shares with many gas companies throughout the world, Gazprom's lack of transparency in the 1990s was exacerbated by the payments problem. Gazprom has frequently extended loans to certain companies and delivered gas in exchange for non-cash receivables. This in turn has:

- prevented any straightforward denomination of prices, or comparison of costs with receipts;
- prevented any easy calculation of the company's tax burden; gas deliveries and mutual "offsets" were common methods of tax settlement during the 1990s;
- brought Gazprom total or partial ownership of many different businesses, including some that are very far-removed from its core business, such as a major media group. The financial basis of these loans has frequently been unclear, especially when they involved the exchange of gas for equity in these businesses.

Since 1995, Gazprom has been active on international financial markets due to its increasing need to raise money by international borrowing and the sale of equity. This has obliged the company to provide much more information about itself, both to the international financial community and more widely, than it had ever done before. Publication of annual accounts prepared to international accounting standards was another aspect of this culture change. The traditional corporate secrecy of the Soviet era began to dissolve even before the company's website was set up.[96]

Nevertheless, transparency and good governance are still problems. During 2000-2001, attention has focussed particularly on the lack of transparency in the company's relationships with other firms in the Russian gas sector, notably Itera and Stroitransgas. This opacity has led to widespread allegations of improper relationships between

96. www.gazprom.ru

Gazprom management and the management of other companies. Similar charges are laid against the gas export and marketing entities in the Russian "near-abroad".

One of the primary sources of pressure for more openness has been a group of independent shareholders which has a representative on Gazprom's Board. This group's principal concern is that activities of management may be adversely affecting the company's share price. Another aim of the group is to abolish the "ring fence" between the company's domestic shares, which trade at a substantial discount, and its international shares.

In early 2001, investigations began into Gazprom's financial practices and commercial and ownership relations with other companies. Although these investigations failed to discover any improprieties, which were sufficiently serious to warrant legal action, far tighter rules of corporate procedure and transparency are certain to be introduced.

Relationships with Government

Relationships between Gazprom and the government have been extremely close, to the point where it was often hard to distinguish government policy from company policy. As the largest shareholder in Gazprom, and with a majority of members on the company's supervisory board, the Federal Government clearly had the major role in deciding how quickly existing management should be replaced and in choosing the individuals who will constitute the new management. These choices will determine the speed and direction of change over the next five years. Selection of a large number of "outsiders" for key management positions would indicate that government is seeking rapid restructuring and liberalisation of the industry. Indeed, with its voting power on the supervisory board and with CEO Alexei Miller a close associate of President Putin, the government has placed itself in full control of – and therefore given itself full responsibility for – the gas industry's future.

The sheer size of Gazprom relative to the Russian economy – 20% of federal budget revenues, 20% of foreign exchange earnings and up to 8% of GDP[97] – means that its business decisions must command the attention of government. Strong government involvement is virtually inevitable. Much of what has gone wrong with domestic gas pricing and payments stems directly from government's inability to implement price reform as a component of general economic reform during the 1990s. Government concern about the unemployment and social dislocation that was bound to follow large-scale closures of companies has been a major factor in the continued tolerance of low gas prices, non-payment and non-cash payment. At the same time, with government desperate for additional budget revenues, Gazprom has become a large and easy tax target. Low prices and widespread non-payment, combined with very high taxes explain Gazprom's reduced incentive to deliver gas to domestic markets or to invest in new gas supply for these markets.

The government has always been involved at the highest levels in the export of Russian gas, and in the transit of Central Asian gas to CIS countries. Negotiations on volumes, prices, payment conditions and debt settlements are ultimately confirmed by the prime

97. These figures are estimates for 2000. Gazprom has been variously estimated to account for 4%-8% of Russian GDP.

ministers or presidents of CIS countries, after agreement with their Russian counterparts. The strategic interests of the Russian government are directly engaged in ensuring that Russia remains a supplier of gas and oil to CIS countries and provides transit of fuels between those countries. The EU-Russia Energy Partnership will provide still another opportunity for direct government involvement.

Restructuring, Liberalisation and Competition

The government now has a real opportunity to influence the development of the gas industry through restructuring, liberalisation and competition. Throughout the 1990s, there were calls – both from Russian reformers and from international financial organisations – for the "break-up" of Gazprom into separate production and transmission companies. From 1995 to 2000, internal restructuring of Gazprom took place but this has not changed the essentially vertical structure of the company.

Critics point out that in 2000 Gazprom produced about 90% of Russian gas, transported all gas in high-pressure pipelines from Siberia westwards and held all the export contracts for gas sold outside the CIS and Baltic countries. Gazprom's move into low-pressure distribution and sales over the past five years can be seen as a further step in the direction of vertical integration and away from competition.

On the other hand, progress *has* been made over the past five years towards creating a structure with the potential to develop gas-to-gas competition. In accordance with a 1997 presidential decree[98], a major restructuring has converted Gazprom's daughter companies into wholly-owned limited companies. At the same time, another such company – Mezhregiongaz – was created to handle all Gazprom's sales. The idea is that the subsidiaries should operate a system of internal transfer prices. Mezhregiongaz pays the production companies for gas and transportation companies for their services. The transportation subsidiaries, however, are not required to charge the regulated transportation tariffs set by the Federal Energy Commission. If transportation charges for the transmission subsidiaries were set at the regulated tariff, if the production subsidiaries were paid a cost-related price for their gas and if both sets of companies were paid in full, promptly and in cash – then prices to Russian customers would rise sharply. It is the system of subsidised prices to Russian gas customers principally that maintains Gazprom's dominant position. Implementation of the price increases advocated in the Energy Strategy (see Table 5.13 above) would remove the basis for this dominance.

Non-discriminatory transmission tariffs applied to all users of the pipeline network, including Gazprom subsidiaries, would strongly promote the development of a competitive gas market – something that could not have taken place in the price and tax environment of the late 1990s. If prices now approach cost-based levels and then move to parity with European export prices, the Russian market will become profitable to serve, and competitors will have incentives to enter the market.

►►► ***Transparent pricing*** *between* Gazprom *subsidiary companies should become wholly transparent, specifically gas purchase prices and transportation charges.*

98. Presidential Decree No. 426, 28 April 1997.

The 1997 reforms have been extended and reinforced by the Putin administration. The Ministry of Economy and Trade's Economic Development Strategy declares that "institutional changes in the fuel and power sectors must be accompanied by total organisational and financial transparency."[99] In the section on the gas industry, the Economic Strategy speaks of:

- identifying and establishing economic entities to demarcate the natural-monopoly and competitive spheres of gas activities;
- creating separate structural units within the framework of existing organisations in the gas sector and spinning off these units into independent commercial companies.

It cites the creation of production, transmission and sales companies within Gazprom as an example of this process and suggests that similar steps be taken in gas distribution companies to separate natural monopoly functions such as pipeline ownership from sales and other activities.[100]

►►► ***Clarification of the relationship between Gazprom and independent producers and others is critical.*** *The appearance of independent producers like Itera – a large independent producer and user of the pipeline network – is to be welcomed, subject to a full clarification of the relationship between that company and Gazprom. The relationship between Gazprom and Sibur requires similar clarification. In the case of Sibur, substantial ownership or take-over by Gazprom is highly undesirable and anti-competitive; it could prevent full use of associated gas production. This problem can be addressed only partially through regulation.*

The Strategy fully recognises the importance of price and regulatory reform, in particular:[101]

- "introducing non-discriminatory rates for gas transport via trunk gas pipelines and local gas distribution pipelines (and subsequently for other additional services), and improving mechanisms for obtaining access to these gas pipelines;
- "redefining the amount of available capacity in the gas transport system…[and] including in Gazprom's obligations a provision to the effect that it will regularly furnish independent gas suppliers with information on amounts of available capacity…"
- "setting limits on the amount of natural gas the Mezhregiongaz may purchase from Gazprom [production] enterprises, with a view to enabling gas distribution and independent gas marketing organisations to make direct purchases from such enterprises; co-ordinating with Gazprom a program to reduce direct purchases by Mezhregiongaz for a period of five to ten years."

►►► ***Market-share targets may be the most workable solution to help new companies to compete.*** *Even with aggressive price reform and favourable access terms, the position of Gazprom in the Russian gas market is so strong that it will be extremely difficult for new companies to compete. Market-share targets are a system in which the government and/or the regulatory authority requires the dominant company to reduce its market share – in the whole market or in defined sectors of it – to a certain percentage by a certain date.*

99. *Strategy of Development of the Russian Federation through 2010, Social and Economic Aspect*, Centre for Strategic Research, submitted to the Government of the Russian Federation on 25 May 2000, Section 3.5.1.
100. *Ibid.*
101. *Ibid.*

The Development Strategy explicitly advocates liberalisation of the sector. It also suggests that purchase limitations be set for Gazprom's marketing subsidiary Mezhregiongaz for purchases from Gazprom production subsidiaries. This could translate into a market-share target limiting how much of the market may be supplied by Mezhregiongaz. The creation of a "gas exchange" is envisaged in order to develop gas trading. The role of the regulatory authority will be to phase out price regulation progressively and concentrate on regulation of transportation tariffs in order to develop competition further. At the same time, there is a recognition that all of these aims will depend on price and market reform.[102]

Gazprom has no legal export monopoly, but enjoyed a *de facto* monopoly up to the mid 1990s. As far as exports to CIS countries are concerned, this was broken with Itera becoming a major supplier and shipper of gas to those markets. But Gazexport's *de facto* monopoly of exports to Europe remains intact. There is considerable opposition to any change in this situation within both Gazprom and the Russian government. No benefits are seen from allowing other companies to compete in the European gas market. This is understandable, given the huge incentive provided by the pricing structures of the 1990s to deliver gas to European rather than to Russian and CIS markets. The reliance of Gazprom and the Russian government on revenues from European exports has become so great that any measures that could jeopardise these earnings will be rejected. Yet developments in both the Russian and European markets require a rethinking of this position. Price reform in Russia should make the domestic market much more profitable to serve, while increased competition in Europe may threaten the market share of Russian gas and require more diverse export initiatives from a wider range of Russian companies.

The FEC should confirm that players other than Gazprom have the right to export gas to Europe. In particular, it should investigate whether the much-repeated claim that insufficient transportation capacity exists to allow other companies to export to Europe is, in fact, correct. In practice, irrespective of the existence of transmission capacity, until price and payment reforms make sales to the Russian market more attractive, the government must decide whether new players (including associated-gas producers) should be allowed to develop gas solely for export to Europe, or whether exports should be made only after the Russian and CIS markets are served. If the government decides to retain Gazprom's monopoly of exports to Europe, this should be on a transitional basis, and a date should be set no later than 2005 for others to be allowed to compete in European markets

►►► ***The present*** **Gazprom/*****Gazexport de facto monopoly on exports to Europe needs to be reviewed.*** *This is especially important in light of developments in transmission charges and access rules within Russia. As the European gas market becomes more competitive, with short-term trading and transparent pricing, there will be increasing opportunities for sellers of Russian gas in European markets. But there may be serious barriers to entry for potential exporters. The terms on which future exporters can gain access to capacity in the Ukrainian and other transit pipelines will be an important issue.*

102. *Ibid.*

While the Development Strategy and the Energy Strategy are mutually reinforcing, the time frame in which restructuring and liberalisation of the industry will be introduced remains uncertain. An interview with a senior official from the FEC in early 2001 confirmed that top priorities are the creation of stand-alone businesses for production, transportation and trading; non-discriminatory access to pipelines; and reform of the tax system to create incentives for new players.[103] Yet in a key passage the official noted:

"We should be realistic and realise that there will not be a competitive gas market in this country in the immediate future…What we say is that new players must come to the gas market, and we must create adequate conditions for that. And if there are new players let them play using civilised rules. Today such rules are not in place. We do not guarantee, however, that there will be any new players. What we say is that appropriate conditions should be created….But we honestly say that Gazprom is huge and it will be very difficult to make our players really competitive."

As this chapter was being completed in July 2001, Prime Minister Mikhail Kasyanov signed an as yet unpublished programme for social and economic development, which foresees the division of Gazprom into a pipeline network company and a number of production companies by 2004. Many issues remain to be resolved in such a programme, in particular the treatment of existing shareholders and the title to long-term export contracts with European gas companies. Before any such restructuring can take place, Gazprom will need to reduce its external debt and eliminate the "ring fence" between the trading of domestic and foreign shares in the company. This will require at least three years. The government strategy on competition and restructuring therefore appears to be to bring new players into the gas industry as quickly as possible and then to restructure Gazprom. This will require several years to complete and the speed of change will depend strongly on general economic reform, especially price reform.

►►► ***The Russian government has clarified the main elements of its future strategy for restructuring and introducing competition into the gas industry.*** *What is now needed is a detailed timetable for restructuring of the company, which would assist the government, shareholders and customers in planning of future reforms and commercial relationships. Such a timetable should show how restructuring of the industry will be coordinated with the introduction of legislation and price reform in order to give confidence to investors and to provide benchmarks against which to measure its progress over the next five years.*

103. Interview with Vladimir Milov, Section Head, Economic analysis and regulation systems development, Kommersant Daily, 16 January 2001.

6. COAL SECTOR

EXECUTIVE SUMMARY

Coal Supply and Demand Structure

Russia is the world's sixth-largest producer of hard coal, after China, the United States, India, Australia and South Africa. It accounts for about 5% of world production. It is the world's eighth-largest hard-coal exporter. From 1990 to 1999, coal held a relatively constant share of Russian TPES, from 21% to 18%, respectively, despite a drop of almost 50% in hard and brown coal production, from a peak of 425 Mt in 1988 to 235 Mt[104] in 1999. The drop resulted mainly from a sharp decline in domestic demand, accompanied by growing inefficiency in the coal-mining industry and a lack of investment in maintenance, technology and the opening of new mines. In contrast, to earlier years, coal production increased 8% in 1999. According to Russian statistics, gross (unwashed) coal production increased another 3% in 2000 to 258 Mt. The main domestic market for coal is the electricity sector, which increased its share in total coal use from 48% in 1990 to 60% in 1999. Metallurgy and other transformation industries maintained their share at about 10%, while exports dipped from 16% in 1990 to 10% in 1994 and back up to 14% in 1999.

Restructuring of the Coal Sector

The coal industry has undergone a major restructuring since 1993, in two phases. The first saw large-scale closure of uneconomic mines, resulting in an increase in the sector's competitiveness and labour productivity. The second, from which the sector still struggles to emerge, centers on improving productive fields and opening new ones. The success of this process is critical for the sector to meet the rapidly growing domestic demand that current planning foresees. The coal industry also strives to compete in international coal markets and competes internationally to raise capital. It is hampered by social burdens and a lack of finance, worsened by the generally unstable investment climate in Russia.

Outlook and Limiting Factors

The *Main Provisions of Russia's Energy Strategy to 2020* are based on increasing coal use in the heat and power sector in order to lower dependence on gas in the fuel mix. The *Main Provisions* project the share of coal in the fuel balance to increase from about 20% in 2000 to 21-23% in 2020, with a matching decrease in the shares of natural gas and oil, to meet increasing electricity and heat demand and increase energy efficiency. To achieve this, coal production will need to rise by almost 75% by 2020, to 340-430 Mt/year. Despite the sector's progress toward restructuring during the 1990s, several factors raise concerns about its ability to meet this challenge. Question- marks attach to the sector's capacity to attract the needed investment, the competitiveness

104. Note that as of 2001, IEA coal production statistics for Russia have been revised to show "washed or marketable" coal (after removal of inert matter) as opposed to previously reported "unwashed" coal (commonly used in official Russian statistics).

of coal as an input fuel *versus* natural gas and the environmental implications of increased mining and use of coal.

Coal Exports and Export Markets

Total Russian hard and brown coal exports dropped significantly from 1990 to 1998, from 59 Mt to 26 Mt. IEA statistics show a 14% increase in 1999 to 29 Mt. Russian statistics show a 21% increase in 2000, to 35 Mt. Lower domestic prices and the sector's chronic payments problems make exporting seem extremely attractive. Both internal and external factors limit exports, however. They include the quality of Russian coal and the long distances of coal mines from export ports.

COAL SUPPLY AND DEMAND STRUCTURE

Coal Reserves and Production

In 2000, according to the Russian Coal Industry Committee, total coal resources were over 200 billion tonnes. The Russian government estimates its proven recoverable coal reserves at just over 157 billion tonnes[105]. This is broken down into hard coal including anthracite (49 billion tonnes), brown (97.5 billion tonnes) and lignite (10.5 billion tonnes). Proven reserves controlled by coal producers are much lower, between 14.6 to 17.1 billion tonnes,[106] of which only 11.3 billion tonnes meet international quality standards. These discovered reserves, even assuming a many-fold increase in demand, would last for hundreds of years. Map 8 shows commercial reserves across Russia, both total resources and those now considered economically recoverable.

Coal in Western Russia generally appears in relatively thin, deep seams that are increasingly costly to mine. Seams in Eastern Russia and Siberia are thicker and often lie under shallow overburden, making surface mining feasible, with generally larger mines and lower production costs. Reserves in Siberia, however, are often distant from major consumption areas and export markets. Russia's main coal basins are:

- Kuzbass Basin: (44% of 1999 production) The main coal-producing area of Russia, the basin contains more than 65% of Russia's total hard-coal reserves. This West Siberian region's deep and opencast mines produce hard coal, often from thick seams. Many of the coals have high quality, with low sulphur, inherent moisture and ash content. Apart from Novosibirsk, its main consumption centres (in the Urals and the Moscow regions) lie thousands of kilometres away, while the nearest export port is some 6,000 kilometres distant;
- Kansk-Achinsk (KATEK): (15% of 1999 production) Located several hundred kilometres east of the Kuzbass basin, this Central Siberian region's large reserves of brown coal come mainly from open-cast mines. This coal is more suitable for on-site consumption for power generation;[107]
- East Siberia and the Far East: (Almost 14% and 12% of 1999 production, respectively) These areas produce both hard and brown coals;

105. Submission by the Russian government to the World Energy Council *1999 Survey of Energy Resources*.
106. Coal Industry Committee, *The Russian Coal Industry: Current Situation and Outlook*, Moscow, 2000
107. Brown coals like those found in the Kansk-Achinsk coal regions are most economically used in mine-mouth power generation and for nearby facilities where transportation costs are a minor factor. If the mine-mouth power option is adopted, however, the transmission grid must be overhauled.

- Pechora Basin: (8% of 1999 production) Mostly above the Arctic Circle, this region's deep mines produce both steam and coking coal;
- Donbass Basin: (4% of 1999 production) The Donbass was formerly the centre of coal mining in the Soviet Union. This basin lies mainly in Ukraine with an eastern extension into Russia. Its deep mines produce anthracite and hard coal.

Coal production in Russia peaked in 1988, at 425 Mt. Over the next decade, it dropped about 45%, to 235 Mt in 1999. Russian statistics show gross (unwashed) coal production increasing in 2000, to 258 Mt. In the 1990s, production concentrated in the more central and profitable reserves. Table 6.1 shows an increase in the share of production from the Kuzbass basin and a decrease in shares of some other basins. The outlook to 2020 projects that large enterprises with capacities of over 0.5 Mt will provide about 80% of coal production, while smaller coal ventures will see their share in production increase from 4% in 2000 to 15%-20% in 2020.

Table 6.1 Russian Coal Production* by Region

	1990	1993	2000
Russia (Mt)	**395**	**306**	**258**
Regional shares (%):			
Kuzbass Basin	35.4	35.0	44.6
Kansk-Achinsk Basin	13.9	14.2	15.7
East Siberia Region	13.4	16.7	14.2
Far East Region	9.1	9.8	11.1
Pechora Basin	7.3	8.0	7.2
Urals Region	5.6	3.9	2.7
Donetsk Basin	8.1	7.0	3.8
Moscow-Tula Region	3.5	2.9	0.3
Others	3.5	2.6	0.4

** Russian statistics showing gross "unwashed" coal production.*
Source: RosInformUgol, 2001.

A shift to surface mining using the most efficient methods has borne fruit. When coal output peaked in 1988, surface mining accounted for 54% of it (Table 6.2). In 1980, underground mining accounted for almost the same percentage, 53%. From 1992 to 1998, surface mining further increased its share, from 56% to 62%, due partly to the opening of new open-cast mines and partly to closures of uneconomic and unsafe underground mines. In 2000, the estimated share of open pit-mines reached 65%. This trend is projected to continue, to 80%-85% by 2020.

Table 6.2 Coal Production* by Type

	1988	1993	2000	1988	1993	2000
	Million Tonnes			% of Total Production		
Type of mining						
Output from opencast mining	228	173	167	54%	56%	65%
Output from underground mining	197	133	91	46%	44%	35%
Type of coal produced						
Hard coal	274	193	172	64%	63%	67%
• *Coking coal*	*100*	*62*	*61*	*37%*	*32%*	*35%*
• *Steam coal*	*174*	*131*	*111*	*63%*	*68%*	*65%*
Brown coal	152	113	86	36%	37%	33%

** Russian statistics showing gross "unwashed" coal production.*
Source: RosInformUgol, 2001.

The share of hard coal production has remained stable at about two-thirds of the total, as has the breakdown between coking and steam coal. Steam coal accounts for about two-thirds of hard-coal use. This mirrors demand in the electricity sector, which is the major Russian market for hard coal.

Most Russian coal-preparation plants were built in the 1960s with parts manufactured in Ukraine or Kazakhstan. This has made it difficult to obtain spare parts or new equipment to replace what is now mostly depreciated and outdated capital stock. In 1999, only 41 of the 71 coal-washing plants working in 1992 remained in operation, with output down to 80 Mt from 163 Mt in 1992 and 98 Mt in 1995. The mine closures in the 1990s left many coal-preparation plants working under capacity, while mines unequipped with such plants were obliged to supply unprepared product, thus increasing the volume of coal transported by the railways. This highlights one of the sector's key needs: to put in place efficient methods for processing, particularly of coals with high sulphur and ash content (average ash content in 2000 was 20% compared with world standards of 7%-8% for coking coal and 10%-15% for steam coal). The target for steam coal is an ash content of 12%-15%. In an effort to increase the competitiveness of coal, the *Main Provisions* envisage wide-scale application of the most up-to-date methods of coal preparation and enrichment with the aim of meeting international quality standards (ISO 9000).

►►► ***Investment in preparation plants is very important*** *for Russian coal to meet environmental and market standards. Since the mine closures of the 1990s, new plants are also are needed.*

Coal Demand Structure

According to Russian statistics, in 1988, coal production peaked at 425 Mt. With coal imports more or less matching exports then, apparent domestic demand was above 400 Mt. IEA statistics show demand decreased by 40% from 1990 to 1998, from 374 Mt to 217 Mt, due mainly to the economic downturn. Other limiting factors included a lack of investment in new mines, mine closures and related social problems. In this period, the share of gas in TPES increased. The coal and nuclear sectors were expected to prepare themselves during this so-called "gas pause" for greater resource contributions after 2010. Over the period, the share of coal in TPES fell slightly from 21% to 18%, while that of natural gas rose from 42% in 1990 to 52% in 1999.

Stimulated by the economic turnaround in 1999, coal demand increased 4% to 226 Mt. Table 6.3 illustrates the structure of coal demand. The electricity sector is the main market for coal, accounting for 60% of total coal use in 1999, up from 48% in 1990. The metallurgical sector and other transformation industries maintained their share in total coal use from 10% to 11%, while exports decreased from 16% to 10% of the total in 1994, increasing to 14% in 1999.

In 2000, GDP grew 8.3% and industrial output by 9%. Industrial growth did stimulate demand for coking-coal for the metallurgical industries, which increased by over 16% in 1999 and by Russian estimates by another 7% in 2000. Although the electricity sector is the main domestic market, its demand for steam coal barely increased, despite increases in electricity supply of 2% in 1999 and 4% in 2000. Coal prices rose sharply in 2000 due to higher transportation charges as the rail carrier took advantage of strong

Table 6.3 Coal Balance of the Russian Federation, 1990-1999 (in Million Tonnes of Coal Equivalent)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Coal production	**257**	**222**	**206**	**193**	**176**	**167**	**160**	**152**	**145**	**165**
Imports	48	37	29	23	22	18	16	16	17	13
Exports	50	31	31	22	20	22	21	20	21	25
Stock changes	6	– 15	– 15	– 3	1	4	15	4	2	3
TPES	**260**	**213**	**189**	**191**	**179**	**167**	**170**	**152**	**144**	**156**
Statistical difference	8	22	6	4	– 2	13	8	1	6	4
Heat & power	150	135	123	125	121	116	121	108	104	109
Coal transformation	21	16	16	15	12	15	15	12	14	15
Own use / losses	19	15	13	12	10	9	9	7	6	7
TFC	**78**	**69**	**42**	**43**	**34**	**40**	**32**	**26**	**25**	**28**
Industry	22	20	19	19	17	24	21	15	15	15
– Iron and steel	17	16	15	14	13	19	17	13	12	12
Agriculture	1	1	1	1	1	0	0	0	0	0
Services	29	29	8	1	1	1	1	1	1	1
Residential	17	15	14	13	12	11	10	10	9	11
Other	10	5	2	10	3	3	0	0	0	0

Note: 1 tce equals 7 Gcal or $29.3x10^{-3}$ TJ.
Other includes: transport sector, non specified and non-energy use.
Source: IEA estimates for 1990-1991, IEA statistics 1992-1999.

market conditions to pass on costs. Deliveries to electric power stations during the first half of 2000 were higher than 1999, but were lower by an almost equal amount during the second half. At the end of 2000, coal stocks at power plants were 5% below 1999. By January 2001 they had dropped to less than 23% of 1999. With increasing electricity demand and lower supplies of natural gas, low coal stocks are a serious concern. Stocks did vary across electricity systems in Russia – normal in the Central and Moscow regions but insufficient to ensure energy security in the Far East, which suffered electricity and heat shortages.

Total Russian hard and brown coal exports plummeted in 1990 to 1998, from 59 Mt to 26 Mt. In 1999, exports increased 14% to reach 29 Mt. Russian statistics show them increasing in 2000 to 35 Mt, up 21% from 1999. This occurred despite low coal stocks at domestic power plants in 2000 and early 2001. Because of low domestic prices to producers and widespread non-payments of bills, the export market was a very attractive option for coal producers.

The coal sector faces a major disadvantage in the location of its mines far from centres of population, industry and exports. Each of the 89 Russian regions consumes coal, but only 24 produce it. This fact generates a lot of inter-regional coal transport, mainly from Western and Eastern Siberia, which send 30% and 20% of their production to other regions. Production has become more concentrated. Western Siberia accounts for 39% and Eastern Siberia for 30%. At the beginning of 2000, the European part of Russia, with the largest share of electricity consumption, held only 19% of total coal mining capacity. The Far East, which frequently has power shortages, holds only 12%.

RESTRUCTURING OF THE COAL SECTOR

Under the Soviet system, the Ministry of the Coal Industry of the USSR controlled regional production associations. It was succeeded in 1991 by the Ministry of Fuel and Energy (Ministry of Energy since 2000) and *RosUgol*, the state-owned coal company. The restructuring process created 14 regional coal production companies and 11 regional coal associations to act as regional holding companies, in addition to a few stand-alone private mines.

Over three years starting in mid-1993, the Ministry and *RosUgol* planned a major restructuring of the coal sector, beginning with freeing coal prices and a reduction in state subsidies. Mines were to become self-sufficient through increases in productivity as well as from higher prices for coal they produced. *RosUgol* could then sell mines to private investors and mine employees. Initially, the restructuring programme proved difficult and painful to implement. Lack of financial resources made it impossible to pay adequate support to redundant miners or to bring necessary materials and new equipment. Nor was capital available to open efficient new mines that would ensure the energy-security needs of the country.

In 1994, in an effort to reduce the burden of loss-making mines on the handful of profitable ones, *RosUgol* issued an order to close 46 mines. The number was later increased to 60. By December 1997, *RosUgol* comprised 27 production companies, associations and stand-alone mines established through subsequent reorganisations, mine mergers and mine closures. *RosUgol* was disbanded at this time, however, under an agreement between the Russian Government and the World Bank. At the beginning of 1999, the government established the Committee for the Coal Industry under the Ministry of Energy, responsible for state management of the coal sector.

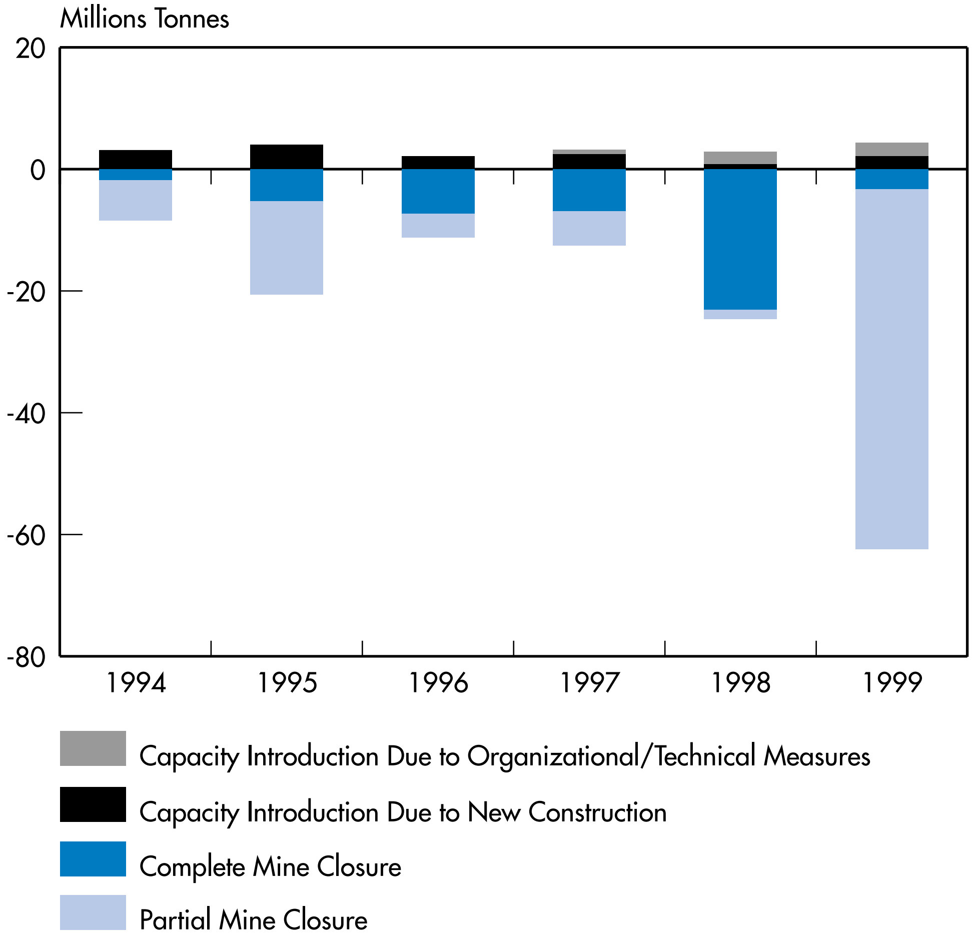
By 2000, 140 mines had been liquidated. As Figure 9 shows, most of the mine closures and reductions in inefficient capacity occurred in 1998-1999. In 1999 alone, 90 companies accounting for about 62.4 Mt of capacity were closed. That left some 220 coal-producing companies with 106 open-pit and 114 underground mines. Table 6.4 shows the breakdown of uneconomic mines as a percentage of totals by region, as well as progress to date in closing mines. By the beginning of 2000, 87% of all loss-making coal mines in Russia had been liquidated or were in the process of liquidation. Plans call for closing 25 more by 2003.

►►► ***Completion of the restructuring of the coal sector should occur as quickly as possible*** *in order to reduce subsidies, enhance the sector's competitiveness and increase the focus on investment in profitable mines.*

Average labour productivity in coal mining increased from 820 tonnes per miner per year in 1995 to 1,325 tonnes in 2000 (Table 6.5).[108] It ranges from a high of 5,320 tonnes

108. This compares to average labour productivity levels of other major coal producing countries (Australia, Canada, Colombia, Germany, Poland, South Africa, UK and US) of 3,980 tonnes per miner year in 1999. The performance at the national level ranges from a high of 12,100 tonnes per miner year in Australia to a low of 590 tonnes per miner year in Germany.

Figure 9 Liquidation and Introduction of Coal Mining Capacity



Source: RosInformUgol, 2000.

Table 6.4 Liquidation of Russian Coal Companies by Region as of 2000

Region/ Basin	**Number of Companies**						
	in 2000	**Uneconomic (Loss-making)**		**Low-profitability (Marginal)**		**Being Liquidated in 2000**	
		Total	**% of Total**	**Total**	**% of Total**	**Total**	**% of Total**
Total	**377***	**161**	**42**	**45**	**12**	**140***	**87**
Pechora	19	8	42	2	11	8	100
Moscow	29	22	76	5	23	19	86
Donbass	47	27	57	8	17	26	96
Kuzbass	105	38	36	14	14	34	90
Kiselovsky	15	15	100	13	87		
Sakhalin	18	11	61	11	100		
Primorsky	36	18	50	16	89		
Other	41	2	5	2	4	1	50

Source: RosInformUgol, 2000.

at KrasnoyarskUgol to a low of 150 at RostovUgol. A number of new, profitable coal fields, such as the Yerunak field of the Kuznetsk basin in West Siberia, are in the development stage. According to Russian coal experts, both surface and underground mines with "high-technology" engineering are in initial stages of construction at fields with the most attractive geology. This new technology could lead to annual productivity of 6,000-9,600 tonnes per miner, double the highest current level, with production costs estimated not to exceed 8 US dollars per tonne. The investment needs for "green-field" mines, which will have annual capacities of 1.5-1.8 Mt, amount to some $75-120 million.[109]

Table 6.5 Average Labour Productivity, 1995 to 2000 (Tonnes per Miner per Year)

	1995	1996	1997	1998	1999	2000
Russia	**820**	**881**	**973**	**1,055**	**1,235**	**1,325**
• Underground mines	467	475	523	575	685	738
• Opencast mines	2,016	2,112	2,132	2,120	2,312	2,347
Donbass basin	354	322	340	328	340	384
Kuzbass basin	725	761	856	959	1,152	1,228
Pechora basin	847	900	932	904	1,004	1,002
Kansk-Achinsk basin	3,899	4,298	4,121	4,086	4,243	4,505
South-Yakutia basin	4,987	5,231	5,724	4,795	4,542	4,538

Source: RosInformUgol, 2001.

Industry Restructuring and Labour Problems

Although technological advances in certain mines have helped increase the productivity of the sector, the key driver in improving the sector's competitiveness has been the mass closure of uneconomic mines. Massive job losses accompanied the closures. From 1993 to 2000, the number of jobs plunged by over half a million, or almost 60%. About a third of those who lost their jobs moved to services and other non-fuel occupations within regional administrations. By 2000, the number of workers in the industry had fallen to 370,000. Some 330,000 worked in coal companies, and of these 280,000 worked directly in the production of coal.

One-industry towns were hit hard by the closures. Miners had to be retrained. Many of them and their families were resettled. Social problems in mining regions increased radically in 1996. In 1998, the coal sector went through its most difficult period, with massive non-payment of bills and insufficient state funds to close loss-making mines and look after the redundant miners. A planned annual reduction in state subsidies of from 15% to 20% actually reached 40% to 50% in 1998 due to the general economic crisis. Unpaid salaries amounted to 3.53 billion roubles, five-and-a-half months' worth. Practically no funds went into the modernisation of equipment, reconstruction or opencast mines. Tensions peaked, and strikes exploded into mass protests. In May 1998, miners and other striking workers closed off parts of the North, North-Caucasus and West-Siberia railways, stranding passengers and freight. In response to the emergency, the Government increased financial support to the sector by one billion roubles. Beginning in 1999, with increased coal production and salaries being paid to the miners, the number of outbreaks reflecting social problems and tensions dropped from about 295 in 1998 to 79 in 1999 and many fewer in 2000.

109. Yu.N. Malyshev, President of the Russian Union of Coal Producers, *Coal Industry of Russia on the Eve and in the Early XXI Century*, paper presented at the XVIII World Mining Congress, Las Vegas, USA, 2000.

World Bank Support of the Restructuring Process

This painful restructuring process, which proved difficult even in highly developed countries, was exacerbated in Russia by the systemic political and financial crisis. The State lacked the resources to support mine closures, retraining and relocation of redundant miners and the welfare needs resulting from such a major sector overhaul. In 1996, the World Bank lent and disbursed $500 million to support coal sector restructuring in Russia. In calendar year 1996, the Government spent 10.4 trillion "old" rubles ($2 billion) of budgetary resources on support to the coal industry. In early 1997, First Deputy Prime Minister Anatoly Chubais ordered an audit of the use of the 1996 coal subsidies. The audit, carried out by the Ministry of Finance, concluded that about 3% (300 billion "old" rubles or $60 million) had either been disbursed to the wrong recipients or used for the wrong purposes. Partly as a result of these findings, the Russian government took a series of radical and far-reaching measures to improve the transparency of and accountability for subsidies being disbursed to the coal sector. The success of these measures has been indicated by independent audits.

Specific conditions calling for these improvements were included in the government's agreement with the World Bank to provide a second loan in support of coal sector restructuring in the amount of $800 million (Coal SECAL 2). The loan agreement was finalized in late 1997, and $400 million disbursed at that time. The government and the Bank agreed on a range of other conditions necessary for the release of the rest of the loan. After the government's failure in 1998 to meet these conditions, the loan was restructured, essentially preserving the original conditions but reorganising them in smaller tranches, more manageable for the government to fulfill. The remaining loan was divided into six tranches falling into three major areas (each of which have specific conditions associated with them): (i) closure of loss-making mines, including social welfare for laid-off workers; (ii) annual reduction and eventual elimination of subsidies to the sector; and (iii) privatisation of viable companies. *RosUgol* was dissolved, and its overall management functions transferred to the Ministry of Energy.

In 1999 and into 2000, $250 million were disbursed. As of mid-2001, $150 million remains to be provided by the World Bank if the government meets the remaining conditions for these funds. The funds still outstanding are split into two parts. A social tranche of $50 million covers reforms in the subsidy-management system, the mine-closure programme and related social issues. The final "privatisation" tranche of $100 million covers privatisation of coal companies and actions in such related areas as improvement of the regulatory and legislative framework governing the industry. The Japanese Bank for International Co-operation (JBIC) is providing co-financing in the same amount. JBIC has disbursed $650 million in matching funds, and will provide $150 million more if the government completes all remaining conditions and the World Bank disburses the remaining tranches (Table 6.6).

Subsidies

As part of the centrally planned Soviet economy, the Russian coal sector was charged with filling coal-supply needs for heat, electricity and heavy industry. Little attention was paid to economics and profitability. The state invested huge sums to establish the massive infrastructure necessary to mine various grades and brands of coal and to link remote mines to consumers. It set production targets centrally and the industry delivered coal to consumers accordingly, regardless of costs. The central budget balanced the

Table 6.6 Budget Finance to the Coal Sector and Adjustment Loans to Support Coal Sector Restructuring in Russia, ($ Million)

	1995	1996	1997	1998	1999	2000
State budget	1,625	1,940	1,120	540	410	200
World Bank	25	500		400	150	100
Japanese Bank for International Co-operation			400	0	150	100
Total	**1,650**	**2,440**	**1,520**	**940**	**710**	**400**

gains and losses from low- and high-cost mines, creating little incentive for efficiency. The operating budgets of coal mines covered pensions and other social payments of the miners and their families. As late as 1993, the state budget supported almost 80% of the sector's activities, which ranked second only to agriculture in its draw on the budget. In 1993, subsidies to the coal sector were about 1.05% of GDP. This dropped to 0.47% in 1996, 0.20% in 1998 and 0.12% in 2000.

In line with the Ministry's restructuring initiative, as well as the World Bank loan conditions, subsidies to the coal sector were systematically reduced after 1995 (Table 6.6) and were increasingly aimed at social welfare, rather than to subsidising loss-making mines. In recent years, the government has concentrated its subsidy financing in such so-called 'priority' categories as social welfare, disability payments, community development and safety measures. Consequently much less financing has gone to 'non-priority' categories including making up operating losses. In 1996 only a small proportion of subsidies (13%) paid for mine closures and almost half went to cover losses due to high production costs and arrears. By 2000, the breakdown in subsidies had completely changed (Figure 10). Over a third went to closing uneconomic mines, 28% paid for related welfare needs and only 10% covered mine losses. Further, the government has committed itself to eliminating operating loss subsidies by the end of 2001.

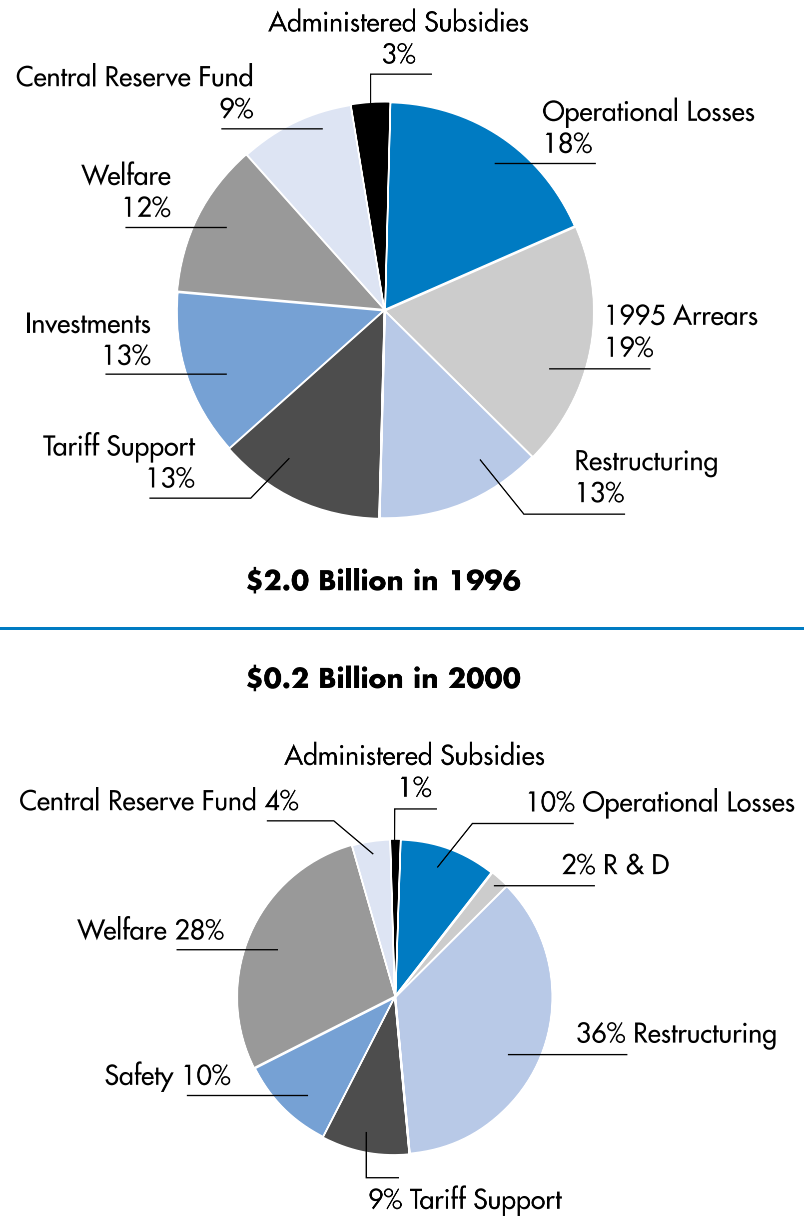
►►► ***Phasing out Subsidies to the Coal Industry.*** *The reallocation of subsidies away from supporting operational losses towards mine closures and associated welfare costs is commendable. Programmes to phase out subsidies to the industry should be given high priority. Any financial support for social programmes will be more efficient if provided directly to those most in need rather than via general subsidies.*

Coal Sector Privatisation

The Russian coal sector has gone through an extraordinary transformation of its ownership in just a few years. The government has stood solidly behind its policy of privatization of the coal industry, offering the best assets – the surface mines of Siberia – for sale first. The government has further shown its good will by revoking its golden shares[110] in two major companies (Kuzbassrazrezugol and Yuzhny Kuzbass) after the two-year period had elapsed following transfer of title. Problems exist balancing the local interests in gaining too much control in regional mines. This will need to be

110. A golden share is a minimum, indeed symbolic, state holding which allows the government a blocking majority of the board of directors in big issues.

Figure 10 Breakdown of Coal Subsidies



Source: Rosinformugol 2001 and IEA CIAB (1996), "Coal Prospects in Russia", Paris.

resolved to ensure that privatization takes root. But initial steps in the privatization process of the coal sector have been effectively taken. The ultimate target in the government's agreement with the Bank was to privatise companies accounting for 45% of 1996 production. By mid-2001, according to the Ministry of Energy, the government had privatised coal companies accounting for more than 60% of 2000 production. At the end of 2000, the coal sector comprised about 75 coal-producing joint-stock companies (not counting subsidiaries), in 22 of which the federal government still held shares (and a majority of the shares in six).

Table 6.7 Characteristics of Coal Companies in Russia in 2000

Company	2000 Production Mln Tonnes	Labour Productivity T/Month	Ownership (%)		
			Federal	Regional	Private
KrasnoyarskUgol	37.5	370	golden shares	18.4	81.6
KuzbassrarezUgol	34.6	178		14.8	85.3
KuzbassUgol	16.7	69	79.7		20.3
VostsibUgol	15.6	233	41.1	1.9	57
KuznetsUgol	15.2	93	80.6	14.4	5.0
ChitaUgol	11.0	353		14.1	85.9
Yuzhnyy Kuzbass	11.0	179		15.1	84.9
YakutUgol	9.0	303		100	
VorkutaUgol	9.0	70	39.9	20.0	40.2
ProkopievskUgol	7.1	44		25.1	74.9
Raspadskaya	6.3	136			100
LUTEK	6.2	228			100
GukovUgol	5.1	43	40.9	20.0	39.1
IntaUgol	4.7	112	60.5	24.9	14.6
ChelyabinskUgol	4.4	45	42.4	20.0	37.6
Mezhdureche	4.2	147			100
Chernigovets	3.9	122			100
RostovUgol	3.7	25	67.0	20.0	13.0
Vorgashorskaya	3.4	102			52.0
PrimorskUgol	3.4	91	38.0	20.0	42.0
Polosukhinskoe	3.1	192			100
Tulunsky	3.1	313	16.3		83.7
Sokolovskaya	3.0	161			100
VakhrushevUgol	2.3	86	38.0	22.5	39.5
DalvostUgol	2.1	115	40.3	20.0	39.7
OblkemerovoUgol	2.1	72			100
UrgalUgol	2.0	77	38.0	20.0	42.0
Chernogorsk ChernogorskayaUgol	2.0	116			100
KiselevskUgol	1.8	46	65.2	25.3	9.5
MezhdurechenskUgol	1.8	62	golden shares		100
Leningradslanets	1.7	71	40.6	20.0	39.4
KhakasUgol	1.6	76	43	14.4	42.6
Zapadnaya	1.3	76			100

Note: There were 40 more companies with production levels under 1000 tonnes in 2000, of which 17 were 100% privatised and four were over 51% privately held.

Source: Rosinformugol (2001), Rating Coal Producing Companies of Russia, January-December 2000.

The Russian Energy Strategy envisions privatisation of the remaining federal shares in coal companies by 2002. Some companies may be kept in state hands in regions where unprofitable mining maintains the energy security of the region – where, that is, using local coal is more economic than transporting other fuels to the region, as in the Far North. The Strategy also foresees the maintenance of federal "golden shares" in coal enterprises that are vital to Russia's energy security.

At the end of 2000 the Coal Committee had been liquidated in a government reorganisation aimed at reinstating the Ministry of Energy with a mandate to regulate and oversee the coal sector. Reflecting the increased importance of coal in the energy policy outlook and the economy of Russia, the Ministry of Energy established a department to deal with the coal industry, responsible to a Deputy Minister.

►►► ***Continuation of Privatisation.*** *A continuation of the privatisation effort is essential to attract financial resources and stimulate incentives for efficient production and processing of coal.*

OUTLOOK AND LIMITING FACTORS

Outlook for the Coal Sector

As discussed in Chapter 3, Russia's new energy outlook foresees a decrease in the share of natural gas in the energy fuel mix in favour of coal. The *Main Provisions* project an increase in annual coal production from about 260 Mt in 2000 to between 290 Mt and 335 Mt in 2010, increasing to between 340 Mt and 430 Mt in 2020. Increased production from the Kuznets basin will play the biggest role in reaching these goals, expected to supply 1/3 if production. . Output gains from the Kansk-Achinsk basin will lead in 2010-2020.

To reduce the risk to energy security if goals for increased gas and nuclear production are not met, emphasis falls increasingly on coal. Taking into account the retirement of depleted mines and the liquidation of loss-making companies with up to 60 Mt of capacity, the need for new construction in 2001-2020 is estimated at about 200 Mt. This includes 75 Mt in the Kuznetsk basin, over 70 Mt in the Kansk-Achinsk basin and 20 Mt at the Far East fields. The *Main Provisions* project the opening of ten new deep mines and 16 new open-pit mines, including the following:

- the Kuznetsk basin: seven open-pit mines and five mines (Taldinskoye, Yerunakovskoye, Karakanskoye and Sokolovskoye fields);
- the Kansk-Achinsk basin: three open-pit mines (Berezovskoye and Abanskoye fields);
- the Far East: two open-pit mines and one other mine (Urgalskoye and Elginskoye fields).

In this outlook, the share of coal in TPES will stabilise after the planned increase from 20% in 2000 to 22% in 2010 and 21-23% in 2020. Whether this is possible is not at all clear.

Limiting Factors

The call for production to increase by almost 75% by 2020 would challenge any sector in the Russian economy. It is especially daunting for the coal sector, given that 1999 and 2000 were the first years over the last decade in which coal production increased at all. Although restructuring of the sector is well under way and brought in healthy economic indicators for 1999 and 2000, the range of problems the sector must still face raises concerns as to its ability to meet the challenge. Among the questions to be answered are these:

- Can the coal sector attract private investment to open new mines with state-of-the-art technology?
- Is coal truly competitive as an input fuel for electricity and heat, given the infrastructure already in place for natural-gas use and given actual and projected inter-fuel prices?
- Can price reform be implemented without worsening the non-payment and debt problems?
- How much new infrastructure will be needed and what will be the unit costs of transporting increased volumes of coal across Russia from producing to consuming regions?
- What are the environmental implications of increased coal consumption, in terms of both local pollution or global climate change?

Attracting Private Investment

The World Bank provided support for the restructuring program and did much to make this difficult process more possible. The Bank helped the sector restructure and become a more competitive, profitable and efficient industry, able to attract investment on its own merit. Commercial investments, however, are not the business of the World Bank. Furthermore, an orderly closure of uneconomic mines was a first condition of any further progress. The need now is for investment – direct and indirect, domestic and foreign – to allow the industry to introduce new technologies that will enhance productivity and quality, so that Russian coal can better compete domestically and internationally.

In recent years, there has been debate in Russia over the exact role of the state in encouraging investments in the economy in general, and specifically in the coal industry. The peculiarities of the coal sector, in which investments have long payback periods, are compounded by the specific situation of the Russian coal industry, which has only recently been privatized. The weak banking system limits access to investment financing for any company in Russia. Proponents of budget-financed investments in the coal sector argue that few producers in the industry possess the creditworthiness necessary to obtain the long-term financing required for investments. At the same time, they point to the increasing demand for coal. They argue that unless the State acts now to ensure investments in new productive capacity, there could be an acute shortage of coal in the future. Opponents of state-financed investments question both the propriety of the state's implicit assumption of risk on behalf of private business, and the ability of government bureaucrats to identify and evaluate the best investment projects for a privatized sector (those with the highest returns). While it is generally agreed that there is a role for the state in facilitating investments, the debate over whether it should actually be the provider of finance or use other means to facilitate investments has not yet been resolved.

Restructuring is not the only condition needed to attract investment. The unfinished elements of economic reform that hamper *all* sectors of the Russian economy handicap the coal sector too. They include lack of transparency, the absence of fiscal and legal reform, failure to enforce the rule of law and the need to complete payments and price reforms so that prices cover costs. The coal sector has made great steps in restructuring, but if it is to meet the new challenges, implementation of these general economic reforms becomes essential.

In the first half of 2000, about 3.9 billion roubles were invested in the coal sector, meeting about 50% of programmed investments for the year. As shown in Table 6.8, Russian coal companies increasingly finance their investments with internal resources.

Table 6.8 Structure of Investments in the Coal Sector (%)

	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Federal budget	94%	72%	48%	40%	33%	10%	1%
Own finance	6%	28%	52%	56%	64%	76%	93%
Other sources	0%	0%	0%	4%	3%	14%	6%

The Russian Energy Strategy to 2020 estimates the sector's investment needs to build new, more efficient mines and to obtain up-to-date technology at over $2 billion to 2005 and a further $3-4 billion to 2010. Total investment needs during the period 2001 to 2020 are estimated at between $13-$16 billion. These needs relate to the coal sector proper and do not include infrastructure investments for transportation. Nor do they include the investments in the electricity and metallurgy sectors, which would be required to make increased coal consumption possible, such as new and retrofitted coal-fired power stations with clean-coal technologies.

►►► ***Private Investment is Essential.*** *Private investment in new, efficient mines is essential for the coal sector to meet the challenge of the Energy Strategy.*

There is much discussion in the *Main Provisions* focused on the energy-security aspects of over-dependence on natural gas and the "natural" tendency for consumers to choose coal over gas once inter-fuel pricing is realigned. But the economics of this "tendency" is not clearly defined. Economic analyses covering the full lives of power-stations, including input fuels, transportation costs and environmentally-clean technologies must be made before such decisions can be taken.

►►► ***Competitive Advantage of Input Fuels.*** *Fuller economic analysis of the inter-fuel competition between gas, coal and nuclear will ensure that all factors are considered in adjusting Russia's energy balance. Environmental as well as geographic factors need to be included in the analysis.*

Energy Price Reform

Energy price reform is one of the most important challenges facing the Russian energy sector in the short term. Russian experts blame the partial price liberalisation in the early 1990s – which deregulated oil and coal prices while keeping gas and electricity tariffs regulated – for the excessive dependence on gas in the Russian TPES. Table 6.9 plots the ratio of coal to gas prices over the 1990s, showing clearly the competitive advantage granted to gas over coal as an input fuel. Coal could not compete against gas even as the industry attempted to keep coal prices down. Producers could force the price of coal down only with the subsidies provided to the sector. The *Main Provisions* call for rectification of skewed inter-fuel pricing, so that the ratio between domestic prices for steam coal and natural gas (in terms of tonnes of coal equivalent) should be around 1:1.2 by 2005, with a subsequent shift to 1:1.6-1.8. When coal prices fall below gas prices, coal is expected to regain its competitive advantage and become the fuel of choice for electricity and heat generation.

The Energy Strategy calls for setting prices across all sectors at levels that cover all costs. It foresees coal prices increasing the least, and possibly even falling. Lower production costs are projected, stemming from development of more productive reserves and streamlined industrial organisation. Scientific and technological progress in the production, processing and transportation of coal will also dampen prices. All these factors should come into play increasingly after 2011, due to the expected large-scale development of the Kansk-Achinsk basin. In this period, the *Main Provisions* foresee that coal prices could decrease by 10%-15% relative to prices in 2010. The trend toward cheaper coal is expected to continue in subsequent decades – an important argument in favour of a greater role for coal in the country's fuel and energy balance.

►►► ***Planned Coal Price Reform Encouraging.*** *The Main Provisions' projections to raise energy prices to cover all costs and to realign inter-fuel price competition are encouraging. Coal tariffs should be set at levels that cover all costs.*

Table 6.9 Coal to Gas Price Ratio: 1990s and Outlook* (in Tonnes of Coal Equivalent)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2005*	2007*
Coal to gas price ratio	0.7	3.03	1.45	1.45	1.09	1.3	1.11	1.33	1.06	0.83	0.6

Source: "Main Provisions of the Energy Strategy of the Russian Federation to 2020", November 2000.

The major goals in the short term are to elicit prices that cover costs and to ensure that payments are made in cash for goods sold. In 1998, the coal sector went through a period of massive non-payment by consumers. Non-payments by consumers increased by 14% from the previous year, to 7.5 billion roubles. Some producers actually received cash payments for a fifth or less of the coal they supplied, which pushed up the backlog of unpaid salaries. Practically no funds were set aside for equipment modernisation, mine reconstruction or opencast mines. Cash payments increased in 1999 and 2000 (Table 6.10), but the payments problem continues.

Table 6.10 Non-Barter Payments for Coal and Coal Products (Percentage of Bills)

	1993	1994	1995	1996	1997	1998	1999	2000
Level of cash payment	94%	72%	23%	21%	21%	24%	38%	53%

With the improvement in cash payments came progress in payments of the industry's debts and wage arrears. By mid-2000, wage arrears had fallen to 2.6 billion roubles, equal to about three months' salaries, down from a high of five-and-a-half months' arrears in 1998. Inter-sectoral debts continue to hamper the economy as a whole, but especially the energy markets. The ratio of the coal sector's debts (mainly to the federal and regional budgets, miners and the railroads) to its debt claims (mainly on the electricity sector) reached 2.85 by the end of 2000. The sector owed 83,994 million roubles and was owed 29,461 million.

►►► ***Continued work on non-payments and accumulated debt is essential.*** *Recent success in enforcement of cash payments is promising and needs to continue in all parts of the economy. Accumulated debts between sectors and between producers and consumers of coal need to be resolved.*

Rail Transportation Tariffs

The consequence of the geographic mismatch between regions that produce energy and those that consume it is a huge volume of resource flows. Rail, the most important transport mode for coal, accounts for over 95% of average distances travelled, which range up to 5,500 km depending on the region. Table 6.11 shows current fuel flows between Siberia and the European part of Russia, plus the Strategy outlook's projections to 2020. It indicates little or no increase in natural gas or oil flows, but more than a doubling of coal transport.[111] Coal use is projected to increase sharply in some regions, especially the Urals, where its share in total Russian coal use could increase from 12% in 1998 to 19% in 2010 and 24% in 2020. By contrast, the Kuzbass region's share is projected to drop, from 25% in 1998 to 21% in 2010 and 13% in 2020.

Table 6.11 Current and Projected Fuel Flows from Siberia to the European Part of Russia (as a % of 2000 Levels)

	1995	2000	2005	2010	2015	2020
Natural gas	101%	100%	112-114%	103-105%	103-104%	98-101%
Oil and products	96%	100%	83-96%	75-93%	65-93%	58-93%
Coal	86%	100%	107-127%	127-158%	144-178%	186-220%
Coal, million tonnes	51	59	63-75	75-93	85-105	110-130

Source: Draft Russian Energy Strategy to 2020, Moscow, 2000.

The IEA's *Coal Research* published in 1996 described the problems then plaguing Russian rail networks. "The railway network is in a poor state of repair. It has been reported that about 8.5% of Russia's railways are defective in some respects. The equipment is subject to frequent breakdown and subsequent delays. A lack of line capacity and a shortage of rolling stock also cause bottlenecks; there is an almost perpetual shortage of coal wagons. The problems are exacerbated by inefficient and often corrupt operating practices. Although investment in the railway infrastructure is planned, improvements are unlikely to be implemented in the short term."[112]

With little progress since 1996, it is difficult to envisage Russia's accomplishing the railway improvements needed to realise the outlook. The Railways Ministry estimates

111. In Russia, crude oil is transported mostly by pipeline. Thus, there is no offset between oil and coal in terms of railway infrastructure.

112. IEA CIAB (1996), *"Coal Prospects in Russia"*, Paris.

that it needs over $20 billion between 2001 and 2005 to modernise the system. In recent years it has spent only about half the amount needed to maintain its rapidly ageing assets. The railways cannot finance even day-to-day activities because the government sets regulated passenger prices below cost. Subsidies are insufficient to cover these losses. Arrears reached over $500 million in mid-2000. Cargo tariffs, which cross-subsidise passenger service, were raised again in 2000 by 18.5%, but far below the 50% hike demanded by the railways to make ends meet. Even at current railway tariffs, transport costs averaged just under 30% of total coal production costs in 2000, down from a high of 45% in 1993.

At the urging of the International Monetary Fund, discussion of restructuring the railway monopoly gained renewed momentum in late 2000. The Railway Ministry supports splitting itself into a joint stock company and an administrative body in charge of regulation. Its proposal envisages some competition among rolling-stock companies. Meanwhile, the Ministry of Economy favours a plan to spin off all 17 regional railroads into joint stock companies under the umbrella of a holding company. Thus discussion focuses on whether there should be competition between parallel routes (infrastructure plus train operation), as in Canada and the United States, or between train operators on a state-owned infrastructure, as the EU countries are mandated to implement. Whichever approach is chosen, it is critical that the competition authority (i.e., the Ministry for Antimonopoly Policy) be active in this sector to protect the competition that exists and to prevent anti-competitive behaviour. Given the importance of the railways as the "skeleton" of the entire Russian economy, no room exists for error in its restructuring. This issue is especially critical for the coal sector.

►►► ***Restructuring and Effective Regulation of the Railways.*** *The restructuring of the railways is an essential part of general economic reform. Competition is necessary to convey market signals. The state needs to redefine its role, as the regulator of natural monopolies and not a player. The regulator will need to ensure that all the potential economies of scale in coal transportation by rail are captured and properly reflected in freight charges.*

Environmental and Safety Effects

The Energy and Environment Chapter of this book discusses the environmental impact of coal mining in Russia. It covers air and water pollution and the very great air-pollution impact from using coal in electric power stations and boilers. With the outlook for increased coal production and use, major investments will be needed to reduce environmentally harmful emissions.

Coal mining health and safety conditions have improved slightly, with fewer fatal accidents since 1995 (except for 1997). Fatal accidents ranged between 250 and 300 per year in the early 1990s, then dropped to 179 in 1998 and 141 in 1999. Unfortunately, this trend broke in 2000 when fatal accidents increased to 161. Nevertheless, the number of fatal traumas per Mt of coal produced has fallen from more than 1 before 1995 to the order of 0.6 to 0.8. In 2000, the average was 0.65, with 1.37 fatal accidents per Mt of production at underground mines and 0.13 at opencast mines. As the share of surface mining increases, fatal mining accidents should continue to decrease. Strict enforcement of mine-safety regulations and investment in coal safety remain essential to ensure improved safety standards.

►►► ***Coal mine safety regulations need to be strictly enforced.*** *The coalmine safety regulations introduced in 1995 need strict enforcement, with continued investment in plant and operational health and safety – especially in view of the outlook for increased production.*

COAL EXPORTS AND EXPORT MARKETS

Russian coal exports declined sharply in 1993 at the inception of the industry's restructuring then stabilised around 25 Mt per year from 1994 to 1998. They surged 14% in 1999 to 29 Mt. Russian statistics show a further 21% increase in 2000, to 35 Mt, as the industry moved to expand its presence in Asian and European markets, where it has a transport or a historic brand advantage, or in some cases both. Table 6.12 shows coal exports by destination.

Table 6.12 Coal Exports by Destination in Mt, 1990 to 2000

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
OECD Europe	11.1	10.7	10.8	8.8	6.3	6.7	10.5	10.4	10.0	12.9	15.8
OECD Pacific	9.5	6.3	4.6	3.9	4.3	6.2	5.5	5.5	5.9	6.8	7.7
Other Europe	0.7	3.0	1.5	4.1	4.8	5.8	3.9	2.9	2.7	2.3	4.1
CIS	37.4	31.2	16.4	9.9	7.5	6.9	6.8	4.6	6.4	6.2	5.5
All other	0.5	0.1	0.1	0.4	0.5	0.7	0.8	1.1	0.6	1.1	1.3
Total exports	**59.1**	**51.3**	**33.4**	**27.2**	**23.4**	**26.4**	**27.4**	**24.4**	**25.7**	**29.3**	**35.4**

Source: IEA Statistics, IEA estimates for 1990-1991 and 2000.

Prices for Russian coal increased sharply in 2000, due partly to strong increases in transport costs, as the rail carrier continued to take advantage of strong market conditions to pass on costs. Prices also reacted to strong demand – in Europe for the full year and in the Pacific for the second half. In the Atlantic-Mediterranean market, prices for Russian steam coal increased by from 19% to 40%. In the Pacific market the increase was about 8%. Metallurgical coal prices strengthened as well, although not as much. Prices moved about 3% higher in the Atlantic market and increased 2% to 7% in the Pacific market.

Table 6.13 shows Russia's major coal export brands. Neryungrisky brands of low volatile steam and metallurgical coal are produced for the Asian market by Yakutogol in the Saha region of the Far East. This coal moves by rail to ports on the Pacific – primarily Vostochniy, where large ocean-going vessels, up to capesize (more than 100,000 Dwt), can load. These coals have maintained a strong presence in the Japanese coking and industrial market. Low and medium-volatile coking and steam coals like Batchatsky and Kuznetsky come from the Kemerovo area of the Kuzbass and move thousands of kilometres to the Pacific ports as well as to Murmansk, Baltic exit points and Black Sea ports in Russia and Ukraine. Companies in the Kuzbass area increased production 5% to 6% in 2000. Kuzbassrazresugol, the company which produces Batchatsky coal, announced the completion of a 2 Mt/year washing plant in November 2000, which will target export markets with high-quality steam coal. These steam coals expanded their export market share in both Asia and Europe in 2000.

The joint development of the Murmansk bulk-loading facility by the coal-trading company Coeclerici and the local port authority has had notable success. Ship capacity increased from handy-size (less than 50,000 Dwt) to panamax (between 60,000 and 100,000 Dwt) in 1999, and in August 2000 the port handled its first capesize vessel. Coeclerici has initiated contracts with coal suppliers in the Kuzbass and Pechora regions to provide steam coal for export through the facility. The Murmansk terminal is now rated at 2 Mt per year.

Table 6.13 Main Russian Metallurgical and Thermal Coal Brands

Brand	Calorific Value	Ash (%)	Sulphur (%)	Volatile Matter (%)
Thermal coals				
Tuguni	5,475	16	0.6	44.5
Bachatsky	6,430	12	0.5	20
Kuznetsky SS	5,795	17.5	0.5	29
Neryungrisky SS	6,805	9.5	0.3	20
Denisovsky SS	5,250	17	0.35	21.5
Coking coals				
Neryungrisky K9	7,388	9.5	0.18	18
Kuznetsky G6	6,075	14	0.4	41
Bachatsky SS	6,800	6.1	0.4	17

Source: "Coal Information", IEA, 2001.
Note: Calorific value is the energy content of the coal in kcal/kg.
Ash is measured as a percentage of ash by weight (the lower the better). It is inert matter, which has no energy content, emitted as particulates unless a precipitator is used on the boiler.
Sulphur is measured as a percentage of sulphur by weight. The lower the value the better as it combines with oxygen in the combustion process to create sulphur oxides and sulphuric acid, harmful to the population and the upper works of the boiler and stack fittings.
Volatile matter is measured as a percentage of volatile matter by weight. It is made up of non-carbon constituents that combust with coal. As it supports the flaming of coal, it is desirable for steam coal but undesirable in coal for coke oven coke.

Planned Increases in Capacity at Existing Export Mines

Although a clear schedule of mine capacity increases is not available, announcements by individual companies and coal-industry trade publications suggest that in the near term several mines will expand to supply both domestic and export customers. Expansion plans at existing mines currently focus on the Kuzbass and Far Eastern mines, which supply coking and thermal coal.

A key factor in near-term export capacity is the capability of Russian ports. The Baltic and Black Sea ports, which handle smaller, handy-sized vessels, have a current capacity of 22 Mt/year. The addition of Murmansk brings port capacity for the Atlantic and Mediterranean coal market up to 24 Mt/year. Development of Ust Luga near St. Petersburg will add another 8.5 Mt/year, but progress has been slow and ship capacity would remain at handy-sized (less than 50,000 Dwt) for the foreseeable future. Capacity in the Pacific stands at about 13.7 Mt/year, with ship-size capability up to capesize. Discounting Ust Luga for the 2001 and 2002 seasons, total port capacity is about 38 Mt/year. As a result, no matter how much output expansion occurs, Russian hard-coal exports can increase by only 8% to 10% in the next two years. Future expansion depends on development of the port capacity necessary to trans-load additional volume to ocean-going vessels.

Coal Export Outlook

Russia possesses vast coal resources and is moving towards competitive extraction costs. Market conditions could evolve which would result in high enough prices in international coal markets to cover both the coal extraction costs and the internal transport costs. Russia has a sustained interest in maintaining its presence in the seaborne market, and will undoubtedly play a significant role if business conditions warrant. However, a focus on domestic needs, combined with the long internal transport distances for exports will mean that their development will be an ancillary activity. Exports are not expected to increase as dramatically in the near future as in 2000. Throughout the outlook period, projected coal exports remain flat, at about 20 Mt per year. The new direction in energy policy, which increases the emphasis on domestic coal consumption vs. that of natural gas, fits well with a flat export outlook. Nevertheless, as long as domestic prices remain lower than those in export markets, and as long as payments problems continue, the export market will remain extremely attractive to Russian coal producers.

Russia faces a disadvantage in increasing its share of the highly competitive international coal market. Competitors generally exploit high-quality coal deposits relatively close to ports, allowing easy access to international markets. This is not possible in Russia, given the remote locations of most of its coal deposits and the huge transport distances and costs involved. There are some notable exceptions. Deposits in Russia's Far East have successfully supplied Japanese coking-coal markets. The investment in increasing export-terminal capacities at Ust Luga, west of St. Petersburg, could increase coal transhipment capacity by 8 Mt/year to European and Mediterranean markets. But foreign-material contamination of export coal shipped from Russia often causes problems in the international market. Investments in coal-processing plants will be needed to enhance coal quality if Russia's export potential is to be realised.

7. NUCLEAR ENERGY SECTOR

EXECUTIVE SUMMARY

Structure of the Nuclear Energy Sector

The nuclear energy sector, including nuclear power plants (NPPs) and their supporting organisations, belongs to the Russian Ministry of Atomic Energy (MinAtom). Since 1992, all nuclear power stations have operated under the state company Rosenergoatom[113] (with the exception of the Leningrad NPP, which is independent). Several large firms, which provide support to NPPs have also been restructured as joint-stock companies with MinAtom holding the majority of the shares. Companies which service NPPs also operate under Rosenergoatom. In January 2000, 29 commercial nuclear reactors operated in Russia at nine sites built between 1971 and 1993. Within the next eight years, all units designed before issuance of the basic safety regulations in 1973 will reach the end of their design lifetimes of 30 years. Units of the second generation will complete their planned lifetime between 2010 and 2020. Extensions beyond design lifetimes are envisaged, but this will require investments in modernization and the special attention of the independent safety regulator, GosAtomNadzor (GAN),[114] especially for the first-generation units if extensions are seriously considered for them.

Performance, Design and Operational Safety

Overall electricity production in Russia fell during the period from 1990 to 1998 by 22%, but the drop was only 12.5% at the NPPs. The economic turnaround in 1999 saw overall electricity production increase by more than 2%, with a jump of almost 14% at NPPs. This trend continued in 2000, with an overall increase of almost 4% and over 7% at NPPs. Although nuclear plants accounted for just under 11% of total installed power-generation capacity in 2000, they provided 15% of total electricity generated or 131 TWh, as the load-factor grew to 69%. The sector demonstrated its potential and readiness to cover more of Russia's future electricity demand. Using all the NPPs' available capacity will be essential to create financial resources for maintaining and gradually increasing their safety. Presentations at a conference sponsored by the International Atomic Energy Agency in 1999[115] recognized that Russia made considerable progress on nuclear safety during the 1990s improving both design and operational safety, particularly for the first generation of NPPs. The Kursk and Leningrad NPPs are now modernising and putting in an extra new safety system in accordance with GAN regulations. Despite all these improvements, safety concerns remain, in particular for the Chernobyl-type RBMK reactors as their original design, without a containment does not correspond to contemporary practice in nuclear safety.

Nuclear Power Safety Regulation

GAN is an executive body that sets and implements state safety regulation for the peaceful use of nuclear energy, nuclear materials and radioactive substances. Since December 1991 the Chairman of GAN is appointed by the President of the Russian

113. Russian State Company for the Generation of Electric and Thermal Power at Nuclear Power Plants
114. The Federal Supervisory Body of the Russian Federation on Nuclear and Radiation Safety
115. International Conference on the Strengthening of Nuclear Safety in Eastern Europe.

Federation. Because most of the NPPs, especially the first-generation units, did not obtain standard, unit-specific licensing as has been the practice in Western countries since the early 1970s, GAN has initiated a re-licensing process. It also carries out regular safety inspections, issues regulatory findings, can levy fines and even restrict operations[116]. The inspections have also demonstrated a need to improve the "safety culture" in Russia. As units of the first generation near the end of their design lifetimes, GAN will face new challenges beyond its daily regulatory activities, as it decides whether or not to issue licenses for lifetime extensions.

Russia's Nuclear Development Strategy

MinAtom formulated Russia's nuclear development strategy in 2000[117] and this was approved by the Government of the Russian Federation. Its predictions of increased nuclear generating capacity are very ambitious. Under an optimistic economic growth scenario for the next 20 years, MinAtom calls for nearly twice as much new NPP capacity, of approximately 37 GW, as was built during the 1970s and 1980s (21 GW) in the centrally planned economy of the former USSR. The goal is to reach annual electricity production in the NPPs of 340 TWh, nearly three times that in 1999. The pessimistic economic growth scenario has very high targets, too – 21 GW of new capacity, including 6 GW needed to replace decommissioned units of the first generation, and total annual electricity production of 235 TWh in 2020.

Factors Influencing Future Development of the Nuclear Sector

In the current transition period, it is difficult to evaluate the Russian government's plans for further development of nuclear energy. A range of influencing factors includes:

- the economic competitiveness of the nuclear option;
- the availability of financial resources and the sector's ability to attract investment;
- the need for a research and development programme to develop a new generation of nuclear plants;
- the need to focus on and increase the financing for improving the safety of existing plants;
- the need to increase the financial and human resources of GAN, so that it can take on all the necessary functions that the plans would entail;
- the need to solve problems at the back end of the fuel cycle and those of waste management;
- public acceptance;
- the need to improve the perception of safety culture.

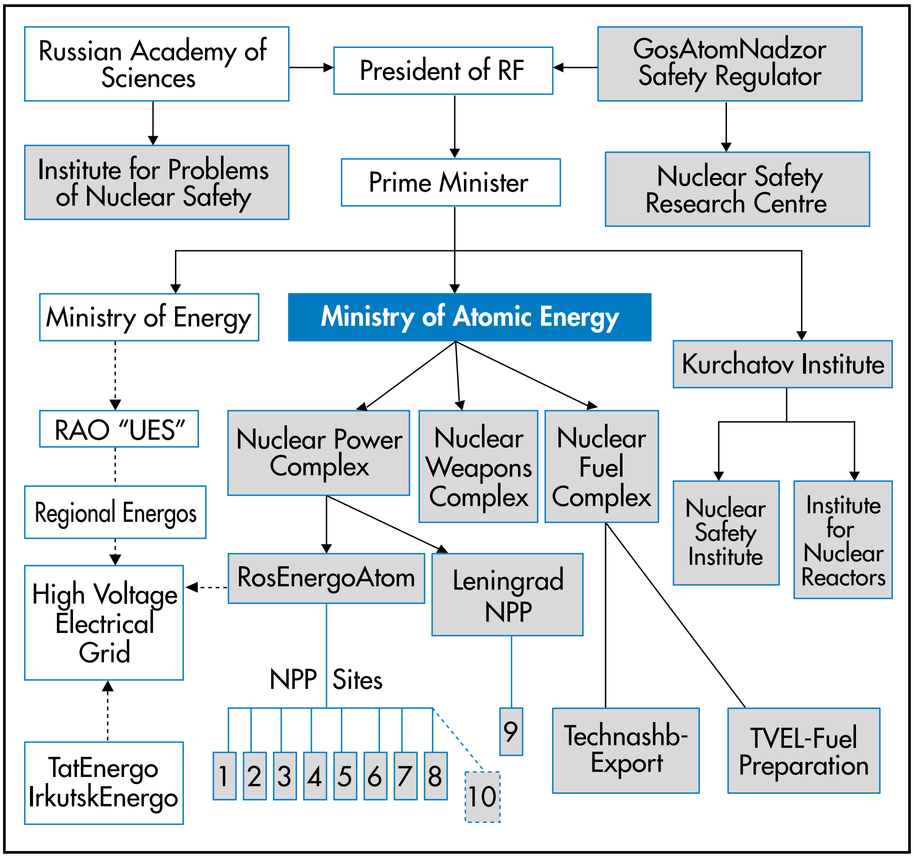
STRUCTURE OF THE NUCLEAR ENERGY SECTOR

The Russian nuclear energy sector has traditionally been an integrated scientific-industrial complex. Its companies operate in all areas necessary to support the nuclear

116. These reflect the increased authority of GAN, a concern expressed in *Energy Policies of the Russian Federation*, 1995 Survey, IEA.
117. The policy is contained in the document, *Strategy of Nuclear Power Development in Russia in the First Half of the 21st Century*, endorsed by the Russian Government on May 25, 2000.

industry. These include geology, ore mining and processing, fuel fabrication, metallurgy, chemistry and radiochemistry, machine and instrument manufacture and construction. It embraces a large number of research and development organisations (Figure 11). GAN, with its technical support organisation, the Nuclear Safety Research Centre, is an independent body, reporting directly to the President of the Russian Federation.

Figure 11 Organisation of the Russian Nuclear Sector



The industry – nuclear power plants and their supporting organisations – belongs to MinAtom, which has tried to convert its military-industrial system into a number of viable commercial companies. Since 1992, all nuclear power stations, except for Leningrad which is independent, have been placed under the state company "Russian State Concern for the Generation of Electric and Thermal Power at Nuclear Power Plants" – Rosenergoatom. Several large companies have also been restructured, as joint-stock companies with MinAtom holding the majority of the shares.

Nuclear Power Plants (NPPs)

In November 2001[118] Russia had 29 commercial nuclear reactors operating at nine sites, with total installed capacity of 21,242 MW: Balakovo, Beloyarsk, Bilibino, Kalinin, Kola, Kursk, Leningrad, Novovoronezh and Smolensk. They included:

118. Rostov Unit 1, VVER-1000 MW, was commissioned in February 2001 and in September 2001 was at 100% capacity. Although it is linked to the grid, official commercial operation will begin only when all procedural tests and safety checks are completed, which takes six months to a year.

- 13 pressurised-water reactors (VVER) including two VVER-417-179 and two VVER-440-230 type units (the first generation), plus two VVER-440-213, six VVER-1000 units (the second generation) and one VVER-1000 unit (the third generation);
- 15 channel-type reactors (11 RBMK and four EGP – channel uranium-graphite reactors);
- one fast-breeder reactor (BN-600).

The existing plants were built between 1971 and 1993. Units designed before issuance of the basic safety regulations in 1973 belong to the "first generation". Twelve units with a capacity of 5,762 MW – Novovoronezh 3 and 4, Kola 1 and 2, Leningrad 1 and 2, Kursk 1 and 2, and four units of the Bilibino co-generation plant make up this generation.

Starting with Leningrad unit 3, put into operation in 1979, almost all further units belong to the so-called second generation. They total 16 – Balakovo 1, 2 and 3, Kalinin 1 and 2, Kola 3 and 4, Kursk 3 and 4, Leningrad 3, and 4, Novovoronezh 5, Smolensk 1,2 and 3 and Beloyarsk 3. They were designed and built in conformity with regulatory requirements such as OPB-73 or OPB-82 "General Design Provisions" and PBYa-04-74 "Nuclear Safety Rules". The last-built unit, Balakovo 4, in operation since 1993, was modified during construction to comply with the revised regulation OPB-88 and may be considered as the first plant of the third generation.

As Table 7.1 shows, all the first-generation units will reach the end of their 30-year design lifetimes within the next eight years. The second-generation units will do so between 2010 and 2020. Because these units represent a relatively cheap source of energy, MinAtom and Rosenergoatom have a strong economic motivation to extend their operational lifetimes. If this occurs, it is essential that necessary safety requirements be met, in line with IAEA lists of the safety issues that need to be addressed at each plant[119]. This will require further investments in upgrades.

►►► ***Lifetime extensions will require investments.*** *The continued operation of existing units beyond their planned lifetimes of 30 years will require financial resources to ensure that necessary safety requirements are met. This will demand the special attention of both Rosenergoatom and GAN, in particular for the first-generation units.*

Today, only the Kalinin-3 unit possesses a valid GAN construction permit and is actively being built. Other units at a very advanced stage of construction, Kursk-5 in particular, are still incomplete after the interruption of their construction during the early 1990s. Work on a total of 18 GW was frozen at various stages in the 1990s, due mainly to budgetary constraints. Among others, these plants include:

- Kalinin NPP (2nd priority) – units 3 and 4 (VVER 1000);
- Rostov NPP (1st priority) – units 1 and 2 (VVER 1000);

119. IAEA reports of the Extrabudgetary Programme on the Safety of VVER and RBMK NPP's, include:
    1. Safety Issues and Their Ranking for WWER-440 Model 230 Nuclear Power Plants, IAEA-TECDOC-640, 1992
    2. Safety Issues for WWER-440 Model 213 Nuclear Power Plants, IAEA-EBP-WWER-03, 1996
    3. Safety Issues for WWER-1000 Model 320 Nuclear Power Plants, IAEA-EBP-WWER-05, 1996
    4. RBMK Nuclear Power Plants: Generic Safety issues, IAEA-EBP-RBMK-04,1997

- Kursk NPP (3rd priority) – unit 5 (RBMK 1000);
- Balakovo NPP (2nd priority) – units 5 and 6 (VVER 1000);
- Beloyarsk NPP (2nd priority) – unit 4 (FBR BN 800);
- Bashkiria NPP (1st priority) – unit 1 (VVER 1000);
- Novovoronezh NPP (2nd priority) – units 6 and 7 (VVER 1000);
- Rostov NPP (2nd priority) – units 3 and 4 (VVER 1000);
- Tatar NPP (1st priority) – unit 1 (VVER 1000).

Pre-construction work was also interrupted on several new sites representing a total capacity of 20 GW. The frozen projects and prepared sites for new units play a key role in MinAtom's plans for the further growth of nuclear power in Russia.

PERFORMANCE, DESIGN AND OPERATIONAL SAFETY

Performance

Although nuclear plants account for only 11% of total installed power-generation capacity, they provided 14.4% of total electricity generation in 1999 and 15% in 2000, producing 131 TWh of electricity (Table 7.2), almost exclusively as baseload production. This share is lower than in most OECD countries (Figure 12).

Figure 12 Share of Nuclear Power in Total Electricity in Russia and OECD Countries (1999) by Percentage

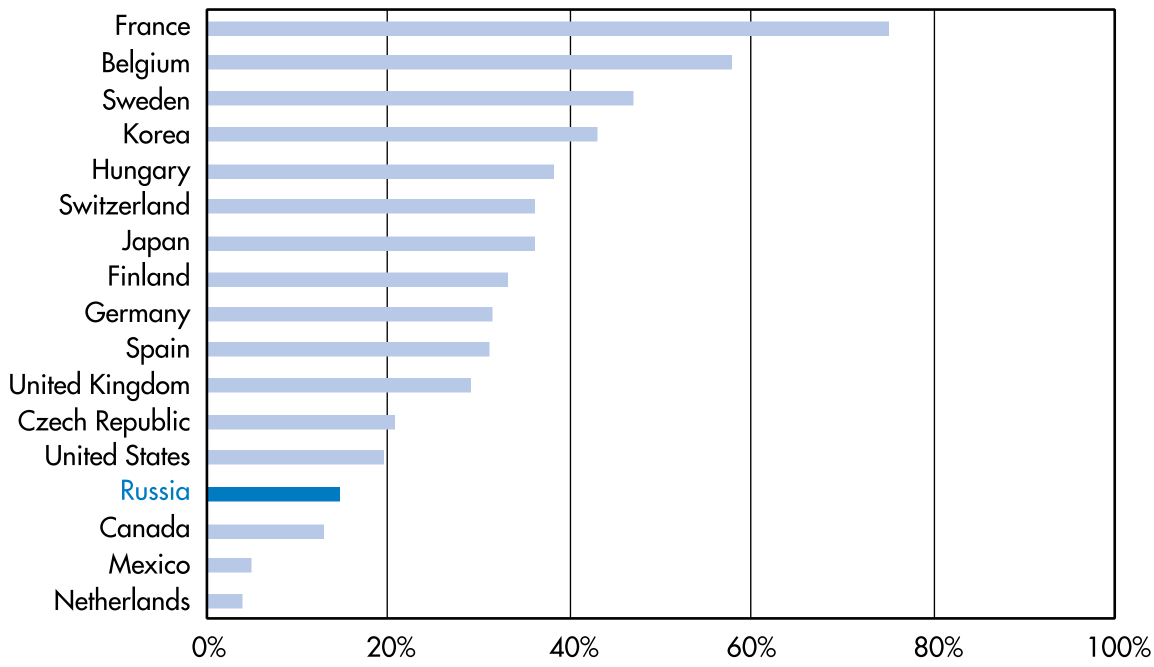


Table 7.1 Russian Nuclear Power Plants (NPPs) in 2001

Connection to the Grid	NPP	Unit No.	Reactor Type	Remaining Design Lifetime from 2001
		First generation NPPs		
12.12. 71	Novovoronezh	3	VVER-417 (179)	1
28.12.72	Novovoronezh	4	VVER-417 (179)	2
29.06.73	Kola	1	VVER-440 (230)	2,5
21.12.73	Leningrad	1	RBMK-1000	3
12.01.74	Bilibino	1	EGP-6	3
09.12.74	Kola	2	VVER-440 (230)	4
30.12.74	Bilibino	2	EGP-6	4
11.07.75	Leningrad	2	RBMK-1000	4,5
22.12.75	Bilibino	3	EGP-6	5
12.12.76	Kursk	1	RBMK-1000	6
27.12.76	Bilibino	4	EGP-6	6
28.01.79	Kursk	2	RBMK-1000	8
		Second generation NPPs		
07.12.79	Leningrad	3	RBMK-1000	9
08.04.80	Beloyarsk	3	BN-600	9,5
31.05.80	Novovoronezh	5	VVER-1000 (187)	9,5
09.02.81	Leningrad	4	RBMK-1000	10
24.03.81	Kola	3	VVER-440 (213)	10
09.12.82	Smolensk	1	RBMK-1000	12
17.10.83	Kursk	3	RBMK-1000	13
09.05.84	Kalinin	1	VVER-1000	13,5
11.10.84	Kola	4	VVER-440 (213)	14
31.05.85	Smolensk	2	RBMK-1000	14,5
02.12.85	Kursk	4	RBMK-1000	15
28.12.85	Balakovo	1	VVER-1000	15
03.12.86	Kalinin	2	VVER-1000	16
08.10.87	Balakovo	2	VVER-1000	17
24.12.88	Balakovo	3	VVER-1000	18
17.01.90	Smolensk	3	RBMK-1000	19
		Third generation NPP		
11.04.93	Balakovo	4	VVER-1000	22,5

** When this book was prepared Rostov 1 was in its commissioning phase and working at 100% capacity. See footnote 118, p. 173.*

The load factor of Russian nuclear power plants reached 69% in 2000, up from 64% in 1999 and 58% in 1998 (Table 7.2). Worldwide average load-factors range between 75% and 80%, although some countries report 88%. Thus Russia has the room to raise its load factor by more than 15%, including up to 5% on account of more effective fuel utilisation. Planned maintenance, including modernisation of the first-generation units, represented about 25% of the load-factor value in 1999. Unplanned losses of electricity generation in that year, of more than 20 TWh, reached nearly 11% of load-factor value. The basic causes were:

- Untimely delivery of nuclear fuel 0.8%
- Non-scheduled maintenance and repairs 0.8%
- Restrictions by the regulatory body (GAN) 4.4%
- Malfunctioning equipment (Operational events) 1.7%
- Grid dispatcher restrictions 1.5%
- Fuel campaign completion[120] and other regulatory requirements 0.9%
- External circumstances (environmental changes) 0.1%
- Others 0.1%.

Table 7.2 Nuclear Electricity Production: 1990-2000 (in TWh)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Nuclear	118.3	120.0	119.6	119.2	97.8*	99.5	108.8	108.5	103.5	122.0	131.0
Total electricity production	1,082	1,068	1,008	957	876	860	847	834	826	845	876
Nuclear's share (%)	10.9	11.2	11.9	12.5	11.2	11.6	12.8	13.0	12.5	14.4	15.0
Load factor (%)	66.1	67,7	67,3	64,9	52,6	53,4	58,3	58,2	55,6	64.5	69.0

** See explanation below.*
Source: IEA statistics, IEA estimates 1990-1991 and 2000.

Overall electricity production fell during the period from 1990 to 1998 by 22%, but the drop was only 12.5% for the NPPs. Their decreased production was caused by the decline in demand for electricity, planned maintenance, unplanned losses due to reasons described above and by safety-related restrictions. In 1994-95, an even more important cause was GAN's restriction of production at the Kursk first-generation RBMK units of 30%. In the following years, the load factor fell due to extended outages for modernisation and safety upgrading, as well as GAN's additional restrictions on other units. These included Balakovo and Kalinin (VVER-1000), where production was restricted by 10%, due to control-rod insertion problems.

The economic losses caused by under-use of the NPPs' power potential from 1994 to 1998 greatly exceeded the financial resources necessary for their modernisation and retrofitting. From this perspective, it is a positive development for the nuclear industry that electricity generation by Russian NPPs increased in 1999 and even exceeded 1990 levels. In 2000, further load-factor gains boosted output still more (by 5%). Thus nuclear power is demonstrating its potential and readiness to cover more of Russia's future electricity demand. The use of all available capacity will be essential to provide financial resources for maintaining and gradually increasing their safety.

120. Before refueling, the reactor loses power, declining gradually to about 80% of its original capacity. These losses, compared to full power operation, are called "fuel campaign completion".

During the economic and financial crisis in the middle of the 1990s, the NPPs were required to supply electricity, although many of their customers could not pay for their consumption. The non-payment problem led to other difficulties, including a lack of financial resources for new fuel, delayed refurbishment of units and deferred salaries for NPP workers. The situation might diminish the motivation of workers to strive for improved safety culture. Although the situation has improved in recent years, only 65% of electricity produced by NPPs was paid for during the first eight months of 2000. The solution of the non-payment problem lies fully in the hands of the Russian government, because the major non-paying consumers are mainly state-owned companies.

►►► ***Resolution of the non-payments problem is critical to the safe operation of nuclear power plants.*** *Continued improvement in payment rate, in cash payments and payment of workers' salaries is critical.*

Design and Operational Safety

Presentations at an IAEA International Conference on the Strengthening of Nuclear Safety in Eastern Europe in 1999 recognised that Russia made considerable progress on nuclear safety during the 1990s, improving both design safety and operational safety, particularly for the first generation of NPPs. The Russian Federation has taken an active part in a number of international nuclear safety-assistance programmes, and Russia has fully recognised the technical value of international co-operation and assistance. MinAtom and Rosenergoatom have undertaken a number of noteworthy steps to enhance the safety of existing NPPs, starting with a generic concept of safety improvement for each reactor type, then moving on to plant-specific modernisation and safety upgrading plans.

Most attention has gone to the RBMK reactors, because their design had serious deficiencies related mainly to their reactivity control and shutdown systems. Despite all possible improvements, safety concerns still remain, because the original design of these reactors without a containment does not correspond to contemporary practice in nuclear safety. Substantial modifications have been made to all RBMKs to avoid any recurrence of the Chernobyl accident. They are now better able to control the power and to shut down the reactors rapidly. Another key concern was to upgrade their emergency core cooling systems (ECCS), particularly by constructing special buildings to minimise the consequences of simultaneous rupture of several pressure tubes. Such a building was constructed at the Leningrad NPP. Since cracking was revealed in austenitic steel pipeline welds in 1996-98, improved methods of monitoring and repair have become a part of the standard in-service inspection program. A number of other improvements, such as an additional, fully-independent shutdown system, have been delayed, mainly due to lack of financial resources. These and other measures in line with IAEA safety lists for each power plant should be taken before lifetime extensions are granted.

The critical safety issues for the first generation of VVER-440 reactors were the integrity of the primary circuit and the confinement system. The plant design did not include any special provisions to protect against a large break of the primary circuit. Other serious deviations from current safety requirements have been identified, such as insufficient separation and redundancy of the safety systems, embrittlement of the reactor pressure vessel, main steam line isolation and I&C redundancy and independence. All in all, the IAEA has identified more than 100 safety issues. In response, Rosenergoatom has begun a step-by-step refurbishment of the oldest VVER units, particularly Kola units 1 and 2 and Novovoronezh units 3 and 4. Among the first steps, the "leak before break" (LBB) concept was implemented to compensate for deficiencies of the original design in maintaining primary circuit integrity. As a part of the LBB concept, acoustic emission-leak detection systems were installed at the primary circuits of all these units, a problem which significantly minimises the likelihood of sudden large breaks. Ongoing safety upgrading programs have included a number of additional safety improvements. Most of them have already been implemented at Kola units 1 and 2, including reactor pressure-vessel annealing, replacement of the original reactor protection by a new "two-train" system, installation of additional fast-closing main steam-line isolation valves and replacement of the pressuriser safety relief valves.

The second-generation NPPs, in particular VVER 440-213 and VVER-1000, were, in principle, designed in accordance with generally accepted international practice. Nevertheless, some design deficiencies remain and are being addressed. The operation of VVER-1000 units has revealed deficiencies in the quality of manufacturing and reliability of some components, which had to be remedied as a matter of urgency. For the first series of VVER-1000 units, often called the "small series", compensatory measures have already been taken to eliminate the most serious of the potential negative effects.

Since 1991, all NPPs in Russia have performed an annual safety evaluation, and have submitted the results to GAN and the IAEA. The concept of annual reports on "safety culture" also has been developed and applied, based on *Methodological Guidelines for Development of* the *Safety Culture Improvement Programme at NPPs, Institutions and Organisations*, covering such aspects as management of safety, training, and the analysis of human error.

The record of Russian NPPs indicates some positive trends are occurring. Table 7.3 illustrates two of them – the number of reactor scrams and operational events[121] (total versus events reported according to the International Nuclear Events Scale – INES). Table 7.3 also shows that the number of events described as "INES 1 and higher"[122] declined from 32 in 1992 to two in 1999.

Table 7.3 NPP Operational Events and Reactor Scrams, 1992-1999

	1992	1993	1994	1995	1996	1997	1998	1999
NPP operational events	197	159	128	101	83	79	102	88
– INES 1 and higher	32	29	9	4	2	3	4	2
Scram / reactor year	1.4	0.9	0.41	0.55	0.38	0.34	0.34	0.5

121. Reactor "scrams" are unplanned reactor shutdowns. "Operational event" refers to all other unplanned system problems.
122. The INES scale measures the safety significance of unplanned events at nuclear facilities. The scale ranges from 0 to 7, a major accident. INES 1 is defined as an event, which led to operation outside the authorized range – but produced no radioactive contamination inside or outside the facility.

Much remains to be done. Many upgrades and safety-upgrading programmes continue or have not yet started. Considerable effort and financial resources are needed to implement them and to improve the level of safety to international practices.

Fuel Supply and Waste Disposal

Russia has extensive uranium resources, enough, according to MinAtom, to fuel a fourfold increase in nuclear generating capacity. It also has large stockpiles of uranium and, potentially, large fuel supplies from decommissioned nuclear weapons. In the short run, this means that Russia will be a net exporter of uranium and nuclear fuel. But MinAtom is concerned about the longer-term sustainability of the nuclear fuel cycle as now constituted – with little recycling and most uranium being used once and then discarded. Thus, plans for recycling nuclear fuel are seen as a strategic way to further the development of nuclear power in Russia.

About 14,000 tonnes of spent fuel from Russian and some foreign NPPs is now stored mostly in water pools. Reprocessing takes place on a relatively small scale in the old reprocessing facility at the Industrial Association *Mayak*. Existing storage facilities are expected to be full by 2007. Spent-fuel storage is becoming a real challenge for MinAtom, and will play a key role in its future plans.

NUCLEAR POWER SAFETY REGULATION

The Federal Supervisory Body of the Russian Federation on Nuclear and Radiation Safety, GosAtomNadzor (GAN), organises and implements state safety regulation in the use of:

- nuclear energy;
- nuclear materials;
- radioactive substances and products;
- products based thereon for peaceful and defence applications (except for regulatory activities associated with the design, fabrication, testing and application of nuclear weapons and nuclear power installations for military purposes).

Since December 1991, the Chairman of GAN is appointed by the President of the Russian Federation. A Science and Technical Centre on Nuclear and Radiation Safety has been established to support it. GAN's total staff of 1,634 people works at its headquarters in Moscow (145), the Scientific Centre (193) and regional offices in St. Petersburg, Balakovo, Ekaterinburg, Khabarovsk, Novovoronezh and Novosibirsk (1,296).

Under the former political system, no NPPs, including especially the first-generation units, underwent a standard, licensing procedure like those applied in Western countries since the early 1970s. GAN, therefore, had to re-license existing units. A revised *Requirements for Licensing in the Area of the Use of Atomic Energy*, issued in 1997, annulled all the original NPP operational permits. When applying for a renewed license spelt out in the Requirements, an NPP must submit to GAN a set of documents in accordance with clear specifications.

GAN applies a differentiated approach to re-licensing, depending on the generation to which the unit belongs, its service lifetime and operational record. To get long-term licenses, first-generation units must pass an "in-depth safety assessment".[123] Units that have not yet had such assessments are permitted to operate under renewable one-year licenses based on their annual safety assessment reports and other documentation. The second and third– generation units are re-licensed based on other documentation. At the end of 1999, more than 20 new licenses were issued out of a total of 29 applications, 13 of which were long-term ones. In most cases, the terms of the licenses do not exceed ten years, and they have to be renewed before the service lifetimes expire.

In 1999, GAN detected 17,596 incidents[124] of non-compliance with safety rules and requirements (Table 7.4), including 1,126 violations that had not been eliminated by the time specified in the regulatory orders. The 2,365 violations detected in the NPPs resulted in 46 actions, including the load restrictions that continued to be effective for Kursk NPP units 1 and 2 (70% of nominal power). The Balakovo NPP faced load restrictions of 90% for its unit 1 from January to September, unit 2 from January to May and unit 4 from January to March. Kalinin unit 2 had a similar restriction during January.

Table 7.4 Detected Violations, Sanctions and Enforcement in 1999

	Detected Violations	**Fines & Actions**
NPPs	2,365	46
Nuclear power installations	606	5
Radiation hazardous facilities	9,081	493
Architect-design & manufacturing organisations	3,609	12
Nuclear fuel cycle facilities	1,247	18
Nuclear research reactors	688	16
Total	**17,596**	**590**

The inspection statistics suggest two general conclusions. First, GAN's increased authority is expressed through its regulatory findings and enforcement, including such very serious actions as the restriction of operations. In 1999, these restrictions represented more than eight TWh of non-produced electricity, equal to the annual production of a 1,200 MW unit. Second, the relatively high incidence of non-compliance and enforcement actions (not all of them can be attributed to NPPs) indicates that the safety culture remains an issue of the utmost importance. Among the key symptoms are:

- the failure to understand the requirements of the laws and regulations;

123. *Recommendation on In-Depth Safety Assessment of Operating Units with Reactors of VVER and RBMK Types.*
124. Of these only two were above the threshold for reporting to INES (see Table 7.3). As discussed earlier, the number of "INES 1 or higher" incidents at Russian NPPs has declined significantly, from 32 in 1992 to two in 1999.

- a lack of commitments to adhere to legal requirements;
- the perception that regulatory requirements are unjust or too onerous.

►►► ***The need to improve safety culture.*** *Although detected violations decreased in 1999, their number remained too high. GAN, together with the licensees, should analyse the causes. High-level political attention would raise this issue to the status it deserves.*

As units, especially first-generation ones, near the end of their designed lifetimes, it will be up to GAN to grant lifetime extensions or to oversee their decommissioning. In both areas it will first have to develop its regulatory competence. Several draft documents prepared in 1999 indicate that GAN is aware of the situation and has already taken measures to adapt to it. These documents include:

- "Requirements for Evaluation of the Possible Extension of the Design Service Lifetime of Facilities Using Nuclear Energy";
- "Requirements for Evaluation of the Possible Extension of the NPP Unit and Measures to Ensure Safety in (an) Extended Period of Operation";
- "Requirements for the Scope and Content of Documents Justifying Nuclear and Radiation Safety for the Life Extension of NPP Units".

That GAN is directly responsible to the President of the Russian Federation is a sign of its independence and isolation from political and commercial pressures. As Russia's safety regulator, it remains weak in relation to MinAtom and *Rosenergoatom*, which have far greater resources and technical capability. The financial crisis in the second half of the 1990s debilitated it still further. Increasing concern has arisen over whether, with staff cuts in both Moscow and the regions (to 175 and 1,235, respectively in 1999, a drop of about 20% since 1993), it can still carry out its regulatory functions adequately.

►►► ***Adequacy of resources of the safety regulatory body.*** *GAN should analyse its resource needs for present and future tasks – including re-licensing and in-depth safety assessment of existing units, safety upgrading programmes, residual lifetime evaluation and extension and preparation for overseeing the decommissioning of NPPs. The Russian Federation should ensure that GAN has the resources necessary to carry out its extensive and important independent regulatory functions.*

RUSSIA'S NUCLEAR DEVELOPMENT STRATEGY

MinAtom formulated Russia's current nuclear development policy in the document, *Strategy of Nuclear Power Development in Russia in the First Half of the 21st Century,* endorsed by the Russian government on May 25, 2000 (see Map 9). This strategy has become an integral part of the overall energy strategy to 2020, incorporated in the Main Provisions of the Russian Energy Strategy to 2020, approved by the Government on November 23, 2000.

The main policy objectives are:

- sustained safe and efficient operation of the existing NPPs and their fuel infrastructure;
- gradual replacement of operating NPPs of the first generation with third-generation designs embodying improved safety, accompanied by an overall increase in installed NPP capacity;[125] and
- development and commercialisation of a new generation of safer NPPs with improved economic performance (such as thermal reactors with Thorium-Uranium fuel cycle, fast breeders and helium-cooled modular gas reactors).

The projections of the Russian Energy Strategy to 2020 for the nuclear energy sector are based on the assumption of 6% annual GDP growth, with 1.8%-3.2% growth in energy demand and an annual increase of nuclear power generation of 5%. The corresponding optimistic-growth scenario foresees 30-32 GW of installed nuclear capacity in 2010, with a further rapid increase to 52 GW by 2020. Attention focuses on plants whose construction was frozen during the 1990s. These plants total five GW. They include Rostov 1 and 2, Kursk 5, Kalinin 3 and Balakovo 5. Construction of new units will follow later. By 2010, a projected total of 10 GW will come from new construction (Figure 13). Under this scenario, 30 additional new units would be built between 2011 and 2020, when the first-generation units (6 GW) will have to be decommissioned:

- four each at the Leningrad, Bashkir and Tatarstan sites;
- two each at the Novovoronezhskaya, North Caucasus, Rostov, South Urals and Far East sites, as well as at the Archangelsk and Khabarovsk combined heat and power stations;
- two each at the Smolensk-2 and Kursk-2 stations.

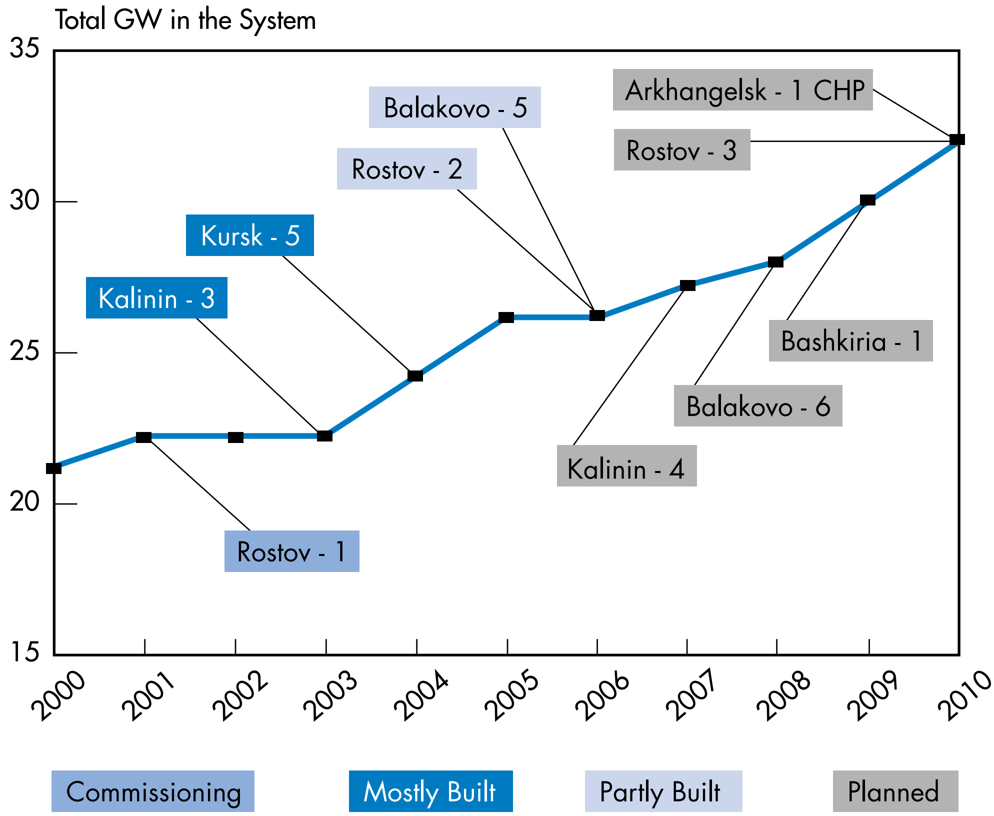
These units will include VVER-1000 and VVER-1500, BN-1600 and VK-300 for combined heat and power stations.

All first-generation units would be replaced by new units after 40-year lifetimes. The second and third-generation units would have their lifetimes prolonged up to 50 years. In this scenario, the expected overall load factor is expected to increase from 69% in 2000 to 82%-85%, representing additional 22 TWh of produced electricity or 3 GW of installed capacity.

If the overall development of Russian economy is slower, the Strategy also includes the pessimistic-growth scenario. In this scenario the installed nuclear power capacity would rise from 22 GW now to 35-36 GW by 2020. By 2010, a projected total of 10 GW will come from new construction, including frozen constructions, with an additional 10-11 GW coming on line from 2010 to 2020, when the first-generation units (6 GW) will be decommissioned. Also this scenario includes ten-year lifetime extensions of all existing units of the first generation, and twenty years for all units of the second and third generation. The load factor is expected to increase to 75% – 82%.

125. The safety concept of the third-generation designs calls for further evolution of existing VVER, RBMK and BN units to meet targets for severe accident frequency specified in the Russian safety standards of the OPB – 88/97.

Figure 13 Planned NPP Construction by 2010



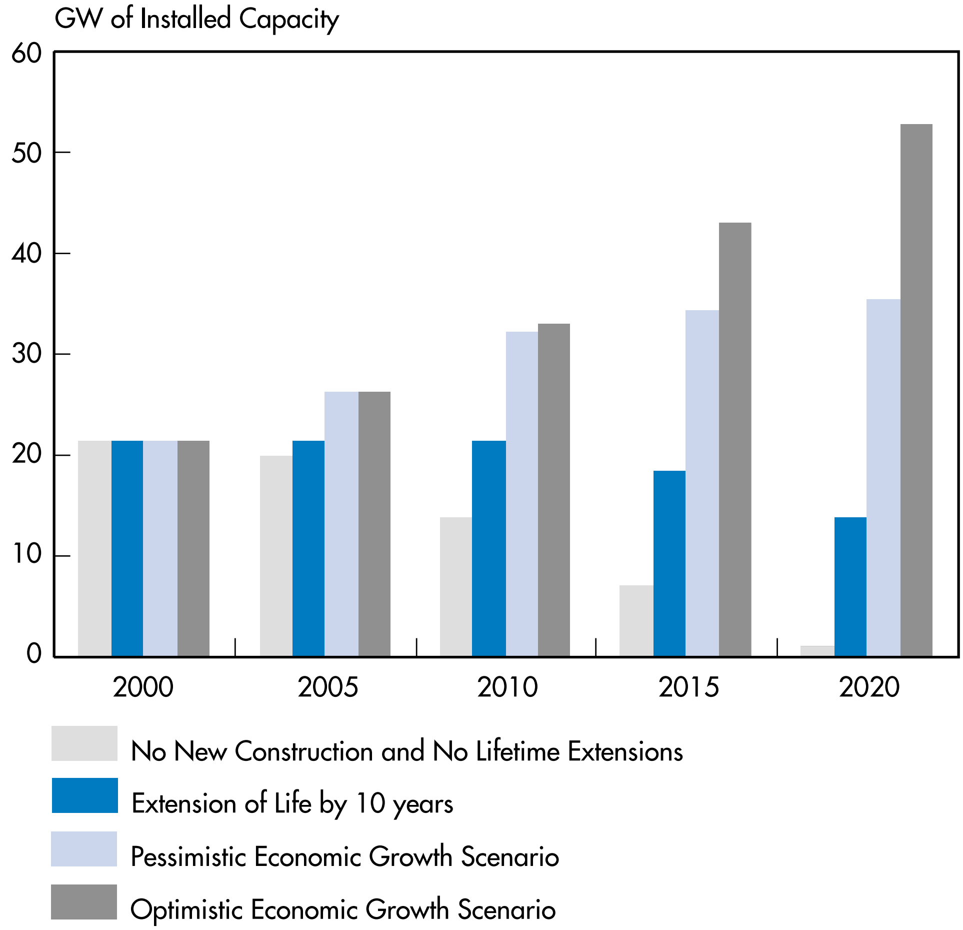
Modernization Planned to 2005:	**Modernization Planned to 2010:**
Kola-1,2; Leningrad-1,2; Kursk-1,2; Novovoronezh-3,4; Bilibino-1,2,3,4	Kola-3; Leningrad-3,4; Kursk-3; Novovoronezh-5; Smolensk-1; Beloyarsk-3

Source: MinAtom, 2001 (This outlook was prepared after the Ministry's strategy was approved).

Figure 14 shows the results of the pessimistic and optimistic economic scenarios, as set against assumptions of no further construction and a policy of 10-year lifetime extensions. The first set of columns represents what would happen after a hypothetical decision to phase out nuclear power and stick to the 30-year design lifetimes of existing plants. In this case, only Balakovo unit 4 would be in operation by 2020 with two to three years of life remaining. The next set of columns assumes the extension of the lifetimes of all existing plants by ten years, with no new plants put into operation. Here, the first generation would generally cease operation by 2018, and three units of the second generation – Leningrad 3, Beloyarsk 3 and Novovoronezh 5 – would do so in 2020. The remaining units built during the 1980s would remain in 2020, with a total capacity of 13,880 GW. The two final sets of columns represent the pessimistic and optimistic growth scenarios of the Energy Strategy.

Table 7.5 and Figure 14 show the projected growth of nuclear power in terms of produced electricity under both economic growth scenarios to 2020. The table also

Figure 14 Installed Nuclear Power Capacity: Outlook to 2020 in GW



Source: Based on "Main Provisions of the Energy Strategy of the Russian Federation to 2020, November 2000".

Table 7.5 Actual and Expected Nuclear Electricity Production, 1990-2020 (in TWh)

Electricity Production	Economic Scenario	1990	1995	2000	2005	2010	2015	2020
Nuclear	Pessimistic	118	100	131	155	190	210	235
	Optimistic	118	100	131	174	212	260	340
Total	Pessimistic	1,082	860	876	970	1,055	1,135	1,240
	Optimistic	1,082	860	876	1,020	1,180	1,370	1,620
Nuclear share (%)	Pessimistic	10.9	11.6	15.0	16.0	18.0	18.5	19.0
	Optimistic	10.9	11.6	15.0	17.2	17.4	18.9	21.0

indicates how nuclear's expected share of total electricity production rises over the period.

The *Main Provisions* consider further growth of nuclear power in Russia inevitable. They take the view that economic recovery and further growth are no longer attainable by increasing the share of natural gas in electricity production. Gas accounted for 43% of electricity generation in 1998, and for 73% in the European part of Russia. The *Main Provisions* raise a number of other economic arguments in support of the nuclear option. Two of them focus on costs. The partly built NPPs, with a total capacity of more than ten GW, will need investment of approximately $680 per kilowatt to be completed. Building new units, will cost about $900/kW, if the construction uses domestic components.

FACTORS INFLUENCING THE FUTURE DEVELOPMENT OF THE NUCLEAR SECTOR

Many uncertainties prevail in the government's plans for further development of nuclear energy, such as:

- the real growth of the Russian economy and its energy efficiency;
- the changing cost of primary energy sources and hence the economic competitiveness of different energy options;
- the ability to attract investment resources;
- the problems at the back end of the fuel cycle, including waste management;
- equally important public acceptance of nuclear power and related political factors.

There is no doubt that Russia has the scientific and engineering capability to expand its nuclear programme by intensifying the construction of new units. Yet questions remain about the pace of this growth and the competitiveness of this sector to attract the massive investments necessary in the emerging market-based economy. Even under the pessimistic economic growth scenario, the next 20 years would see the construction of as much new NPP capacity, about 20 GW, as was built during the 1970s and 1980s in the centrally planned economy of the former USSR. Nuclear plans are even more ambitious under the optimistic economic growth scenario, which foresees 80% more new capacity than under the pessimistic- growth scenario and for NPP electricity production nearly three times that in 1999.

Economic Competitiveness of the Nuclear Option

Proponents of the nuclear option need to prove its economic feasibility in a competitive Russian energy market. The current regulated prices of primary energy sources and electricity, which do not correspond to world energy prices, make such economic analyses very difficult and controversial. Nevertheless, Russian domestic energy prices will inevitably move gradually closer to world prices, in response to economic forces acting to diminish the difference between domestic energy prices and those of exports. This will be even more apparent in the drive to promote energy efficiency and savings, as there will be an incentive to transform these savings into export income by selling "saved" energy resources on the world market.

►►► ***The economic competitiveness of the nuclear option needs to be justified.*** *All realistic considerations of the future development of nuclear energy in Russia should take into consideration the prospect that energy prices will gradually approach world prices and that this will have an effect on investment costs. Another factor to be assessed is the plan for gradual realignment of fuel* *prices to re-establish inter-fuel competition among electricity input fuels. The energy-market deregulation process will need to ensure that the future balance between different energy options will be based on real economic benefits.*

Deregulation of the electricity market would not only lead to market-priced electricity reflecting real production costs, but would also reveal the real capital costs of various energy options. As noted above the Strategy estimates investment needs to build NPPs in Russia, in current economic conditions using domestic components, at about $900/kW. For the existing, partly completed NPPs, the estimates are lower, roughly $680/kW. Recent assessments by Minatom for the partly completed plants are even lower, roughly $400/kW. The Strategy estimates that capital costs for coal-fired plants in the European part of Russia are much higher than for NPPs. It places the competitive investment threshold of NPPs at about $950/kW. Below $950 it is more expedient to build NPPs than CCGT plants in the European regions of Russia, taking into account the need to build underground gas storage facilities and infrastructure to transport gas to and from these facilities.

The assessment of the comparative economics of the various energy options has generated strong controversy inside the Russian Federation. International assessments based on world costs produce quite different results. Based on world prices, the estimated average capital costs of the various options are:

- NPPs – $2,000/kW
- Coal plants – $1,300/kW
- CCG turbines – $ 500/kW[126]

Availability of Financial Resources

Realising the Strategy goals to 2020 will require huge financial resources. The optimistic economic growth scenario which includes the construction of 36 GW (not including Rostov 1 whose construction was completed in 2001) of new NPPs calls for investments estimated by MinAtom at $33 billion, broken down as follows:

- Completion of 5 GW of capacity at nuclear power plant sites already partly built. — $1.9 billion
- Construction of 31 GW of new capacity — $27 billion
- Modernization, safety upgrading and extending the life of existing NPPs (29 units – 21.2 GW) — $2.6 billion
- Manufacturing and renovation of equipment of the 12 first-generation units, having reached the limit of their resources — $1.6 billion

The pessimistic economic growth scenario, including the construction of 20 GW of new NPPs, the lifetime extensions and safety upgrades of first-generation units, calls for investments of more than $19 billion. Real investment costs will likely be much higher as prices rise in Russia. Also cost of decommissioning of the 12 first-generation units during 2010-2020 need to be considered in addition.

126. OECD/IEA report on *Nuclear Power in the OECD*, 2001, p.35

The main financial source for the development of the nuclear program would be revenues from the sale of electricity produced by NPPs. The Strategy also mentioned other potential financial sources, such as the export of Russian nuclear technology, particularly the export of NPPs and nuclear fuel, including spent-fuel services. However, the Strategy was not based on these additional sources. In any case, financial resources are a prerequisite for the planned nuclear energy development in Russia. Some doubts about availability of such huge investments are understandable.

►►► ***A well-defined investment plan is needed.*** *Availability of financial resources is a prerequisite of nuclear energy development in Russia. The Russian government and MinAtom should develop a detailed, realistic investment plan for its nuclear program including all the potential financial resources and their defined use.*

R&D Programme for Development of New Generation Plants

It is hard to see how the construction of the new NPP units over the next 20 years can rely solely on existing, third-generation NPP designs. Over the two decades, new NPP designs are expected to emerge, launching a completely new generation of safer NPPs with improved economics. The Strategy mentions R&D activities, in particular the development of thermal reactors with Thorium-Uranium fuel cycle, fast breeders and helium-cooled modular gas reactors. Such research activities will require the collaboration of a number of research and design organisations. While Russia doubtless has sufficient scientific and technical capabilities to develop a new generation of NPPs, the availability of financial resources for R&D activities will determine its nuclear development programme.

►►► ***A well-defined R&D program is needed.*** *MinAtom should set up well-defined and product-oriented long-term R&D plans with assured financing and aimed at developing a new, inherently safer generation of NPPs with units of large capacity that can replace the first-generation units after 2010.*

Safety Upgrading of Existing Plants

Although the Strategy assumes the extension of the service lifetime of existing units by 10 years and its maximum-development scenario foresees 20 extra years for units of the second and third generations, it does not discuss any related technical, financial, regulatory, legal or political requirements. It is most unlikely that the existing units will simply continue in operation after their designed lifetimes expire. Current Western practice for NPP lifetime extension requires a thorough, in-depth safety assessment of each unit. It focuses, above all, on the residual lifetime of all safety-related components and systems. According to GAN, a similar process will also be applied in Russia. As mentioned earlier, GAN is already preparing the necessary regulatory documents. Some representatives of GAN are of the opinion that every unit that would apply for lifetime extension would have to comply with current safety requirements and regulations. Such a requirement would probably be impossible to fulfil, from either a technical or an economic point of view, especially for the units designed in the 1970s. Strictly applied, it would lead to the closure of *all* the units of the first generation as their lifetimes expire.

►►► ***Minimum safety requirements need to be set.*** *It is essential that the GAN clearly define the set of minimum safety requirements below which the extension of the service lifetime cannot be justified and which will become the basis for plant-specific safety upgrading programmes. These minimum safety requirements should be in line with IAEA lists of safety issues.*

Financial and Human Resources of GAN

GAN's financial and personnel constraints raise questions about its ability to carry out its important regulatory functions at the high standard expected of it. Implementation of the Strategy will mean the construction of new units, possible lifetime extensions of existing units and their later decommissioning, as well as spent-fuel and waste management. This will increase GAN's workload and the range of issues it will have to handle, with additional, extremely high demands on its staff. With these new specific tasks, GAN must develop its expertise through timely training of its safety inspectors.

►►► ***A strong, independent and competent regulatory body is essential.*** *It is evident that the success of implementing the nuclear development strategy depends on effective surveillance by a regulatory body with sufficient resources to meet all challenges. It is in the interest of both the Russian Government and MinAtom that GAN have all these qualifications and necessary resources.*

Solving Problems at the End of the Fuel Cycle and Waste Management

Solutions to the problems of long-term storage or reprocessing of spent fuel and related radioactive-waste management are conditions for any further growth of the nuclear industry. Clearly, Russia's scientific and technological potential, along with its vast territories and very low population density, will ease the search for satisfactory solutions, provided that the issues receive adequate attention and priority. This has not always been the case. Problems associated with the end of the fuel cycle and radioactive waste management have been rather underestimated.

MinAtom, by contrast, has recently introduced the idea of rendering such services to foreign NPPs. It proposes to import 1,000 tonnes of spent fuel a year. In August 2001, Russian President Vladimir Putin approved key legislation allowing the import and reprocessing of spent nuclear fuel.[127] This legislation creates a legal framework for what MinAtom considers "highly profitable" business activities. It estimates that it could raise up to $20 billion in this way, and thus fund the construction and upgrades necessary to realize its ambitious nuclear outlook. The law includes a list of nuclear wastes, which cannot be stored in, or brought into, Russia. The law is also intended to promote environmental security during transportation. National and international controversy regarding these plans shows clearly what Russia needs to do before offering any nuclear fuel-handling services to foreign customers. As a matter of urgency, it must first clean up all its contaminated sites and assure the safe long-term storage of *domestic* spent fuel and radioactive waste. Only when this has been done will it be appropriate to import and treat fuels from other countries.

►►► ***Russia needs to clean up all existing contaminated sites and assure the utilisation and long-term safe storage of domestic spent fuel and radioactive waste.*** *MinAtom should prepare, without delay, a detailed plan for effective long-term management of the end of the fuel cycle and wastes. The plan should deal with existing spent fuel from all kinds of nuclear facilities as well as its expected growth as a result of the implementation of the Strategy.*

127. With up to 90% of potential fuel imports produced in the US or used in US-designed plants, the US government has the final approval as to whether or not the spent fuel can be exported to a third country.

Public Acceptance

Public opinion may significantly affect the future of nuclear power. In Russia, antinuclear groups and environmental movements strive to block any further development of nuclear power. Some of these organisations, like the Centre for Russia's Environmental Policy or the Social-Ecology Union, are strong opponents of the Nuclear Energy Strategy. They declare it to be economically disadvantageous, ecologically dangerous and politically wrong. The "true" state of Russian public opinion is hard to determine. It would be a mistake to rely on its current rather indifferent public expression, as political shifts or a major event could suddenly change it.

►►► ***Public opinion may affect the future of nuclear power in Russia.*** *It would be difficult or even impossible for the Russian Government and MinAtom to promote further development of nuclear power without positive public perception of the nuclear option. An active policy aimed at building public confidence in nuclear power should be an integral part of the Strategy, with a strong commitment to safety-related priorities as an essential component.*

Safety Culture

An absolute imperative for future development of nuclear power in Russia is a sound operating record at existing plants. Any major accident would stop the further development of nuclear power, not only in Russia but in other parts of the world as well. Lessons learned from past accidents around the world show the importance of the human factor and commitment to strong safety awareness. Although the operating record of Russian NPPs indicates gradual improvements in many areas, further improvements need to be strongly sought and maintained.

►►► ***It is critical to improve safety culture.*** *MinAtom should permanently insist on further improving consciousness of safety issues in Russian NPPs and continuously monitor the performance of plants to detect quickly any possible decline in safety. A key part of this effort should be to strengthen knowledge and respect for all legal safety requirements among all NPP workers. This includes strengthening the legal authority of GAN and nurturing full respect for its requirements and decisions.*

8. ELECTRICITY & HEAT SECTORS

EXECUTIVE SUMMARY

Electric Power Generation, Demand and Capacity

Russia is the world's fourth largest generator of electricity, behind the United States, China and Japan. Due to the shrinking of the national economy in the 1990s, generation fell from 1,082 TWh in 1990 to 827 TWh in 1998. Output increased by more than 2% in 1999, however, to reach 846 TWh. Preliminary figures for 2000 indicate a further 4% hike. Under a favourable economic-growth scenario, expected electricity production will reach 1990 levels by 2010. In this new context of strong growth and increased electricity demand, the ability to attract the necessary investments is critical. Furthermore the Russian Energy Strategy places particular emphasis on coal and nuclear to redress what is seen as an over-dependence on natural gas. This raises many questions, including the environmental issues due to increased emissions from coal use and the issue of nuclear safety.

Functioning of the Russian Electricity Market to 2000

A 1992 Presidential decree restructured the Russian electricity sector into a single joint-stock company, RAO UES and established the company Rosenergoatom to operate all nuclear power stations with the exception of the Leningrad NPP. Most electricity-industry activities continue to be vertically integrated within RAO UES. A wholesale market for electricity (FOREM) was also created at this time to increase the efficiency of power trading between surplus and deficit regions.

In the period after 1993-1994 the non-payment problem hit the electricity sector particularly hard at each step from the purchase of input fuels to the settlement of accounts with final customers. Since RAO UES was allowed to disconnect non-paying customers in July 2000, payment rates have increased dramatically, reaching over 90% in the first quarter of 2001 almost double that in the first quarter of 2000. Payment rates for the year 2001 are projected to reach over 100%, reflecting payments of arrears as well. Improved bill collection is expected to advance further reform and investment in the industry. Although guidelines drawn up by the Federal Energy Commission (FEC) call for tariffs that cover the full cost of supply, tariffs continue to be set locally by Regional Energy Commissions (RECs) and do not always cover costs. The continuing economic and political dependence of the regional commissions on local government administrations is an important issue in the tariff-reform process, as short-term political pressures often appear to counter the long-term viability of the industry.

Electricity Sector Restructuring: Plans and Outlook

The electricity-sector restructuring plan approved by the Russian government in July 2001 calls for a three-phase reform of the sector over the period 2001 to 2009. Generating firms belonging to RAO UES are to be reorganised into independent companies. A state transmission company will be formed to handle the high-voltage grid only. The regional *energos* will remain intact, but will be obliged to create separate companies for generation and distribution. A wholesale market will be built up in regions with potential multiple suppliers. The share of the federal and regional wholesale markets is foreseen to increase gradually along with competition. In the first stage of reform, retail prices will remain strictly regulated, although tied to wholesale prices. All firms are to be guaranteed non-discriminatory access to the high and low voltage grids. Key to the plan's success and the viability of the restructured companies will be effective implementation of planned increases in electricity tariffs to levels that cover all costs – and enforcement of payments.

Electricity Exports

UES plans to increase electricity exports to 35 TWh in 2010 from 23 TWh in 1999. Most of the expected increase is to go to Western Europe, but generating capacity in that market is already abundant and so the need for imports from Russia may be problematical. Exports to CIS countries are fraught with non-payment problems; they have decreased substantially in the past few years.

Heat Sector

It is hard to separate the electricity and heat sectors in Russia, since about 30% of electricity is produced by co-generation, essentially as a by-product of heat. The two sectors are also closely interconnected by effective cross-subsidies, in which electricity sales provide for losses incurred in heat generation. District heating systems provide heat and hot water to most of Russia's urban population. A large potential exists for energy savings in district heating, especially through the reduction of losses and implementation of energy efficiency measures. Only after this stage is completed will the installation of meters and heat-regulating devices to allow for demand-side management be effective.

ELECTRIC POWER GENERATION, DEMAND AND CAPACITY

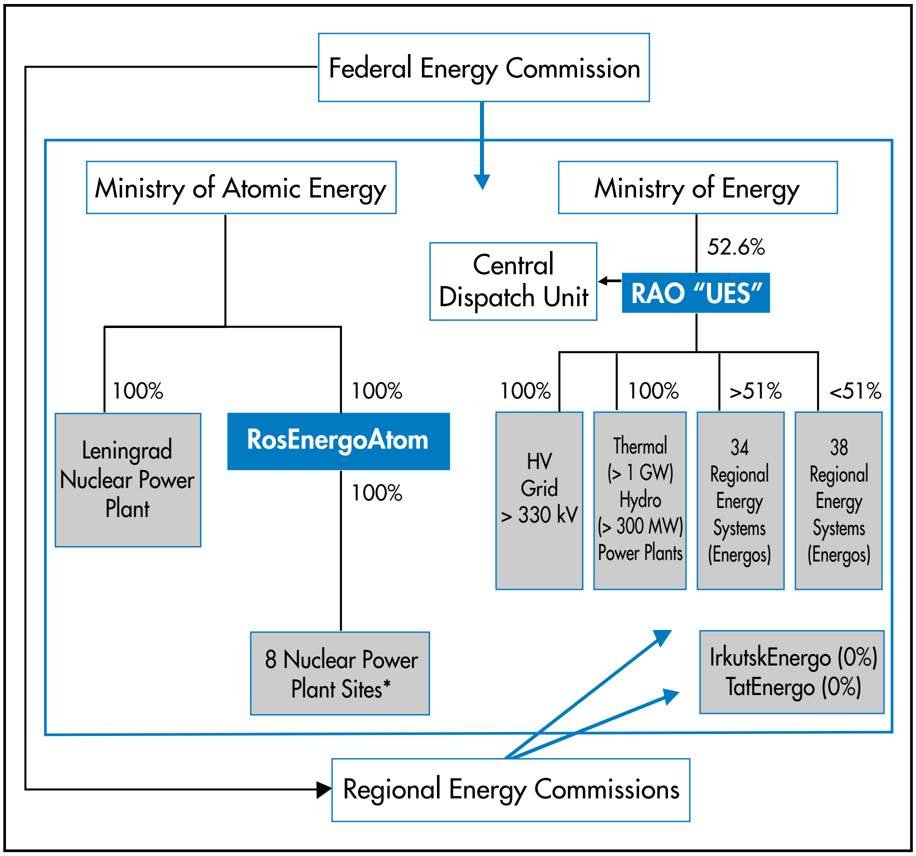
Structure of the Electricity Sector

In 1992 Presidential Decrees No. 922 and No. 923 transformed the Russian electricity sector, with the exception of nuclear generators, into a single joint-stock corporation, United Energy Systems (RAO UES). The federal government continues to be the company's principal shareholder. At the end of 2000 it held 52.6%.[128] Figure 15 illustrates the industry's structure in 2000. The restructuring plan approved in mid-2001 will lead to changes in the structure of RAO UES and Rosenergoatom.

In 2000, the installed generating capacity of RAO UES was 156.2 GW or 73% of Russia's total. The company encompasses:

128. The next biggest block is held by the Bank of New York International Nominees (19.07%), with the remaining distributed among employees or floated on the Moscow stock exchange. In total, foreign shareholders hold 30.6% of the corporation.

Figure 15 Electricity Industry Structure, 2000



** When this book was prepared Rostov 1 was in its commissioning phase and working at 100% capacity. See footnote 118, p. 173.*

- 72 of the 74[129] regional "*energos*", which supply electricity and heat, including:
  - 34 in which RAO UES holds greater than 51% of the voting rights;
  - 36 in which RAO UES holds from 25% to 49% of voting rights;[130]
  - 2 in which RAO UES holds less than 25% of voting rights;
- thermal power plants (greater than 1 GW) making up 78% of Russia's installed thermal capacity (122.4 GW);
- hydro electric plants (greater than 300 MW) making up 22% of Russian hydro capacity (33.8 GW);
- the national grid (all transmission networks of 330 kV and above);
- the Central Dispatch Unit, which controls the networks of the regional and independent joint-stock companies;
- 57 research and design institutes;
- 29 construction, maintenance and other companies.

129. There are two *energos* in which UES has no shareholdings: *Irkutskenergo* (13 GW) and *Tatenergo* (7.1 GW).
130. In the case where RAO UES holds only 49% participation, it still often controls a majority of voting shares.

Power Generation

Russia is divided into seven regional grids or energy systems (ES). Almost 75% of Russian electricity is produced in three of them: Urals, Siberia and Central. Primary fuel use shows significant regional diversity (Table 8.1). Nuclear-power production is largest in the Northwest system, and makes up about 25% of production in the Central and Volga systems. Hydro electricity accounts for almost half of production in the Siberia system and almost a quarter in the Volga and Far East systems. Thermal power generation accounts for 70%-90% of production in the Urals, North Caucasus and Far East, and over half in the Siberia, Volga and Central systems.

Table 8.1 Regional Breakdown of Electricity Generation by Plant Type in 1999 (by %)

Energy System	By Region	Thermal	Hydro	Nuclear	Other	Total
Urals ES	25.9	90.2	3.0	2.1	4.7	100
Siberia ES	24.6	47.9	48.6	0.0	3.5	100
Central ES	22.4	59.8	7.4	28.2	4.5	100
Volga ES	9.9	53.2	23.1	23.1	0.6	100
Northwest ES	5.7	32.9	17.6	41.0	8.5	100
North Caucasus ES	5.6	81.4	16.2	0	2.3	100
Far East ES	5.3	71.7	27.4	0.6	0.3	100
Other*	0.6	0	100	0	0	100
Total	100					

** Isolated electricity systems, districts and plants.*
Source: InformEnergo, 2000.

Russia is the fourth largest generator of electricity in the world, behind the United States, China and Japan. In 1998 it generated 827 TWh, down from 1,082 TWh in 1990. Electricity generation increased over 2% in 1999 to approximately 846 TWh. Preliminary figures for 2000 show output of 876 TWh, some 4% above 1999.

Fuel shares in power generation, including those in combined heat and power plants (CHPs), remained relatively unchanged between 1990 and 1999, with only a slight increase in the share of coal at the expense of heavy fuel oil (Table 8.2). In 1999 natural gas accounted for 42% of electricity generation, followed by coal (19%), hydro (19%), nuclear (14%), and oil (5%). Generation from renewable energy (other than hydro) accounted for less than 0.2%. In thermal heat and power production, natural gas maintained a share of about 64% throughout the 1990s, while heavy fuel oil's share dropped from about 16% to 7%, and that of coal increased from about 20% to 29%.

The share of natural gas in the fuel mix for thermal power generation in the European part of Russia rose from about 68% in 1990 to almost 73% in 2000. Concern about an excessive dependence on natural gas has strengthened proposals to increase the share of coal. The *Main Provisions of the Russian Energy Strategy to 2020* calls for coal's share in the European part of Russia to rise from about 17% in 2000 to 30% by 2020. To achieve this would require either more transportation of coal or more transmission lines from coal-producing regions. An alternative scenario by MinAtom proposes an increase in the share of nuclear in the overall mix for power generation in the European part of

Table 8.2 Electricity Generation, by Fuel (TWh)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Total Electricity Generation	**1,082**	**1,068**	**1,008**	**957**	**876**	**860**	**847**	**834**	**827**	**846**
Natural gas	512	502	461	430	364	354	365	357	346	359
Coal and coal products	157	155	154	149	163	161	161	157	163	161
Hydro-electricity	166	168	172	173	175	175	153	157	158	160
Nuclear	118	120	120	119	98	100	109	108	105	122
Petroleum products	129	124	100	83	73	68	57	52	53	41
Combustible renewables	0	0	2	2	2	2	2	2	2	2

Source: IEA estimates for 1990-1991, IEA statistics 1992-1999.

Russia from 20% in 2000 to 37% in 2020. The Main Provisions consider the proposed increase in the share of coal as a safeguard against a failure of meeting ambitious increases in nuclear power generation capacity.

The economic turnaround in 1999 and 2000 and the resulting increase in electricity demand heightened concerns about primary fuel supplies for power generation, especially natural gas. The *Main Provisions* project overall gas consumption at power stations to remain nearly unchanged through 2005[131], with little increase expected thereafter, while coal consumption is expected to increase by some 150% to 200% by 2020. In view of the forecast doubling of electricity generation, this implies a decrease in the share of gas-fired thermal power generation from 61% to 51%, and an increase in the share of coal-fired thermal power generation from 31% to 44%. In terms of *total* power generation, including nuclear and hydro-power generation, the share of gas fired generation is expected to fall from 42% to 34% while the share of coal-fired generation will increase from 17% to 29% (Table 8.3).

An alternative scenario encompassed in the *Main Provisions* and described in much more detail in the Ministry of Atomic Energy's *Strategy of Nuclear Power Development in*

Table 8.3 Outlook for Electricity Generation by Fuel to 2020

	2000	2005	2010	2015	2020
Natural gas	42%	38%	39%	38%	34%
Coal and coal products	17%	24%	27%	27%	29%
Hydro-electricity	18%	17%	16%	14%	12%
Nuclear	15%	15%	15%	17%	21%
Petroleum products	7%	5%	3%	3%	3%
Combustible renewables	1%	1%	1%	1%	1%

Source: Main Provisions of the Energy Strategy of the Russian Federation to 2020, November 2000.

131. In October 2000, RAO UES stated that *Gazprom* planned to cut gas deliveries to it by nearly 30% in 2001, a reduction to 95 BCM from 134 BCM in 2000. When *Gazprom* threatened to do this earlier in 2000, presidential pressure forced it to continue supplying gas at close to usual amounts.

Russia in the First Half of the Twenty-first Century, projects a much stronger growth in the share of nuclear power generation (as opposed to that of coal) to replace the decreasing share of gas. Table 8.4 below illustrates this alternative outlook for the electricity fuel mix, which assumes the more ambitious nuclear development program is achieved in the context of the optimistic economic growth scenario. In this scenario, the share of nuclear power generation increases from 15% currently to about 30% by 2020, or from about 20 GW to a maximum of 50 GW. In 1999, increased production from nuclear plants already absorbed some 90% of power consumption growth, at load factors of 64.5%. The load factor increased again in 2000 to 69 %, and nuclear-generated electricity increased 7.5% over 1999. Thermal and hydro generation increased by only about 3%. Thus, nuclear power continued to raise its share in electricity production.

Most of the increase in nuclear generation in 1999 and 2000 came from increased load. Future gains would come from plants whose construction was halted because of the Chernobyl accident and the economic crisis of the early 1990s.[132] These plants reportedly can be commissioned quickly and at relatively low cost once they meet current safety standards. The nuclear sector's plan to double its share in total electricity production over the next 20 years faces, however, a number of serious limiting factors. The Ministry of Energy's plan to increase the share of coal over natural gas is also ambitious.

Table 8.4

Alternative Scenario for Electricity Generation by Fuel to 2020

	2000	**2005**	**2010**	**2015**	**2020**
Natural gas	42%	38%	32%	23%	22%
Coal and coal products	17%	19%	19%	23%	20%
Hydro-electricity	18%	17%	16%	15%	14%
Nuclear	15%	18%	22%	27%	30%
Petroleum products	7%	8%	9%	8%	8%
Combustible renewables	1%	1%	2%	4%	6%

Source: MinAtom, 2001

Electricity Consumption

During the economic decline that began in 1990, final consumption of electricity decreased by more than 30%, to 579 TWh in 1998. Electricity demand fell in all sectors except the residential one, where it actually increased by 26% (Table 8.5). Overall electricity demand increased in 1999 to 593 TWh for the first time in the 1990s, and consumption in 2000 was estimated at 614 TWh, an increase of almost 4%. It is interesting to note that electricity losses in the generation and transmission stage in Russia are close to 20 percent which is about 8 percent higher than the OECD average. Moreover, in Russia, electricity lost in transmission is more pronounced than the amount of electricity used in power plants.

The rise in the residential sector's share between 1990 and 1999 (from 13% to over 24%) was exceeded by the decline in the industry's (from 58% to 50%). The share of

132. Note that Rostov, Unit 1, VVER-1000 began operation in mid-February 2001.

Table 8.5 Electricity Balance, 1990-1999, in TWh

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Electricity generation	**1,082**	**1,068**	**1,008**	**957**	**876**	**860**	**847**	**834**	**827**	**846**
Imports	35	35	28	25	24	18	12	7	8	8
Exports	43	47	44	43	44	38	32	27	26	23
Domestic supply	**1,074**	**1,056**	**992**	**938**	**855**	**840**	**828**	**814**	**809**	**832**
Total energy sector	163	161	152	144	135	139	142	140	137	143
• coal mines	13	12	12	13	12	11	10	9	8	8
• oil & gas extraction	55	52	47	43	40	40	41	41	41	45
• oil refineries	15	14	13	12	11	11	12	11	10	12
• own use	72	74	70	67	62	59	61	61	65	65
• non-specified	8	8	9	9	10	18	19	18	13	13
Distribution losses	84	84	84	88	85	83	84	84	93	96
TFC	**826**	**811**	**756**	**706**	**635**	**618**	**601**	**590**	**579**	**593**
Industry	482	461	419	376	318	314	294	292	283	296
Transport	104	97	87	77	68	65	65	63	60	61
Agriculture	67	70	70	69	61	53	49	42	38	34
Services	67	67	65	62	61	60	61	60	62	62
Residential	107	116	116	121	126	126	132	133	135	140

Source: IEA estimates and statistics.

agriculture also dropped, while that of transportation stayed about the same. Industrial electricity consumption fell most strongly in the chemicals and petrochemicals, machinery, construction, textiles and leather branches. Electricity consumption patterns in 2000 were closer to those in OECD countries than in 1992, although industry's share was still much higher than the OECD norm (Table 8.6).

Table 8.6 Structure of Electricity Consumption, 1999

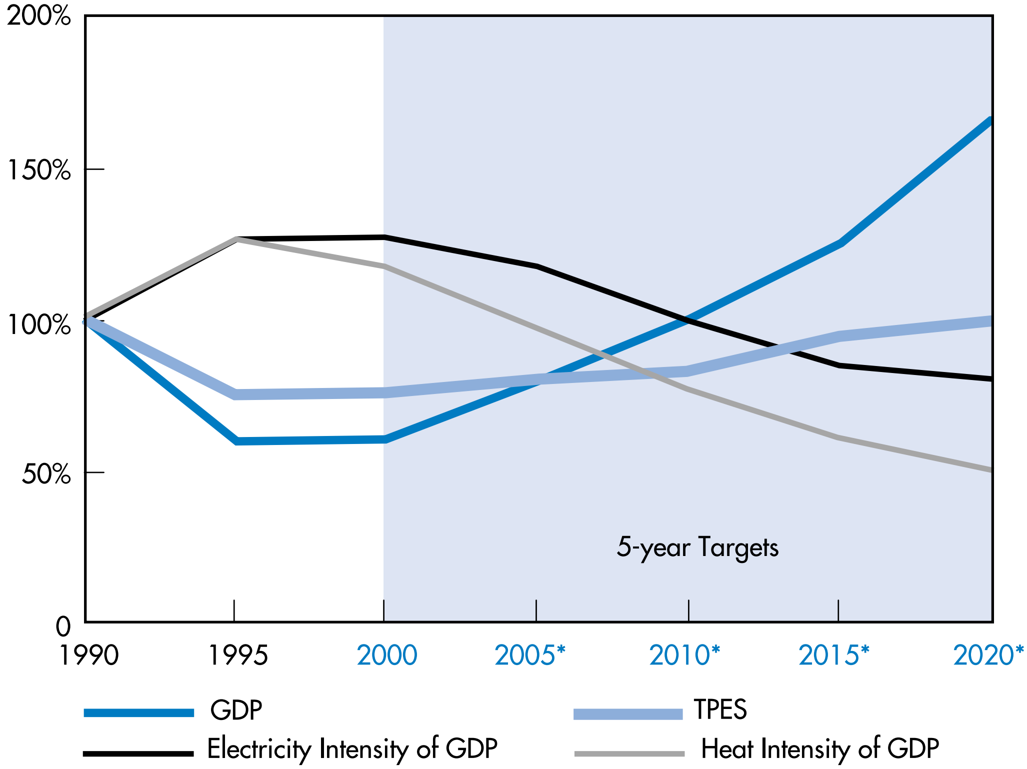
	Russia	OECD Average
Industry	50%	39%
Residential	24%	31%
Commerce & public	10%	28%
Transport	10%	1%
Agriculture	6%	1%

Source: IEA statistics.

Industrial consumption fell by less than the 29% decline in GDP. As a result, Russia saw its already very high electricity and energy intensity increase. According to Russian statistics, the electricity intensity of GDP increased from 1.08 kWh per US dollar in 1990 to 1.37 kWh per US dollar in 1995, and to just over 1.39 kWh per US dollar in 2000.[133] Figure 16 provides the outlook for energy intensity from the *Main Provisions*. It forecasts a constant decrease in electricity (and heat) intensity of GDP, with electricity consumption expected to grow by 21-25% from 1995 to 2010 and by 140-180% to 2020.

133. This does not take into account the estimations of under-reporting of Russian GDP, in the order of 20-50%.

Figure 16 Outlook for Electricity and Heat Intensity, % Change from 1990



* Outlook in "Main Provisions of the Energy Strategy of the Russian Federation to 2020", November 2000.

Under their favourable economic-growth scenario, the *Main Provisions* project an increase in electricity output of 34% by 2010 (to 1,180 TWh) and of 84% by 2020 (to 1,620 TWh) compared with 2000. If this projection is accurate, output will exceed the pre-transition amount by 2010. In the less favourable scenario, production goes to 1,055 TWh by 2010 and 1,240 TWh by 2020, reaching pre-crisis levels around 2012. Both outlooks assume progress in energy efficiency on both the supply and demand sides, including price reform.

Generating Capacity

Generating capacity remained relatively constant over the 1990s. As of the beginning of 2001, total installed capacity in the Russian Federation was 214 GW, of which 69% was thermal, 21% hydro and 10% nuclear. By the beginning of 2000, Russia had over 500 thermal power plants, over 90 hydro plants and 29 commercial nuclear reactors (see Map 9 and Map 10). The electricity network is linked by almost 2.7 million km of transmission and distribution lines, including over 150,000 km of high-voltage lines of between 220 and 1,150 kW.

About 190 GW of total installed capacity is considered operational, with 175 GW available to meet base demand. Current system peaks are about 145 GW. The average utilisation level in 1998 was 44%. RAO UES estimated idle capacity at about 30 GW in 1999. This relatively low availability rate stems from inadequate maintenance and lack of investment in the 1990s.[134] About 40% of installed capacity has been in service for over 25 years. Table 8.7 reflects the paucity of data on the average age of the sector's capital stock. The lower-range estimates are from RAO UES. The estimates which reflect a much older capital stock provided by Russian energy experts are based on the fact that most of the electricity network and infrastructure was in place much before 1975.

Table 8.7 Average Age of UES's Electricity Fixed Assets in 1999

	Age	Planned Operational Life	Remaining
Generation (heat and electricity)	24-40	50	10-26
Electricity transmission	24-40	40	0-16
Electricity distribution	22-40	40	0-18
Heating networks	14-40	25	0-11

Source: based on information from RAO UES.

To match the high electricity consumption envisaged by the Energy Strategy for 2000-2020, the Russian government foresees the need to increase generating capacity 14% over 2000 levels by 2010 and 54% by 2020. These estimates and the timing of new-capacity installation depend on the ability to modernise and extend the lives of existing plants and to meet required technological and safety standards. Taking these factors into account, some Russian energy experts estimate that only a 10% increase over 2000 levels is possible to realise by 2010 and only a further 30% by 2020. About 35 GW of capacity will arrive at the end of its design life by 2005, and a further 30 GW by 2010. The Ministry of Atomic Energy has incorporated into its strategy the need to modernise and extend the lifetime of units from 30 years to 40 years for first-generation plants (6 GW), and up to 50 years for second and third-generation plants (15 GW). RAO UES is drafting analogous plans for upgrading and extending the lifetime of thermal power plants.

The *Main Provisions* project a nearly complete replacement of the most inefficient generating capacity with new, highly efficient equipment. An ambitious commissioning schedule would introduce 15 GW a year from 2011 to 2015 and up to 20 GW a year from 2016 to 2020, including from 0.6 to 2.2 GW a year of new nuclear generation capacity.[135] Some Russian energy experts cast doubt on what they consider an excessive rate of new capacity building, estimating that no more than 6 GW a year from 2011 to 2015 and up to 10 GW a year from 2016 to 2020 will be possible to introduce. The emphasis would be on NPPs, ecologically acceptable coal stations and CCGT, with the consumption of natural gas expected to remain below 1990 levels till 2020. The *Main Provisions* also call for reconstruction of existing capacity. The goal is to raise efficiency rates to 55% and eventually to 60%.

134. The reliability of these estimates is put into question by reports that the average age of existing capital stock was about 24 years in 1999 combined with the low level of maintenance and investment over the 1990s.
135. Any delay in this scheduling would result in lower fuel efficiency and hence higher fuel consumption than envisioned in the *Main Provisions*, which foresee total demand by Russia's power stations in organic fuel growing from 273 Million tonnes of fuel equivalent in 2000 to 310-350 M tce in 2010 and 330-400 tce in 2020.

The *Main Provisions* also emphasise the need to increase transmission between different regions and systems, a programme requiring considerable reconstruction and technical re-equipment of network facilities, as well as the construction of new lines. The envisaged commissioning of new lines of 330 kV and higher would bring the total to 25,000 km – 35,000 km by 2020. The *Strategy* specifically calls for:

- creation of a reliable interconnection between the Eastern and European parts of Russia through construction of 500-kV and 1150-kV DC lines. These lines could significantly reduce the need to transport coal from eastern Russia;
- creation of better transmission connections between the Middle Volga, Central and Northern Caucasus systems, which would improve the reliability of supply in the Northern Caucasus and allow the absorption of surplus capacity from the Tyumen region within the Siberian system;
- strengthening of interconnections between the North West and Central systems; and
- development of an interconnection between the Siberia and Far East systems, which would help improve the reliability of the system as a whole as well as guarantee the energy supply to the deficit areas of the Far East.

►►► ***The economics of extremely long interconnections should be rigorously tested.*** *Although investments in inter-regional systems could improve reliability, the economics of extremely long interconnections need careful examination before major investments are made. Electricity interconnection over very long distances is not the practice in most IEA countries. In Australia, for example, some states are not interconnected to the national grid.*

The *Main Provisions* present specific plans for plant construction through 2020. These include new coal-fired plants, retrofitting of gas-fired plants, the commissioning of four nuclear plants and the construction of transmission lines. Furthermore, 10 GW of NPP capacity, 5 GW of thermal power plant capacity and 6 GW of hydro-electric-power capacity are planned through completion of construction at various sites.

Limiting Factors in Realizing Electricity Generation Goals from Now to 2020

The government's plans for new capacity raise a number of questions, above all that of the sector's ability to attract the necessary investment funds. In addition to environmental concerns related to increased coal-based emissions, there are nuclear safety issues and economic questions relating to the large distances over which coal or electricity must be transported. Further difficulties involve the problems of the coal sector in attracting investment to increase production at profitable mines, as well as the cost of closing uneconomic mines and of providing social support systems for redundant miners.

As in many countries, problems of public acceptance and funding could affect plans to increase nuclear generating capacity. Meeting new safety standards could pose additional problems, given the strict enforcement of standards by the nuclear regulator, GosAtomNadzor (GAN). There are also concerns about attracting enough qualified personnel, at the low salaries being offered.

Comparative Economics

The *Main Provisions* do not include any assessment of the comparative economics of gas-fired and coal-fired generation, or that of NPP generation. The issue of reducing the share of gas in the fuel mix for power and heat generation is discussed mostly in the context of energy security and future problems of developing new gas supplies.

A key priority of the *Main Provisions* is the removal of current price distortions through price and tax policies, which would cause energy prices to rise, especially the prices of gas and electricity. The scheme calls for gas prices to increase some 250% by 2003 and a further 140% by 2005 without taking into account inflation. It sees domestic gas prices on a par with those in Europe by 2007. This would entail an increase of approximately 370%-400% over prevailing prices at the end of 2000. If these goals for gas price increases are not met, the outlook warns of lower gas production, especially in the first ten years, requiring even more dramatic changes to the fuel mix than currently considered necessary to balance the projected gas deficit.

The *Main Provisions* call for a realignment of gas and coal prices such that gas will become more expensive than coal over time. By 2005, they project the domestic price ratio between steam coal and natural gas to be about 1:1.2, increasing later to about 1:1.6-1.8, making natural gas almost twice as expensive as coal on a per-calorie basis. As a result, electricity prices would increase by 160% to 170% by 2003 and a further 160% by 2005. By 2010, projected prices will exceed current prices by 330% to 350%. These very ambitious price increases have gathered little support within the Ministry of Economic Development and Trade, which favours keeping prices low on the whole.[136]

►►► ***Impact of higher prices on demand.*** *Careful consideration is needed to assess whether future electricity consumption will require as much new capacity as now projected, in view of the dampening effect of higher prices on demand, if these ambitious price increases are realized. Moreover, it would be wise not to base assumptions about future demand elasticities on past Russian experience, which was complicated by non-payment problems.*

Investment decisions should be based on a calculation of full costs, including market-based prices for input fuels. Retrofitting existing plants will usually be the most cost-effective solution, although equipping plants with clean coal technology will *increase* costs significantly. For new plants, a 1998 study of generation costs[137] indicates that, under generic assumptions, nuclear plants are the cheapest solution assuming a discount rate of 5%, while gas-fired plants are cheapest using a 10% discount rate (see Tables 8.8 and 8.9). The choice will depend on a number of economic assumptions, including the costs of investment, operation, maintenance and fuels, as well as discount rates.

►►► ***Comparative economics of gas-fired versus coal-fired generation.*** *The substitution of coal for natural gas in existing or new power plants should be based on economic justifications, taking into account likely future fuel prices as well as coal and/or electricity transportation costs. Consideration should also be given to environmental aspects of such decisions, as well as the financial impact that they could have on the relative economics of different projects.*

136. For details on the "Short to Medium term Outlook" of the MEDT, see www.economy.gov.ru
137. NEA/IEA (1998), *Projected costs of Generating Electricity, Update 1998*, Paris.

Table 8.8 Projected Generation Costs in Russia (1996 US $/MWh)

	Coal				Gas				Nuclear			
Discount rate	**Capital costs**	**Operating/ maintenance**	**Fuel**	**Total**	**Capital costs**	**O / M**	**Fuel**	**Total**	**Capital costs**	**O / M**	**Fuel**	**Total**
5%	12.59	7.72	26.01	46.32	6.84	4.19	24.38	35.41	18.85	4.45	3.58	**26.88**
10%	24.31	7.35	23.68	55.34	12.85	4.05	22.09	**38.99**	37.17	4.5	4.85	46.52

Source: NEA/IEA (1998).

Table 8.9 Russian Fuel Price Assumptions (1996 US $ / GJ at the Power Plant)

	2005	2015	2025	2035	2045
Coal	2.01	2.50	3.05	3.72	4.53
Gas	2.68	3.48	4.24	5.17	6.30

Source: NEA/IEA (1998).

Comparative Economics of Renewables

Hydroelectricity is the major source of renewable energy in Russia, accounting for 19% of generation. A very small amount of electricity comes from geothermal energy. UES has commissioned a number of wind turbines as well as a 400-kW tidal power plant at Kislogub. Biomass is not widely used in Russia, either directly or for electricity generation. In general, efforts to develop renewable energy *diminished* in the 1990s due to a lack of financing. The *Main Provisions* foresee that renewables (excluding hydro) will account for only 1% of total electricity production by 2020. Higher electricity prices that cover all costs of input fuels may provide more opportunities for the development of renewable energies, however, as the cost gap between renewable and conventional fuels is reduced.

►►► ***Competitiveness of Renewables.*** *Several large IEA countries such as Canada and Australia have developed renewable energies on a commercial basis for remote, off-grid communities. Regional governments should assess the feasibility of renewable energies in analogous remote regions of Russia. The economics of renewable energy development will improve if competing conventional energy forms are priced at their full costs, including applicable taxes or other charges for pollution.*

Energy-Efficiency Improvements

Russia's economic growth depends not only on its vast natural resources but also on more energy-efficient use of those resources, in heating systems, companies, buildings, houses and transport. Without such improvements, the Russian energy sector risks hampering overall economic growth, with energy security also at risk in remote regions that are already experiencing fuel shortages. In view of the dampening effect of planned higher prices on demand, it is important to assess whether future electricity consumption will require as much new capacity as now projected. In the Russian context, assessing future demand elasticities is complicated by past non-payment problems.

UES has started an energy-saving programme in generation, transmission and distribution. UES estimates that with little or no additional investment a total of one Mtoe per year has already been saved and that a further five Mtoe per year could be saved under similar conditions. A total of 18-20 Mtoe could be saved between 1999 and 2010 through market-based investments.

►►► ***Energy-Efficiency Improvements.*** *Comparative cost assessments should be made among the various options. Supply-side options should be compared to demand-side solutions. Higher electricity tariffs would make it possible to design more realistic demand-side energy-efficiency programmes.*

Research and Development

R&D efforts are increasing in the electricity sector as utilities seek to improve the efficiency of existing plants and replace obsolete technology. The main activities are:

- research by UES to allow serial production of high-power gas-turbine units, (in which a new design of turbine was successfully tested in 1999);
- research on environmentally friendly and economically efficient technologies for fossil-fuel combustion under the Federal Fuel and Energy Programme, with specific attention to supercritical coal-fired power plants;
- research to improve the reliability, economic efficiency and safety of existing power plants and extend their operating life;
- continuing Russo-Japanese co-operation to modernise Russia's fossil-fuel power plants, with the main objective being to reduce carbon emissions;
- research to improve the efficiency of electricity transmission;
- research in nuclear power generation.

►►► ***R&D Investments.*** *Given limited financial resources, advantage should be taken of existing opportunities for international co-operation in R&D, such as the IEA Implementing Agreements. Such co-operation can save resources and help avoid international duplication of work.*

Ability to Attract Necessary Investment

In the 1990s, UES investment policy focused on re-equipping and reconstructing existing capacity. Although capital investments by UES increased in nominal terms throughout the 1990s, in real terms they dropped to about one-third of what they were in the early 1990s. With the economic turnaround since 1999, the electricity sector needs major investments to refurbish and increase capacity by 2010 and beyond to 2020. The Russian Energy Strategy projections of investment needs (Table 8.10) reflect a significant ramp up in investments in the period after 2011, attributed mainly to the increased needs of the thermal power sector. Ministry of Energy estimates investment needs at about $4 billion a year through 2005, increasing to $5 to $8 billion a year to 2010. During the period from 2011 to 2015, annual investment needs jump to average $9 to $14 billion and reach as much as $12 to $17 during the period from 2016 to 2020. The *Main Provisions* call for some 15-20 GW to be commissioned annually, meaning a cost of about $1 million per Gigawatt, which is low by OECD standards. It is not clear how these estimates take into account the demand-side management potential to reduce the need for new supply-side investments.

Possible financial sources for major investment include state financing, internal funding, equity investment and debt financing. State help will likely be minimal (up to 5%), given budgetary constraints. Although internal company funds raised through higher electricity tariffs and increased payment collections would help, their scope is limited.

Table 8.10 Projected Investments in the Russian Electricity Sector, 2000-2020 ($ Billion)

Investments	2000	2001-2005	2006-2010	2011-2015	2016-2020	Total
NPP	0.4	4-5	6-9	6-11	7-9	23-34
Hydro-electric power	0.3	3	5	5-6	6-9	19-21
Thermal power	0.5	7	8-19	24-38	36-54	75-118
Transmission network	0.4	4	6-9	9-14	12-17	30-43
Total	**1.6**	**18-19**	**25-42**	**44-69**	**61-87**	**147-217**

Source: "Energy Strategy of the Russian Federation to 2020", MinEnergo, 2001.

The last two options would require some corporate restructuring and tariff reform, as well as improvements in corporate practices and the protection of shareholder rights. Joint Implementation (JI) projects under the Kyoto Protocol to reduce greenhouse gas emissions may be another source of funds. Feasibility studies by Japanese investors are already underway to upgrade electric power stations in the Far East.

Another mechanism to attract direct investment is via "energy service companies" (ESCOs). This mechanism helps companies reduce their energy consumption in exchange for a portion of the cost of energy saved. The feasibility of such schemes should improve with higher electricity tariffs and bill-collection rates.

In general, however, the poor investment climate in Russia will continue to hinder foreign direct investment. The current investment environment is characterised by fiscal, legal and regulatory instability and a great lack of transparency. In this respect, the general economic reforms outlined in the "Economic Development Plan to 2010" by the Ministry of Economic Development and Trade are encouraging. Also encouraging are statements by the Ministry of Economics and Trade that the government intends to pay greater attention to reform of the electricity sector.

►►► ***Attracting Outside Investment.*** *A range of macro- and micro-level reforms will be needed to make investment in the electricity sector competitive with other investment opportunities within Russia and internationally. These include raising electricity tariffs to cover full long-run costs, removing cross-subsidies and solving the problem of collecting non-cash payments. Measures to increase the transparency of company finances and other aspects of corporate practice are also important, as are efforts to increase the independence of regulatory bodies at both the federal and regional levels.*

FUNCTIONING OF THE RUSSIAN ELECTRICITY MARKET TO 2000

Functioning of the Russian Electricity Market

The Russian electricity sector is vertically integrated, with no competition at the wholesale level and no choice of supply for consumers. The entry of new generators would be very difficult under the current structure, which is marked by the overwhelming presence of UES as owner of both the grid and of most of the main generators.

►►► ***Separating Generation and Transmission.*** *The national transmission function should be separated from generation to avoid giving the owner of a transmission line an incentive to favour its own generating units. As experience in a number of IEA countries has shown, such a separation does not necessarily require separate ownership, but it does require a clear institutional division in order to promote unbiased decision-making by the grid operator.*

The Federal Wholesale Market, known as FOREM, was designed to redistribute surplus electricity and generation capacity (Table 8.11). The sellers on the market are nuclear power stations, UES power plants and regional utilities (*energos*) enjoying a surplus, while the buyers are *energos* in deficit and large industrial consumers. By 1999, the FOREM had grown to about 130 participants, including 13 large electricity consumers,[138] 13 *energos* with capacity surpluses, 53 *energos* with capacity deficits, and 25 large power plants. Most electricity imports and exports also go through the wholesale market. In general, there is over-capacity in the western regions, where demand fell the most during the 1990s, while constraints on electricity supply exist in most other parts of the country.

Table 8.11 Federal Wholesale Electricity Market

	1993	1994	1995	1996	1997	1998	1999	2000
Turnover TWh	296	266	279	272	272	266	282	293
% of Russian production	32	31	33	32	33	32	38	38

Source: http://www.rao-ees.ru

The original plan for the wholesale market was to introduce inter-utility competition. It was considered essential to remove the dispatching function from UES to ensure non-discrimination. This did not happen. Although the FEC was established as a regulator, its main function in the electricity sector has been to control electricity tariffs. It does not set rules for the federal wholesale market. UES regulates the FOREM itself and guarantees power supply to consumers throughout Russia. It has charge of electricity dispatch through its wholly-owned subsidiary, the Central Dispatch Unit (CDU), and seven Regional Dispatch Boards.

A type of "merit order" dispatch is negotiated quarterly among the central dispatch unit, the plants of the different *energos* and *RosEnergoAtom*. The *energos* inform the CDU of their needs, and this leads to negotiations in which the ultimate decision is taken by the CDU. Because the CDU is a wholly owned subsidiary of UES, the objectivity of the merit-order process would appear limited, leaving open the possibility for dispatching decisions based on political, social or monopolist considerations. For example, it has been noted that "no competition between different suppliers is possible" in the Russian system. Sales outside this "market" are also impossible, because electricity consumers may not enter into direct contractual relationships with suppliers.[139]

138. An individual electricity consumer needs permission from a Regional Energy Commission (REC) to participate in the FOREM
139. Opitz, Petra (2000), "The (Pseudo-) Liberalization of Russia's Power Sector: the Hidden Rationality of Transformation", *Energy Policy* 28, pp. 147-155.

The vertically integrated structure of UES therefore would seem to be a barrier for new entrants into generation. As elaborated in *Competition in Electricity Markets* (IEA, 2001), a transmission-grid owner which also owns generation assets will tend to discriminate against other generators while favouring its own. To the extent that competing generators must use the network to deliver their electricity, the transmission owner can also discriminate among them. It does this by setting high access prices, by reserving transmission capacity for its own generation units, by providing unequal access to technical information or by imposing unnecessarily high technical requirements. Further, the network owner may enter into long-term contracts that block transmission capacity.

In the Russian electricity sector, higher-cost co-generation plants generally come first in the "merit order", the aim being to allow them to supply heat to their customers. Their electricity is effectively treated as a by-product of heat production. Most of these plants are owned by the *energos*. Next in the merit order are UES-owned plants, followed by nuclear power plants.[140] UES-owned power plants currently operate on average at 39% of capacity, while those of the regional *energos* operate at closer to 50% of capacity and NPPs at 70%.

As shown in Table 8.12, electricity generated by nuclear and hydro plants is offered at prices much lower than that generated by UES thermal plants, and hydro-generated electricity is offered at prices much lower than the average selling price on the FOREM. This effectively results in cross-subsidisation of less competitive UES thermal plants by cheaper hydro and nuclear plants. In this respect, the pricing system on the FOREM would seem to result in an economically irrational use of generation assets. Regional power companies which do not produce enough electricity to meet demand tend to over stretch their own uneconomic power sources rather than buy electricity from FOREM. Meantime, suppliers with *efficient* generating capacity find it more profitable to sell electricity outside FOREM.

Table 8.12 Structure of FOREM Purchasing and Selling Prices (Roubles per 1000 kWh)

	1998	1999	2000	Share of FOREM Sales (%) in 2000
Purchasing prices				
– Thermal power plants	188.7	205.9	268.7	30
– Hydropower plants	36.8	47.8	52.8	22
– Nuclear power plants	153.6	158.4	214.8	41
– Energos with surplus output	133.2	151.8	174.3	7
Average recommended selling price	134.9	147.2	192.8	

Source: http://www.rao-ees.ru

►►► ***Transparent, cost-reflective pricing on the electricity wholesale market.*** *If the government intends to minimise costs in the wholesale provision of electricity, it should ensure that the bidding system is transparent and that it limits chances for discrimination. An important precondition to doing this would be to make the CDU institutionally independent from UES.*

140. In 1998 *RosEnergoAtom* accused UES of imposing restrictions on nuclear power output to favour non-nuclear producers. *East European Energy Report*, Financial Times, 1998

The Importance of Independent Regulation

The Federal Energy Commission (FEC) was established in 1995 with a mandate to regulate all natural monopolies.[141] In the electricity sector it is responsible for:

- setting the *maximum* wholesale prices for UES-owned fossil-fuel and hydropower plants, nuclear power plants and *energos*, as well as recommended selling price for sales on the FOREM;
- setting charges for services provided by UES in the FOREM;
- setting tariffs for the use of the UES transmission grid; *energos* and *RosEnergoAtom* pay a fee to UES for the use of the grid; fees are set by the FEC on a cost-plus basis, including costs of grid maintenance, administrative costs, depreciation and dividends;
- setting purchase prices for electricity from nuclear plants, with the aim of including all costs of supply, including investment costs;
- developing long-term investment priorities for the industry;
- supervising the RECs; the FEC sets an indicative range of consumer tariffs for each region; it also approves the nominations of the management of the RECs, monitors the decisions of the RECs and ensures their legality.

The independence of regulatory bodies is of utmost importance to ensure that tariffs are set at levels that cover all costs and to preserve the sector's attractiveness for investors. The RECs have charge of regulatory issues at the regional level and of setting consumer tariffs for electricity and heat, within guidelines and boundaries set by the FEC. Although they are established as independent regulators, their independence from regional administrations is not always perfect. Until recently, regional governments appointed most regional regulators. Although the FEC nominally had the power to reject nominees of the local governments, in practice it usually approved them. Moreover, budgets for most RECs passed through their regional administrations. Many RECs have faced local political pressure to keep tariffs below those recommended by the FEC. The power supply crisis in the Primorsk region in the winter 2000-2001, underscores the dangers regions run in doing so. In 1999 only about half of the RECs had approved tariffs that were above the minimum recommended by the FEC. According to the FEC, the situation appears to be improving. By the end of 2000, it declared that some 60 of the 80 RECs to be "independent" from their regional administrations.

►►► ***Lack of REC Independence.*** *Without independent regulation at the regional level, local governments will have an incentive to set tariffs at sub-optimal levels for political purposes. While such policies may serve the short-term needs of local populations and industry, they will not attract adequate investment capital and will harm consumers in the long run.*

The Need for Tariff Reform

Tariff reform continues to be a key issue. Over the period from 1991 to 2000, electricity prices rose only half as fast as industrial producer prices. Although the low prices kept inflationary pressures at bay, they damaged the sector and led to inefficient energy use. Furthermore, distortions exist due to cross-subsidies and non-payment.

141. The FEC was established by the *Law on State Regulation of Charges for Electricity and Heat Energy in the Russian Federation, 1995*. In 2001, it was announced that the FEC was to be replaced by a new unified regulatory body. But it appears that this new body will still be called the FEC although its responsibilities will be substantially increased.

Cross-Subsidies

The main features of tariffs to different consumer groups are as follows:

- high-voltage industrial consumers (over 500 kV) are the only group with tariffs that take into account capacity and consumption;
- industrial and commercial customers with capacities under 500 kV pay the higher rates;
- according to the FEC, prices for residential consumers should cover the full costs of supply, plus a 5% profit margin. In practice, this rarely happens. By law, households in the countryside should be charged a tariff 70% below the average household. RECs may also designate other categories of households for rebates.

►►► ***Need for a Transparent Methodology for Setting Electricity Tariffs.*** *Independent regulatory bodies need to be able to set tariffs using clearly defined and transparent methodology that will ensure that costs are covered.*

Table 8.13 shows the variability across regions of tariffs set by RECs in 1998. It also indicates a high level of cross-subsidisation of the residential sector. As indicated in Figure 17, electricity tariffs generally increased in 1996-1997, but with 1998 financial crisis and the devaluation of the rouble, tariffs dropped to all-time lows, a dramatic setback for electricity tariff reform. The gap between industrial and residential prices has actually widened since the rouble devaluation. Moreover, the situation in Russia contrasts sharply with that in most OECD countries, where residential tariffs tend to be much higher than industrial tariffs, reflecting the actual cost of supplying different types of customers.

Table 8.13 Electricity Prices in Selected Regions, 1998 (R/kWh)

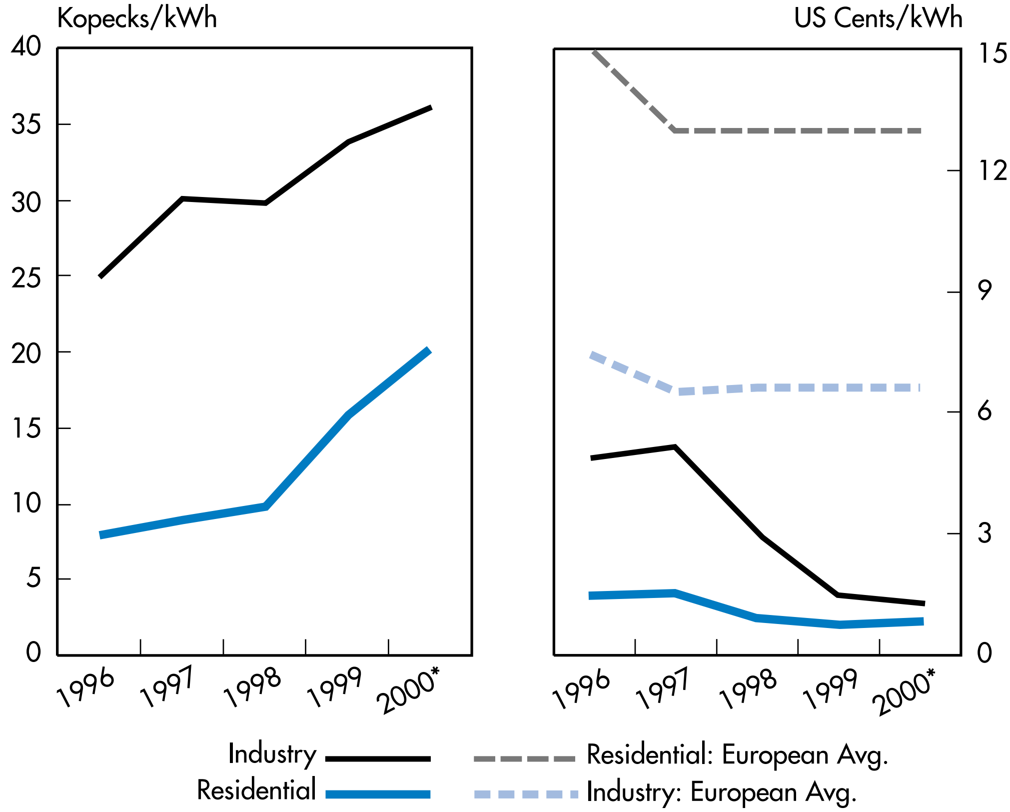
	Average	High-voltage Industry	Low-voltage Industry	Residential	Transport	Agriculture
KamchatkEnergo	0.786	1.36	1.50	0.24	n.a.	0.91
SakhalinEnergo	0.441	0.62	0.64	0.21	n.a.	0.56
DalEnergo	0.408	0.50	0.57	0.25	0.40	0.38
IrkutskEnergo	0.079	0.09	0.09	0.06	0.09	0.04
KrasnoyarskEnergo	0.109	0.11	0.25	0.07	0.11	0.08
KhakassEnergo	0.11	0.16	0.15	0.05	0.13	0.06

Source: RAO UES.

Nevertheless, current prospects for energy price reform would seem to be positive, with strong political support voiced for it throughout the government and the energy sector. From August 1998 to December 2000 the increase in electricity prices in the industrial and residential sector was 276% and 280%, respectively. Since May 2000, electricity and heat prices grew faster than industrial producer prices. UES has stated that it plans to end such cross-subsidisation by 2002.

►►► ***Electricity Cross-subsidies.*** *The Russian government plan to end cross-subsidies by 2002 should be commended and its implementation strongly encouraged. Welfare assistance targeted to the most vulnerable sectors of society will be more effective and economically more efficient than energy-price subsidies.*

Figure 17 Comparison of Residential and Industrial Electricity Tariffs, 1996 to 2000 (in Kopecks and US cents)



* First half only.

Creation of a Small Parallel Market

In 1999 settlements for electricity supplies in FOREM reached 98%, an increase of about 10% over 1998. Cash payments still represented only about 17% of settlements, however. Although this was more than double 1998, the low volume of monetary settlements would seem to have hampered FOREM's efficiency. Because *energos* with surplus are less willing to supply electricity to non-paying customers, FOREM has seen smaller trading volumes, inefficient use of generation capacities and higher generation costs. Low cash payments from 1995 to 1999 had the obvious effect of reducing companies' ability to reinvest as well as to pay for fuel inputs and salaries. This contributed to many interruptions in electricity and heat supply.[142] The non-payment issue also provided strong incentives for electricity suppliers to establish direct sales contracts with liquid consumers.

UES effectively encouraged this parallel market by providing grid access to liquid customers in exchange for cash payments – in effect a kind of negotiated third-party access. At the end of 1998, an agreement reached with RAO UES allowed *RosEnergoAtom*

142. One of the most notable instances of this took place in the far-eastern district of Primorye, where 80,000 residents of several cities were without heat from autumn 2000 into the winter months of 2001.

to enter into direct contracts with customers. But, the parallel market has remained small, given the limited number of liquid customers. By contrast, supplies through FOREM accounted for about 31% of total supplies in 1993, the year of its inception, and about 38% in 1999.

Issues of corporate practices and transparency emerged as the parallel market stimulated what amounted to upstream and downstream mergers between generators and their main cash-earning customers or suppliers. Beginning in 1998, UES created a number of integrated fuel-power companies (*LuTEK*, *UralTEK*, *BurTEK* and the Kuzbass Power Co.), in which coal mines combined with the electricity plants that they supplied. Similar mergers were made between energos and aluminium companies. However, in some cases concerns about transparency have raised much concern among UES shareholders.

►►► ***Transparency, independent appraisals of the properties for sale and competitive tenders are essential.*** *Restructuring of RAO UES generation and distribution assets needs to be carried out in a transparent way, with independent appraisals of the properties for sale and competitive tenders. Even if RAO UES management considers certain actions to bring much-needed efficiency to the industry, shareholders need to be reassured that transactions are undertaken transparently with independent audits and appraisals.*

Improved Cash Collection

Low cash payment from 1995 to 1999 was one of the main factors hampering the Russian electricity sector. UES began cutting off non-paying customers in July 2000. The company reports that the year 2000 as a whole, settlements came to 105%. This was an improvement of 5% over 1999. However, according to GoskomStat, payments for current energy deliveries, excluding repayment of past debts, amounted to only 85% in 2000. The share of cash payments increased from 35% in 1999 to 83% in 2000. Starting 1 January 2001 all non-cash settlements were prohibited. UES announced that cash payments during the first quarter of 2001 represented 92% of the total due, a promising sign that UES has managed to maintain its collections even in winter, when the heating component in total payments is high.

Since many of the largest non-payers have been state bodies, a major part of the solution to the non-payment problem would seem to rest in the hands of federal and local governments. It was therefore welcome news that the federal government increased the budgets of administrations in 2000 to allow them to pay their energy bills. Administrations are to receive specific funds for each category of expenditure, with their use monitored and controlled.

In 2000 UES used various methods to improve the level of payment collections, including:

- disconnection of non-payers;
- establishment of a system of prepayments and the use of letters of credit;
- introduction of limits on deliveries to state organisations;
- tightening of controls over electricity consumption by public-sector consumers.

UES has little choice but to toughen its position against non-paying customers, since Gazprom demanded 100% payment from UES for gas deliveries in the first quarter of 2000. This heightened tensions between Gazprom and UES, although gas deliveries were maintained with only slight reductions (compared to the cuts threatened by Gazprom at the time), due to presidential pressure on Gazprom. But lower gas deliveries, obliged UES to resort to more expensive heavy fuel oil and coal to make up the difference. The hard budget constraints imposed on UES by Gazprom forced UES to impose those same constraints on its customers. The results have been impressive.

►►► ***Improvement should continue in dealing with the non-payment problem.*** *The increase in payments, especially cash payments, has been impressive since serious collection efforts began in 2000. If tariff levels increase as planned, it will be necessary to maintain this effort to avoid falling back into the vicious cycle of non-payment.*

Although there have been improvements in collections, accumulated inter-company and sectoral debt remain very large. The outstanding debt owed to UES was estimated in June 2000 at almost 150 billion Roubles (over $5 billion), while outstanding debt owed to Gazprom by its domestic customers was estimated at over 100 billion Roubles. The most important single debtor to Gazprom is RAO UES, reportedly reaching almost $1.5 Billion in early 2000. The biggest debtor to both Gazprom and UES is the Russian State, including regional governments and budget-funded organisations at all levels.

►►► ***Outstanding debts need to be paid.*** *The large overhang of inter-company and sectoral debt between energy producers and consumers continues to throttle investment by companies and to limit private investment.*

Tariff Reform and the Financial Situation of UES and the Energos

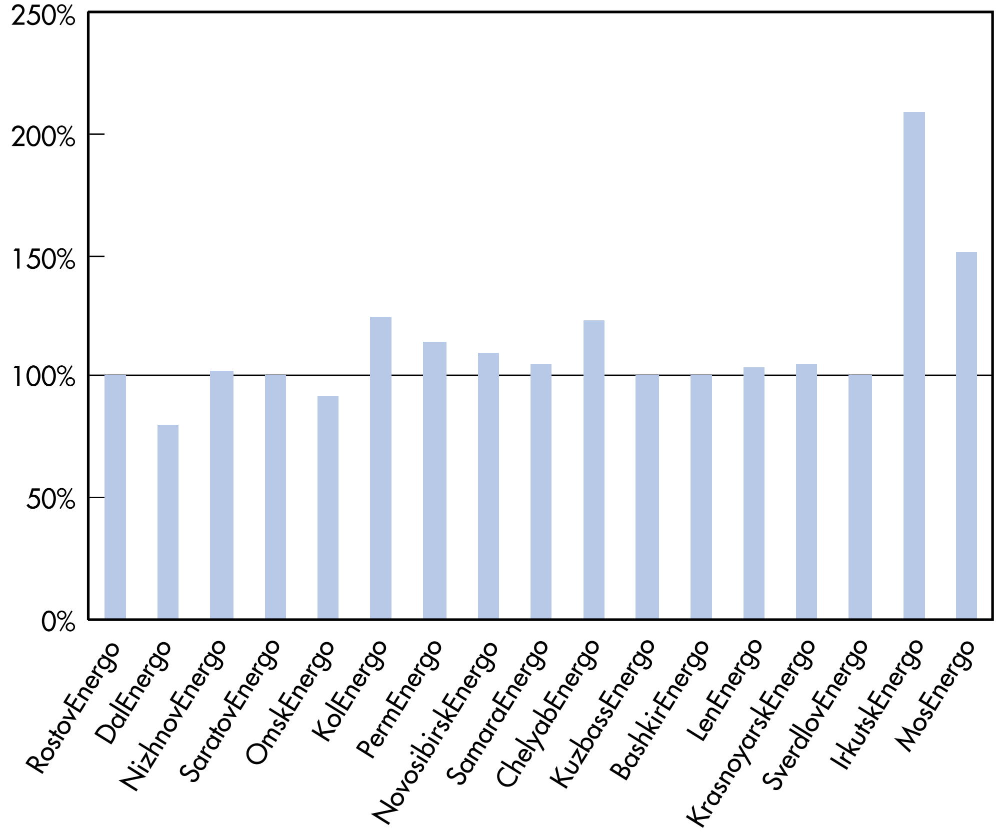
Electricity tariff reform was one of the IEA's main recommendations in 1995 and continues to be one of the critical elements in Russia's Energy Strategy to 2020. Without an increase in electricity tariffs, such that all costs are covered, plus a return on investment, companies will not be able to reinvest in maintaining and increasing generating capacity, and the sector will remain unattractive to investors.

Figure 18, based on information from UES, provides a comparison between the average tariffs charged to residential and industrial consumers and production costs of various *energos* across Russia in mid-2000. The average tariff structure in 1999 comprised labour costs (8%), fuel costs (25%) and "other expenses" (49%), with only 6% left to cover depreciation and a 12% profit.[143] The figure shows how average tariffs charged by *energos* barely cover costs. There are exceptions, however, like IrkutskEnergo, whose production is based on hydropower, and whose tariffs more than cover costs.

The Russian Energy Strategy forecasts Russian electricity prices to increase by over 160% in real terms by 2003, and a further 160% by 2005. By 2010, expected prices will reach some 330% of the level at the end of 2000, and perhaps as high as 350%. If these price reforms are implemented effectively, Russian electricity prices would cover long-term costs, providing for adequate maintenance and repair as well as needed retrofits and new capacity.

143. Russian accounting practice effectively treats profit margins as a cost. Russian companies generally do not view such profits as money available for reinvestment, but for distribution to employees and shareholders.

Figure 18 Average Tariffs vs. Prime Costs (%) in Mid-2000



►►► ***Electricity prices need to cover the full cost of supply (operating and capital costs).*** *To allow for sufficient maintenance and the upgrading of existing capacity, as well as investments in new capacity, electricity tariffs need to cover all costs, not just those for fuel. In the past, electricity prices have not kept pace with inflation. While this reduced inflationary pressures and provided cheap electricity for industry, these benefits came at the expense of the long-term sustainability of electricity supply.*

Although electricity tariffs increased 33% in May 2000, UES estimated that this would not even be enough to cover the increase in fuel input costs for the year. It stressed the need for yet another tariff increase on the order of 35%-50% for thermal plants, just to cover short-term costs, while increases of 12% to 24% would be required at hydropower plants. Increases of 20% are estimated to be needed for NPPs to cover investment and modernization needs. Investment needs far exceed funds available within the electricity sector at current tariff levels.

ELECTRICITY SECTOR RESTRUCTURING: PLANS AND OUTLOOK

A three-stage restructuring plan for the electricity sector was finally approved on 11 July 2001, concluding months of debate. Under the plan, generating firms belonging to RAO UES will be reorganised into independent companies. A state transmission company will be formed to handle the high-voltage grid only. The regional *energos* will remain intact, but will be obliged to create separate companies for generation and distribution either by creating subsidiary transmission companies or breaking themselves into separate generation and distribution-supply components. *Energos* will maintain their status as "guaranteeing suppliers," obliged to serve customers at regulated prices. A wholesale market will be built up in regions with potential multiple suppliers. These may include generating firms separated from RAO UES, nuclear generating companies, generating firms within regional *energos*, and new entrants. All companies are to be guaranteed non-discriminatory access to the high- and low-voltage grids.

In the first stage of reform, from 2001 to 2004, generating firms not separated from RAO UES, *energos*, or the MinAtom will be free to sell only 5-15% of their output on the wholesale market at free prices. Their remaining output will be supplied at regulated prices. The share of the wholesale market in overall electricity production will increase gradually along with competition. In the first stage, retail prices will remain regulated, although tied to wholesale prices. In the second stage, from 2004 to 2006, independent suppliers will be free to enter the market, will receive non-discriminatory access to the grid, and will have the ability to contract directly with generating firms and final consumers. The programme also envisions gradual elimination of cross subsidies, an increase in consumer prices sufficient to cover investment costs, and special measures to help poorer segments of the population.

The *energos* will control the regional low-voltage networks, in addition to generating firms and supply functions. They will, therefore, continue to be local monopolies. In other countries, establishing genuine non-discriminatory access to the network has proven very difficult under such circumstances. To ensure such access, the government would need to monitor not only price, but a number of other variables, such as quality of service and transfer pricing schemes. Decisions on wholesale and retail price deregulation are also sure to be unavoidably complicated by the continued presence of monopoly power. Various schemes for transfer pricing and for shifting assets among different parts of one company will also hold up progress. The strong involvement of regional administrations in many regional *energos* could exacerbate this by opposing the purchase of potentially cheaper electricity through the high-voltage grid.

Despite the concerns raised above, the proposed restructuring plan is in line with the approach of many OECD countries for unbundling the electricity sector (see box). Key to the plan's success and the viability of the restructured companies will be effective implementation of planned increases in electricity tariffs to levels that cover all costs – and enforcement of payments.

Electricity Sector Restructuring in IEA Countries

A review of national approaches to electricity-sector restructuring in IEA member countries provides a context for developments in Russia. The emerging alternative to the vertically integrated monopoly is the "retail competition model", which includes the following characteristics:

- transactions between generators, end users and other intermediaries, including retailers, power exchanges and/or brokers, take place within the technical constraints imposed by the grid;
- transmission prices are regulated and non-discriminatory third-party access to the network is ensured;
- there is an independent system operator, who is, not controlled by the owners of generation assets.

This model is the starting point for the electricity markets in Finland, Norway, Spain, Sweden, and in some US states, and for the New Electricity Trading Arrangements in the UK.

Reform programmes in these markets have typically included:

- structural reforms designed to separate regulated activities from potentially competitive activities, and to promote competition within the latter;
- institutional reforms to provide framework conditions for the effective functioning of competitive markets and performance regulation to provide incentives for the efficient management of regulated activities.

For a more detailed discussion of restructuring in various IEA countries, see *Competition in Electricity Markets*, IEA (2001), Paris.

ELECTRICITY EXPORTS

Russia is a net exporter of electricity to both CIS countries and the "far abroad". In 1999, exports reached 22.5 TWh, accounting for 2.7% of Russian generation. From 1993 to 1998, net exports averaged 18-20 TWh per year, with two-thirds directed to CIS countries. In 1999, exports to Ukraine and Kazakhstan, two of Russia's largest CIS customers, were reduced significantly due to non-payment. Electricity exports to the "far abroad" have been maintained and in some cases increased.

Table 8.14 Net Electricity Exports (TWh)

	1993	1994	1995	1996	1997	1998	1999
Europe	4.7	5.1	5.3	5.2	5.2	5.0	5.2
CIS	13.8	14.8	14.3	15.1	12.8	13.1	8.8
Baltics	– 0.1	0.2	– 0.1	– 0.9	– 1.9	– 0.5	– 0.1
Other	0.2	0.4	0.1	0.2	3.7	0.4	0.3
Total	18.7	20.5	19.6	19.5	19.7	18.0	14.2

Source: IEA estimates; Fuel & Energy of Russia, A. M. Mastepanov, Ministry of Energy, 2000.

Table 8.14 illustrates the decrease in net exports to Russia's neighbours, and Table 8.15 gives details on payment and non-payment. In 1999, exports to Ukraine, Georgia and Kazakhstan were cut to the amount actually paid for, and in early 1999 commercial deliveries to Ukraine practically halted. Negotiations on scheduling and repayment of debts for past electricity exports are under way. As in the domestic market, substantial progress in debt collection came in 1999, following cut-offs to a number of CIS importing countries. From 1 January 2000 to 1 January 2001, outstanding debts to Russia were reduced significantly by Belarus ($40 to $22 million) and Ukraine ($84 to $55 million), while outstanding debts by Kazakhstan ($414 million) and Georgia ($46 million) remained.

Table 8.15 Payments to RAO UES for Electricity Exports, 1998 to 2000

	1998				1999				2000			
	Exports		Paid in 1998		Exports		Paid in 1999		Exports		Paid in 2000	
	TWh	$US Mln	Total	In Cash	TWh	$US Mln	Total	In Cash	TWh	$US Mln	Total	In Cash
Ukraine	3.1	84	9	1	0	0	21*	1	0	0	17*	0.2
Kazakhstan	2.6	64	30	18	2.1	41	46*	19	1.8	28	27	26
Belarus	5.0	121	67	0	5.8	122	136*	0	6.5	109	126*	15
Georgia	0.2	5	2	2	0.1	1	0.1	0.1	0.3	5	5	5
Total CIS States	**10.9**	**274**	**108**	**21**	**8.0**	**165**	**203***	**20**	**8.6**	**141**	**175***	**46**
Turkey	0.4	9	7	7	0	0	2	2	0	0	0	0
China									0.1	1.9	1.4	1.4
Latvia	0.1	1	1	1	0.2	4	3	2	0.3	7.2	7.4*	7
Poland									0.2	2.1	1.3	1.3
Finland	0.7	18	17	17	0.8	17	18*	18	3.9	60	60	60
Total Other	**1.1**	**28**	**26**	**26**	**1.0**	**21**	**24***	**22**	**4.5**	**71**	**70**	**70**
TOTAL	**12**	**302**	**134**	**47**	**9**	**186**	**227***	**42**	**13**	**212**	**245***	**115**

** Payments in monetary form exceed the energy supplied due to down payments of consumer receivables.*
Source: RAO UES.

Export Outlook

The increase of electricity exports has a high priority for Russia, as this is a major potential source of funds for financing operations and investments. Because an increase in exports to CIS countries is unlikely because of their insolvency, plans for expansion currently centre on markets beyond the FSU. UES plans to increase electricity exports to 35 TWh in 2010, a 55% increase over the 22.5 TWh of 1998. The *Main Provisions* project a further increase of between 40 and 75 TWh by 2020. In the short and medium term, these increases will go mainly to Western Europe. In 2000, the fourth unit of the Vyborg 350 MW transformer complex and the third St-Petersburg-Vyborg transmission line came into operation, increasing the reliability of transmission from Russia to Finland. The 600 MW contract with the Finnish companies *PVO* and *Fortum* was completed and the outlook is for this to increase to possibly 1,000 to 1,400 MW once a third 400 kV line is completed. A contract was signed y A new contract for 2001 was signed between RAO UES and the Norwegian company Norsk Hydro (200 MW). Several contracts completed at the beginning of 2000 cover supplies to Poland via Belarus, with electricity being re-exported from there to Germany. These were extended into 2001. Other contracts have been concluded with *RWE Energie* and *Bayernwerk* of Germany and *Verbund* of Austria.

The three main electricity systems in continental Europe are the Union for the Co-ordination of Transmission of Electricity (UCTE) (Belgium, Federal Republic of Yugoslavia, Germany, Former Yugoslav Republic of Macedonia, Spain, Luxembourg, France, The Netherlands, Greece, Austria, Italy, Portugal, Slovenia, Switzerland, Croatia, Bosnia-Herzegovina), CENTREL (Hungary, Poland, the Czech Republic and Slovakia) and the Russian UPS/IPS (Unified Power System/Integrated Power System). CENTREL was synchronised with UCTE in 1995. UPS/IPS is not synchronised with either of the other systems and has no direct AC connection with UCTE, although it does have a back-to-back DC link to the Scandinavian NORDEL grid at Vyborg, Finland.

A 2000-km, 500 kV DC line crossing Belarus, Lithuania, Kaliningrad and Poland to Germany is under consideration. Other projects include the so-called Baltic Ring and the Black Sea Interconnection (see box), as well as the modernisation of existing transmission lines to Central and Southeast Europe. Exports to Central and Western Europe are also being considered via the national grids of Belarus, Ukraine and Poland. This latter project would initially be on the order of 8.5 to 10 TWh a year, increasing to 14 to 16 TWh after investments of approximately $430 million.

In the longer term, a "power bridge" between Russia and Japan is under consideration. It would require the construction of an underwater cable with a transmission capacity of 4,000 MW from Sakhalin to the islands of Hokkaido and Honshu. A second envisaged "bridge" would extend from eastern Siberia to China. The cost-effectiveness of such links needs careful evaluation, taking into account the prospects for demand and prices to final consumers in the target markets.

The Baltic Ring

The Baltic Ring is a series of planned AC and DC interconnections, including submarine cable connections to Norway and Sweden, aimed at linking all the countries around the Baltic Sea in a common electricity market. There are almost 20 electricity companies involved in this project, which would connect Estonia, Latvia, Lithuania, Poland, Germany, Sweden, Finland, Russia and Belarus.

Black Sea Regional Interconnection

The Black Sea Economic Co-operation (BSEC) Working Group on Energy is undertaking a feasibility study to interconnect Black Sea littoral states. The project would include underwater links between Southeast Europe and the Caucasus. Two key countries, Bulgaria and Romania appear more interested in aligning themselves with UCTE (Union for the Co-ordination of Transmission of Electricity) and are already operating their networks in parallel with Greece.

Several western utilities are studying the possibility of importing Russian electricity into Germany and marketing it in the competitive European market. A study group made up of *PreussenElektra*, *VEAG*, the Polish Power Grid Company, the Belarussian electricity-company and UES is examining the possibility of upgrading the east-west transmission grid to send some 4,000 MW of power westward. The group found that a multi-terminal, high-voltage DC power line crossing Belarus and Poland to link Smolensk, Russia with Borken, Germany, could be economic. The need for this electricity still is not clear, as there is now over-capacity in Western Europe. Public resistance to new transmission lines is another issue. Any export scheme would have to ensure it priced Russian electricity to cover all costs, so as not to be accused of "dumping" under international trade rules.

The scale of potential Russian electricity exports remains an unsettled question. If electricity exports were feasible, the Energy Charter Transit Protocol offers the possibility of Russia's establishing, together with neighbouring transit states, a legal regime to protect electricity transit. This would reduce the uncertainty associated with access to transit facilities and the tariffs for their use. Also it would increase the use of existing Russian transit facilities and tap the potential of cross-border energy swaps. This point has special importance in Central Asia, where geography made such electricity transit necessary within the former Soviet Union. Today, the lack of legal certainty in the area hampers transit. The Protocol would reduce the likelihood that redundant transit facilities would be built. In addition Russia would benefit because there would be fewer disputes over transit issues. In the event one should arise, Russia would have recourse to the transparent international dispute-settlement mechanisms in the Transit Protocol. An avoidance of basing energy-structure decisions on political considerations will be in Russia's long-term interest as the major energy player in the region.

HEAT SECTOR

It is hard to separate the electricity and heat sectors in Russia. About 30% of electricity generation comes from co-generation. Electricity is often produced essentially as a by-product of heat, and its sales help cover losses incurred in heat production.

District-heating systems in Russia provide heat and hot water to most of the urban population as well as to industry. Low investment and inadequate maintenance during the 1990s decreased the reliability of supply in many systems. Large energy savings could be achieved especially in terms of reducing losses and through energy efficiency measures. Improving the efficiency of heating plants or replacing them with more decentralised facilities could lead to further efficiencies. IEA data show 3% of all heat generated in Russia is lost in transmission and distribution.[144] However, Russian energy

144. According to IEA methodology, heat production represents all heat production from public CHP and heat plants as well as heat sold by autoproducer CHPs and heat plants to third parties. Fuels used to produce heat for sale are recorded in the transformation sector under CHP and heat plants. Fuels used to produce heat which is not sold is recorded under the sectors in which the fuel use occurs. The production of heat from boilers and heat pumps also reflect only the quantities of heat that is sold. Therefore, transmission losses according to IEA methodology do not include losses of heat, for heat produced but not sold.

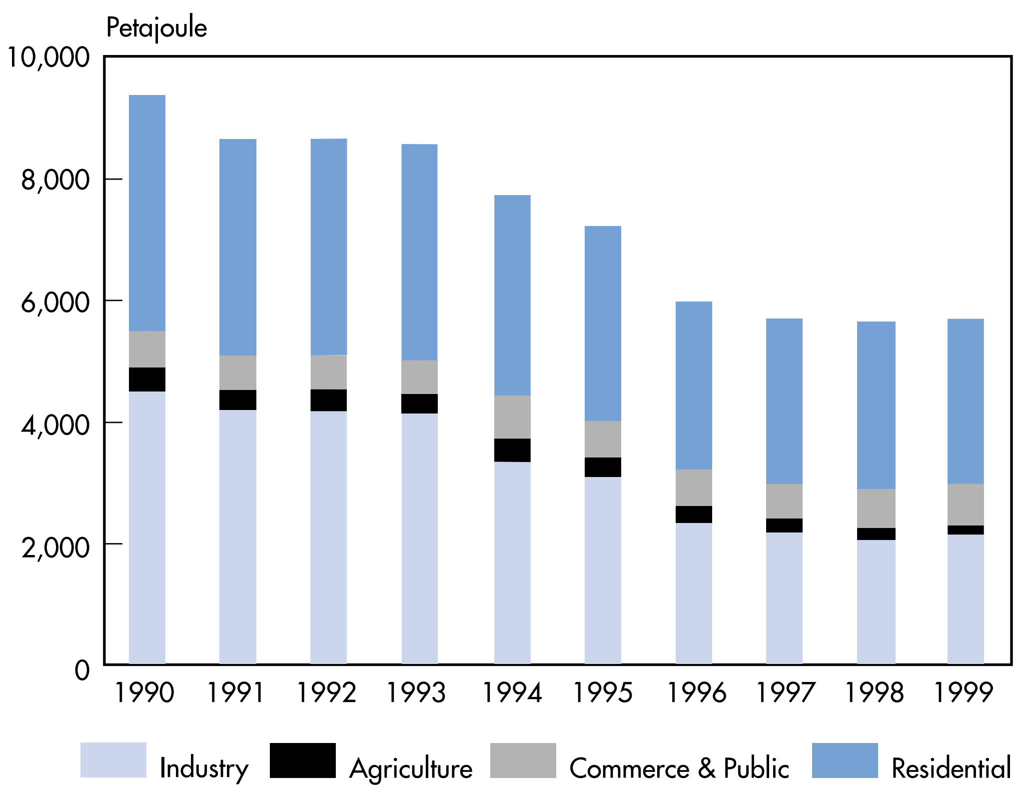
experts estimate heat losses are in the range of 20% to 30%. They argue that this is not reflected in official Russian statistics due to the fact that either the losses are assigned to final consumption or that due to the lack of accurate metering, levels of heat production are often estimated based on norms.

Heat Consumption, Generation and Distribution

Heat Consumption

Heat accounted for 33.2% of Russia's final energy consumption in 1999 and stood at 5,706 PJ (136 Mtoe), down 39% from 1990. The residential sector is the largest heat consumer, with a 48% share in 1999 (Figure 19). Industry[145] has 37%. The largest decrease in consumption occurred in industry (minus 49% between 1993 and 1999). The largest industrial consumers in 1999 were chemicals and petrochemicals, machinery and iron and steel. Residential heat consumption decreased 23% over the same period, while consumption in the agriculture sector fell by 38%.

Figure 19 Heat Consumption by Sector, 1990-1999



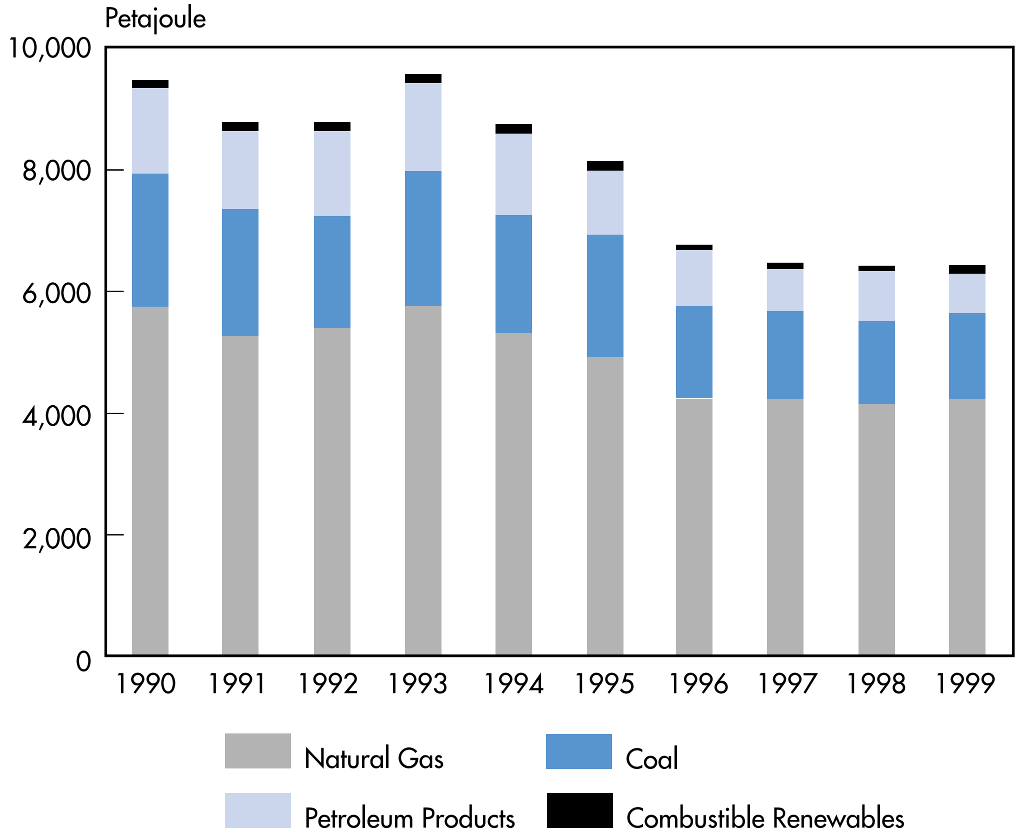
Source: IEA estimates and statistics.

Heat Generation

Heat generation decreased more than one-third between 1990 and 1999, from 9,467 PJ to 6,333 PJ (151 Mtoe). Natural gas, the most important fuel, accounted for 66% of the total in 1999. Coal accounted for 22%. Input fuels for heat-only plants in 1999 amounted to 91.8 Mtoe, or some 15% of total primary energy supply. Figure 20 shows heat generation by fuel.

145. Energy use by company-owned housing is included in industrial consumption. Other large consumers are agriculture, commerce and public services.

Figure 20 Heat Generation by Fuel, 1990-1999



** Heat generation from CHP plants using nuclear power is about 0.2% throughout.*
Source: IEA estimates and statistics.

Heat-only boilers account for some 52% of total heat generation. Public co-generation plants account for about 37%. The rest is produced by industries that generate heat or heat and power for their own consumption. While overall heat generation has decreased, heat from industrial co-generation plants has increased slightly, and stood at about 26% of the total in 1998. UES produced about one-third of the total. Heat provided about 25% of UES's consolidated 1999 revenues.

Regional *energos* are the largest heat producers, using both co-generation plants and heat-only boilers. The *energos* sell their heat to large industries and municipalities, which may supplement such purchases with their own production, usually from heat-only boilers. Residential and commercial customers receive their heat from the municipalities.

Heat Distribution

More than 250,000 km of pipes deliver heat in Russia, and most urban areas are served by district-heating networks. In general, *energos* own the transmission grids, while municipalities own the distribution networks. Below-cost pricing has contributed to under-investment and poor maintenance, with an estimated 60% of the network in need of major repair or replacement. Heat pipes are poorly insulated, leading to large heat losses. It is not possible to control flows in most Russian heating networks. Distribution is often uneven, with overheating in buildings "upstream" and under-heating "downstream". Due to system design, any limitation to heat through a given radiator limits the flow to other radiators in the same building. There is also a general lack of metering in both the transmission/distribution system and for heat output.

Heat Tariffs, Subsidies and Non-payment

The FEC sets guidelines for heat prices to final consumers and municipalities. These prices are calculated to allow suppliers to cover costs of production and transmission. RECs, using these guidelines, set prices or approve prices set by suppliers. In practice, the tariffs usually do *not* cover the costs of supply. Electricity sales from co-generation are used to cross-subsidise losses from heat supply. Prices charged to industries usually exceed those charged to municipalities, even though the costs of supplying industry are lower. Electricity prices vary substantially by region. Industrial tariffs are usually based on the amount of heat consumed, with the higher prices being charged for consumption above amounts stipulated in the supply contracts. Because residential and commercial customers do not have meters, they are typically charged by a formula based on floor space, with the charge frequently included in their rent.

►►► ***Removal of cross-subsidies for heat.*** *Heat costs should be separated from electricity costs for co-generation plants.*[146] *It is also important that accounts for heat supply be clearly separated from those for other services provided by local administrations and that there be no cross-subsidies between such activities. To the extent possible, tariffs charged to each end-user should reflect the cost of supplying that customer.*

In Moscow (see box), the city government sets tariffs for heat in co-ordination with the Moscow City Duma. Two heat-supply companies serve the city: *Mosenergo*, a branch of UES that supplies 80% of residential heat, and *Mosteploenergo*, a state-owned company under the jurisdiction of the Ministry of Energy that supplies the rest. The Moscow city government sets the same tariff for final customers of both companies, despite different cost structures stemming from use of different technologies. The tariff for housing organisations shown in Table 8.16 reflects a subsidy from the city budget that reduces the tariff from 150 roubles/Gcal to 66 roubles/Gcal.

Table 8.16 Moscow Heat Tariffs in 1999

Consumer Groups	Roubles/Gcal	US$/Gcal
Housing organisations	66	3
Industry	126	5
Others	165	7

Source: TACIS, Housing Heating Management Component: Technical Report No.1, 2001.

Tariffs do not cover the full costs of supply. So there are insufficient funds for maintenance and repair. To ensure the long-run operation of the system, final consumers will need to pay tariffs that cover their full costs. Billing should eventually be based on actual consumption and not on size of dwelling, although the lack of individual metering and control systems will make this difficult in the foreseeable future. In the meantime, existing tariffs based on floor space should be increased and bill collection improved.

146. For the different methods, see IEA (1995), *Energy Policies of the Russian Federation*, Paris, available in both English and Russian on the IEA Website at www.iea.org.

Example of a Heat Supply System: Moscow

Heat in Moscow is produced by 15 large combined-heat-and-power plants (CHPs), 70 district and local heating plants (DHPs and LHPs), and 100 local boilers (LBs). Table 8.17 shows their capacity and production.

Table 8.17 The Moscow Heat-Supply System

Designation	Heat Capacity Gcal / h	Heat Production Million Gcal	
		Million Gcal	Percentage
Combined-heat-and-power plants	32,250	79.9	77%
District and local heat plants	13,700	22.7	22%
Local boilers	250	0.4	<1%
Total	46,200	103.0	100%

The primary heat / hot water network includes 2,279 km of pipes with an average diameter of 570 mm, and 21 booster pump stations. Inside city sub-districts, *Mosgorteplo* operates 4,628 sub-stations and *Mosteploentrgo* 1,243. From the sub-stations, secondary networks transfer heating and domestic hot water to buildings. The secondary networks include some 4,400 km operated by *Mosgorteplo* and about 1,245 km operated by *Mosteploenergo*.

Equipment inside apartment houses includes a connection point in the basement; valves, filters, thermometers and manometers; pipes for heat and domestic hot water distribution; and radiators and/or convectors in individual apartments. Individual apartments generally have no meters, although the installation of building meters is beginning. *Mosgorteplo* recently completed installing meters in all the sub-stations it manages.

Both these activities will face opposition from politicians who have tended to view heat as a convenient and "free" form of subsidy to the population. Such a practice risks undermining the long-term viability of district-heating systems.

►►► ***Heat tariffs should cover full costs.*** *As with electricity, heat tariffs should cover full costs in order to maintain the longer-term viability of the system. Ideally, before heat tariffs are increased, priority should be given to installing meters and heat-regulating devices to allow consumers to regulate consumption. Financial support to heat consumers will be more efficient if provided directly to those most in need, rather than subsidising all heat prices.*

9. ENERGY EFFICIENCY

EXECUTIVE SUMMARY

Energy Efficiency Policies

From 1995 to 2000 Russia gradually put into place a legal and regulatory structure to promote energy efficiency. It still had not achieved much success when the period ended. The IEA fully supports the *Main Provisions of the Russian Energy Strategy to 2020* emphasis on reforming the energy price structure as the key to stimulating rational and efficient energy use. A new Federal programme, "Energy Efficient Economy", designed as the main mechanism in the Energy Strategy to improve energy efficiency, in line with the goals of the *Main Provisions*, was approved by the Russian Government Decree N° 796 of 17 November 2001. The Russian Energy Strategy estimates investment needs in the order of $40 to $70 billion over the period from 2001 to 2020. In Russia's unattractive investment environment, efficiency investments should be concentrated in priority areas and sectors where the greatest gains can be made. Low-cost investments can increase consumers' awareness and ability to control their energy consumption. These include the continued introduction and enforcement of standards and labels, metering and building codes and the wider dissemination of information.

Russia's Energy Efficiency Potential

Russia's economic growth depends both on its vast natural resources and on their efficient use. The *Main Provisions* foresees a reduction in the annual energy consumption growth of about 45% by 2020. The energy sector accounts for an estimated 40% of this potential saving, with another 30% from industry, 20% from the residential sector, 7% from transport and 3% from agriculture. Realising residential gains is difficult, however, compared with those in the energy or industrial sectors where targeted programs can yield quick and large results. This points to the need for priority-setting among publicly-financed efficiency investments. Better end-use energy data is needed for this. The fact that these estimates are almost identical with those in the 1995 Energy Strategy based on studies carried out in 1993, underscores the need for better end-use energy data. By 2001, the situation has changed in terms of industry structure and access to energy-efficient technology and information. Furthermore, tougher budget constraints, to deal with the non-payment problem, were increasingly enforced and felt. These factors should enhance Russia's energy efficiency potential.

Barriers to Energy Efficiency Investment

The lack of both private and public finance is a key problem. Investment barriers include low energy prices, lack of competition in the electricity and heat sector and lack of consumer control coupled with a system of billing (on a per resident basis) which provides little incentive for efficiency. On a more macro-economic level, the major barriers, which continue to hamper investment, include the lack of contract enforceability and an unstable investment environment. Mechanisms are needed to provide investors with greater stability and reduce the fiscal and legal risks of long-term investment.

A stability mechanism like that provided by production sharing agreements for investments in the upstream oil sector could help minimise the risks of investing in energy efficiency. The Kyoto Protocol could embrace the attractiveness of some energy-efficiency investments through the use of its "flexible mechanisms", especially Joint Implementation.

Energy Efficiency: A Regional Approach[147]

A regional approach to energy efficiency is essential. The energy situation in each region depends on its natural resources, its distance from main distribution networks and its energy consumption. Reducing energy use is increasingly seen as a way to reduce regional expenditures and free limited budget revenues, increase industrial competitiveness. It can also reduce pollution and improve the comfort, health and safety of citizens. Heat and power subsidies alone absorb 25%-40% of scarce regional and local budgets. Since 1995, many regional administrations have developed legal, regulatory and institutional frameworks for energy efficiency. By mid-2000, 33 regions had energy efficiency laws in place, and 13 more were formulating them.

ENERGY EFFICIENCY POLICIES

Russia's economic growth depends not only on its vast natural resources but also on more energy-efficient use of those resources, in heating systems, companies, buildings, houses and transport. Without such improvements, the Russian energy sector risks hampering overall economic growth, with energy security also at risk in remote regions that are already experiencing fuel shortages. Efficient energy use is also the quickest, most economic way to ease budget constraints in municipalities across all regions. City governments spend 25% to 40% of their budgets on district-heating systems.

Despite the central place of energy efficiency in the 1995 Energy Strategy, only limited success was visible by 2000. The economic downturn during the 1990s did not help this with:

- a drop in industrial output from 1992 to 1998 greater than the drop in industrial energy consumption;
- an increase in the energy sector's share of GDP and the prevalence of low prices for energy inputs;
- the non-payment problem, which reduced incentives to lower costs and energy use.

Federal Energy-Efficiency Policies and Programmes

President Boris Yeltsin signed the federal Law on Energy Conservation in April 1996. The product of a compromise among federal bureaucrats, energy producers, regions and large energy consumers, this long-awaited law elevated the efficient use of energy to the rank of a policy priority. It called for more accountability of producers and consumers and the inclusion of energy-efficiency requirements in federal standards for equipment, materials, buildings and vehicles. It introduced the application of standardisation and certification of energy-consuming equipment. It made energy audits

147. The Russian Federation is made up of 89 sub-federal *regions*, which consist of 21 republics, 49 oblasts, one autonomous oblast, six krais (territories), ten autonomous okrugs (areas) and the cities of Moscow and St. Petersburg, which have special status.

compulsory at large companies and set a target for metering all energy consumption in the Russian Federation by 2000, as well as improved statistical reporting on energy consumption. It provided mechanisms to promote investment in energy efficiency. These mechanisms included government guarantees for foreign investments in co-operative energy-efficiency projects with Russian firms. The law called for differentiated energy tariffs by season and time of day. It relieved consumers of having to pay for contracted energy supplies if they actually consumed less due to energy-efficiency measures.

The 1996 law divided the responsibility between the federal and regional governments. Like the federal law, however, many of the regional statutes are too general to have much impact or energy-efficiency activity. But regions with a real interest in efficiency improvements were given substantial room to develop their own legislation.

In January 1998 the federal programme on "Energy Conservation in Russia" was adopted by Government Decree N° 80, which recommended that regional administrations develop their own programmes. The Ministry of Energy began working actively with the regions and signed more than 20 energy-efficiency agreements with them. The programme focuses on voluntary investment in energy-efficiency improvements, as planned by energy producers and consumers over the seven years from 1998 to 2005. The voluntary character of the programme applies to businesses not owned by the state. In the gas and electricity industry, where the state is the majority shareholder, the agreements are, in practice, mandatory.

This programme aims to reduce the energy intensity of GDP by 13.4% by 2005. It intends to do this so by implementing the main energy-efficiency policies identified in the 1995 Energy Strategy and the Law on Energy Conservation. The government will use market mechanisms, regulation, the reduction of energy subsidies and the reform of energy prices and tariffs. Its main emphasis will be on the energy, residential and commercial sectors, energy-intensive industries and the electricity generating industry. Emphasis is on the production and installation of certified energy meters and regulating devices. The estimated investment needs of the program are $9.2 billion, to be financed by company profits (47%), bank credits (30%), local budgets (20%) and the federal budget (3%).

The Ministry of Energy is mandated to co-ordinate implementation of energy-efficiency programmes. The Ministry's Department for State Energy Supervision and Energy Efficiency has a central role in all industrial, regional and international efficiency initiatives. The department oversees Ministry of Energy activities, such as energy audits, assessments, certifications, training, and consultations. It also co-ordinates the energy-efficiency work of other ministries.

In Russia's unattractive investment environment, much of the federal programme has a somewhat hypothetical character. It lacks a clear distribution of who is responsible for implementation. Institutional and financial support from the federal government are minimal. The modest quantitative target – to reduce energy intensity of GDP by just 13.4% in eight years – would be reached in any case with the structural changes accompanying economic recovery. Indeed, even larger energy-intensity reductions are expected. With limited financial support from the federal government, the programme will depend mostly on regional administrations and the private sector. Regional representations at the April 1998 Duma hearings on energy efficiency complained that there is still a need to:

- draw on electricity and heat tariffs for funds to finance conservation projects;
- prohibit energy suppliers from charging consumers for incomplete use of contracted energy supplies due to energy-efficiency improvements; and
- allow independent electricity and heat producers access to the grid.

The "Energy-Efficient Economy" programme in line with the goals set in the *Main Provisions* is the latest federal attempt[148] to promote efficiency investment throughout the economy. Its goal is to introduce energy-saving technologies in the industrial sector and the economy in general, as well as in housing and utilities. Its sub-programmes for 2001-2005 and out to 2010 include: the energy efficiency of the energy sector, safety and development of nuclear energy, energy efficiency in consumption, ecological aspects, monitoring, legal framework, and organisation. This programme will require an estimated $3 to $5 billion in investment from 2001 to 2005, depending on the rate of economic growth.

►►► ***Economic Competitiveness of Energy-Efficiency Investments.*** *The introduction of the energy efficient economy commendably outlines specific investment needs in the energy-producing and consuming sectors of the economy. With limited investment available and an unattractive investment environment, generally, efficiency gains could be maximised if energy-efficiency investments were focussed on priority areas and sectors.*

Energy Price-Reform Policies

Prices are the major criterion on which consumers assess the value of energy-saving measures. Efficient systems and equipment usually, although not always, cost more than the technology they replace. The higher the price of energy, of course, the more attractive the opportunities to conserve it. The more energy prices reflect the full costs of producing energy and mitigating the environmental damage it causes, the more potential there will be for energy savings[149].

Underpricing of energy alone produces major distortions in energy consumption and high economic costs. A recent IEA publication[150] estimates that annual primary energy consumption in Russia could be reduced by 18% (107 Mtoe/year) if price subsidies were removed. Natural gas and electricity use would fall the most. Carbon dioxide emissions would also drop by about 20%. This economic analysis takes no account of the political practicalities of price reform or of structural and economic barriers to investment. The annual economic-efficiency cost[151] is estimated at 39 billion roubles in 1997 roubles ($7 billion). The pure financial costs borne by energy producers and

148. The Russian Government approved this programme on 17 November 2001 by Government Decree N° 796.
149. When prices are distorted by subsidies, they do not reflect the true cost of energy.
150. IEA (2000), *World Energy Outlook: Insights 1999* – Looking at Energy Subsidies: Getting the Prices Right, Paris.
151. An economically efficient energy price is the price, which includes all relevant costs. Energy price subsidies lower energy prices below that which consumers would otherwise pay, leading to *economic-efficiency costs*. For more information see (IEA, 2000), *World Energy Outlook: Insights 1999* – Looking at Energy Subsidies: Getting the Prices Right, Paris.

suppliers, because the prices they receive are below market value, and by the Federal Government, which directly subsidises energy, are estimated at 190 billion roubles (in 1997 roubles), over $30 billion.

The price effect on consumers was indeed the main factor stimulating efficiency gains in IEA countries in the 1970's. The major policy tool to stimulate efficient use of energy is increasing energy prices to ensure that they cover costs. The *Main Provisions* pay close attention to this principle and to the need to realise relative energy prices to regain balance in energy demand. The *Main Provisions* call for natural-gas prices to increase by a factor of 2.5 by 2003 and another 1.4 by 2005, so that by 2007 they will reach equilibrium with European gas prices, at about 3.7-4 times current prices. Higher coal prices will match the natural-gas price, leading to higher electricity and central-heating prices. Projected electricity prices will more than triple by 2010, with most of the rise accomplished by 2005.

►►► ***The ambitious goals for increases in price levels outlined in the Main Provisions are of key importance in stimulating rational and efficient energy use.*** *Barriers exist, however, due to the large share of energy consumption in disposable income and industrial input costs and to the structural inefficiencies of Russian central-heating systems. Any financial support to consumers will be more efficient if provided directly to those most in need, rather than via general energy-price subsidies.*

Structural Energy-Efficiency Policies

The *Main Provisions* base their estimates of potential efficiency mainly on technical factors and equipment costs, without sufficient consideration of the likely market penetration of new technology, consumer behavior and policy measures. IEA experience has shown that it is essential to distinguish between potential technological achievements and the "real world" of consumers motivated by non-economic considerations, such as comfort, quality and availability. Nevertheless, Russia has made some progress with non-economic and structural measures to enhance energy-efficient consumption and provide consumers with control over their consumption, comfort and product choices.

Standards and Labels

The standards system is based on the following federal laws passed in 1992 and 1993: *"On standardisation and on certification of products and services", "On uniformity of metering"* and *"Basics of Russia's legislation on labour protection"*. The effectiveness and enforcement of these standards and regulations could be much improved. There is insufficient motivation for energy-efficiency improvements, because of low electricity prices, low incomes and the federal protection of manufacturers. Compliance with world standards is not a priority for domestic manufacturers who do not intend to enter the world market. Standards do exist that would make a difference if they were seriously enforced.

►►► ***Export-oriented enterprises should be encouraged to set standards in compliance with international requirements.*** *As industry associations and professional societies increase in number and become more informed about international standards, the standards will naturally be more widely applied.*

Building Codes (SNiPs)

Until recently, Russian building codes (SNiPs) have focused on setting minimum "prescriptive" requirements. But current standards are based on a new, "performance" approach, described in the *System for National Standards in Construction* (SNiP 10-01-

94). *Building Thermal Performance*, 1995 edition (SNiP II-3-79*), contains national standards revised along these lines and applicable to new buildings and renovations above a certain cost. Regional and municipal codes have also become stricter. The 1995 SNiP combines the old system, which specified the thermal characteristics of individual components, with a new approach based on the performance of the entire building. This new method is expected to enhance innovations in building design by providing greater flexibility for designers to meet and, if possible, exceed the requirements. A performance-based system can adjust more rapidly and effectively to changing energy prices, allowing for performance requirements to track increasing energy prices without having to revisit design standards on a component-by-component basis.

Despite this progress, there still is little institutional support for good construction practices or for good building and equipment maintenance, particularly in structures heated by local boilers or room stoves. The market for private property has only begun to develop. Under these circumstances, a market for energy-efficient building supplies will take some time to emerge.

Metering

Energy meters are a rarity. Consumers often do not know how much energy or heat they actually use and pay more than necessary. Customers are often billed for heat that they never received. In recent studies, the heat meters in only 2%-5% of buildings showed higher volumes than contracts stipulated. Substantial budget savings can be made through metering. All regional energy-efficiency laws include requirements for compulsory metering. Some are more specific than others, with time limits for meter installation and use. Much work remains to improve public support for metering. Difficulties, including vandalism, have arisen because consumers cannot regulate their energy use. They have no thermostats and they fear that metered energy bills will be higher than non-metered ones.

►►► ***Installation of meters and thermostats should accelerate.*** *Continued metering is essential. Ensuring that consumers can control their energy consumption has special importance in view of the planned increase in heat tariffs.*

Energy Auditing

Some regional laws propose energy auditing as another method of control. The Chelyabinsk law, for example, is based on compulsory auditing and expert evaluation of projects. This approach is suitable for state-owned companies, publicly-supported organisations and consumers looking for tax breaks, where withholding state support can be the penalty for non-compliance. For other consumers, compulsory auditing makes little sense, because it is not clear who pays for the audit and what exactly it means. In a functioning market, the need to be competitive will automatically force private companies to reduce costs and use energy more efficiently. Positive incentives rather than penalties should be the basis for an auditing requirement.

Information Gathering and Dissemination

Energy-efficiency improvements are impossible without a well-organised system for gathering and processing energy-consumption data at all levels of aggregation: nationally and by town, district and region. A baseline must be established against which to evaluate projects and policies and to measure results. Many regional laws already include information requirements, and that is an encouraging development. For example, the

Tula regional Energy Efficiency Law includes a special clause on statistical reporting. It requires:

- collection of consumption data and efficiency indicators by the regional statistics committee;
- that regional statistical bodies, in co-ordination with the Ministry of Energy and regional conservation programmes, introduce forms for reporting the efficiency of energy use.

Information support for energy conservation is crucial everywhere, but especially in Russia where efficiency drives are beginning to build momentum. Whereas a few years ago only one or two energy efficiency bulletins existed in Russia, by late 2001 over twenty periodicals are in circulation. Consumers must better understand how they can use energy more efficiently and find information on potential partners and technologies. Existing regional efficiency laws charge energy conservation authorities with ensuring:

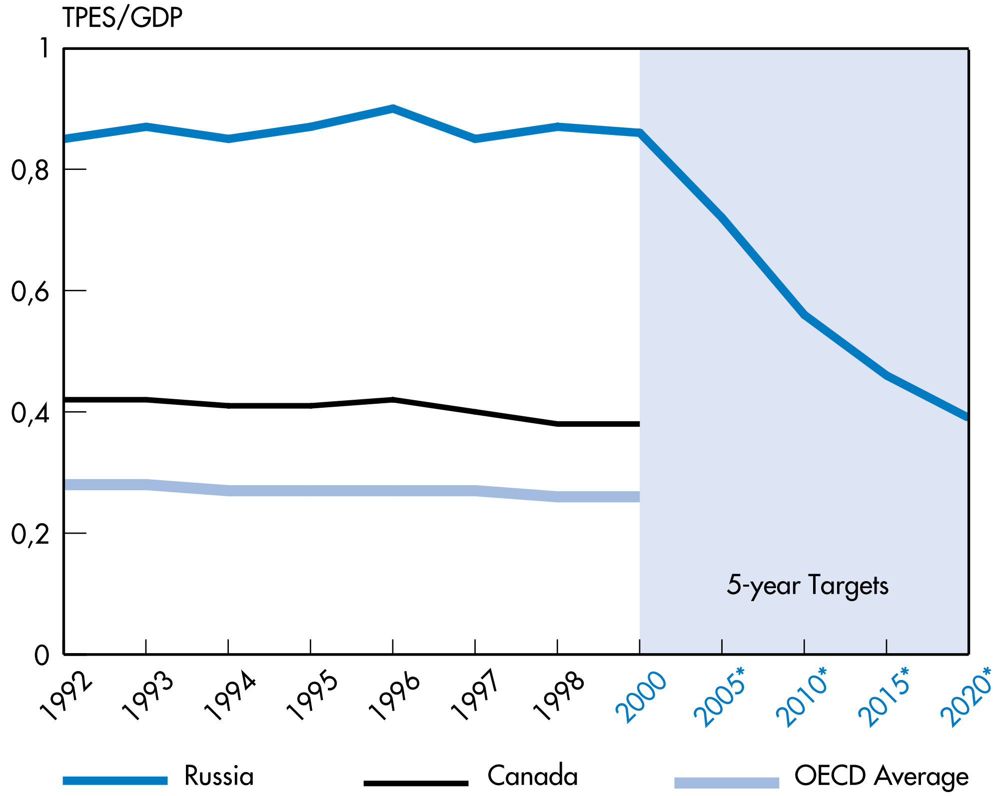
- that energy-conservation programmes teach the basics of efficient fuel and energy use in schools, and that they train teaching staff, engineers and technicians involved in supplying energy to businesses;
- the organisation of exhibitions of energy-efficient equipment and technologies, and the involvement of mass media in popularising energy-efficiency improvements.

►►► ***Informing end-users of planned energy price increases and raising awareness of the associated benefits of energy efficiency are essential for success.*** *Progress to date in raising awareness of the need to consume energy more efficiently is commendable. But a comprehensive programme is essential.*

RUSSIA'S ENERGY EFFICIENCY POTENTIAL

The ambitious outlook for energy-efficiency improvement in the *Main Provisions* depends upon successful economic reform well beyond the energy sector. The *Main Provisions* foresee a reduction in the ratio of energy use to GDP of about 55% by 2020, to about that of Canada (Figure 21). At first glance, Canada would appear to offer a useful comparison because its climate, surface area and natural-resource endowment resemble those of Russia. However, major differences exist between the two countries due to their very different levels of economic development. Primary activities, such as agriculture, resource extraction and transport have bigger shares in Russian GDP than in Canada's, where services have a much larger share. More important, Canada has much higher per-capita travel, particularly in cars. Heated area in homes and service establishments, are from two to four times larger than in Russia. Canada's freight haulage per capita is comparable to that in Russia, excluding natural gas in pipelines. Canada's heavy industry has less total output than Russia's and holds a far smaller share of GDP.

Figure 21 Comparative Energy Intensities and Outlook for Russia, TPES/GDP (toe per thousand 1990 US dollars)



* Outlook for Energy Intensity Reduction in "Main Provisions of the Energy Strategy of the Russian Federation to 2020, November 2000".

Studies in the late 1980s by the Energy Research Institute of the Russian Academy of Science compared energy efficiency indicators in the USSR, USA, and Western Europe from 1970 to 1985 with an outlook to 2000[152]. The study results showed Soviet energy intensity of GDP 34% higher than the US and almost 100% higher than that of Western Europe in 1985. The energy intensity of the Soviet energy sector was shown to be twice that of the US and three times higher than Western Europe's in 1985, due largely to the use of outdated technology in the production, refining and transmission of energy resources and suppliers. Past studies by Lawrence Berkley National Laboratory have shown that in the late 1980s Soviet space heating of homes and buildings was twice as energy intensive as that in Scandinavian countries. Soviet industry used roughly 50% more energy for a given product than did European countries. Other LBNL studies show that in the late 1980s, Aeroflot stood on a par with the US and European airlines in energy consumption per passenger-km, but only because its planes flew completely full. Soviet-era airplanes used 50% more fuel per *seat*-km than western ones. The rapid transition of Aeroflot to western aircraft with lower energy intensities is a welcome sign that efficiencies can improve rapidly when both economic and political constraints are removed. The expected increase in car use, air travel and trucking, however, will

152. Comparison of energy development and energy efficiency indicators in the USSR, USA, and Western Europe in 1991-2000). Vol. 1 and 2. Energy Research Institute of RF Academy of Science. I. Bashmakov, A. Beschinsky, N. Bogoslavskaya, et. al. I. Bashmakov, A. Beschinsky Editors. Moscow, 1990.

increase energy demand. This effect has already changed energy-demand patterns in Central and Eastern Europe radically. It is not clear whether the Russian projections account for it.

The *Main Provisions* foresees TPES growing from about 650 Mtoe (or 929 million tonnes of coal equivalent (mtce)) in 2000 to 885 Mtoe (or 1,265 mtce) in 2020, instead of a projected 1,867 Mtoe (or 2,670 mtce) at the present level of energy intensity. This would translate into a reduction in annual consumption growth of between 46% over the 2000 to 2020 period. About 290 Mtoe (360-430 mtce), or 30% of this reduction would come from effective implementation of energy efficiency measures rather than structural change. Most of the reduction would result from structural change as the economy shifts away from heavy industry and manufacturing to a more service-oriented GDP. These changes account for about 70% of the reduction by 2020 (Figure 22). These estimates are almost identical with those in the 1995 Energy Strategy based on studies carried out in 1993. By 2000, however, the situation had changed in terms of industry structure and access to energy-efficient technology and information. Tough budget constraints, to deal with the non-payment problem, were increasingly enforced and felt.

Up to date international comparisons of sectoral energy-intensity indicators for the OECD as a whole and for some member countries would help put the Russian situation into perspective. Some sectors may appear to have more energy-saving potential than others, when compared to similar sectors in other countries. Time series of such indicators could reveal the sectors where policies have worked best. Such information is needed to set priorities for programmes and to write legislation aimed at specific sectors and sub-sectors.

►►► ***The disaggregated indicator approach is one of many important tools for formulating and implementing energy-efficiency policies.*** *Policies should create incentives for efficiency investments instead of imposing change. Final decisions should be based on the financial viability of each project.*

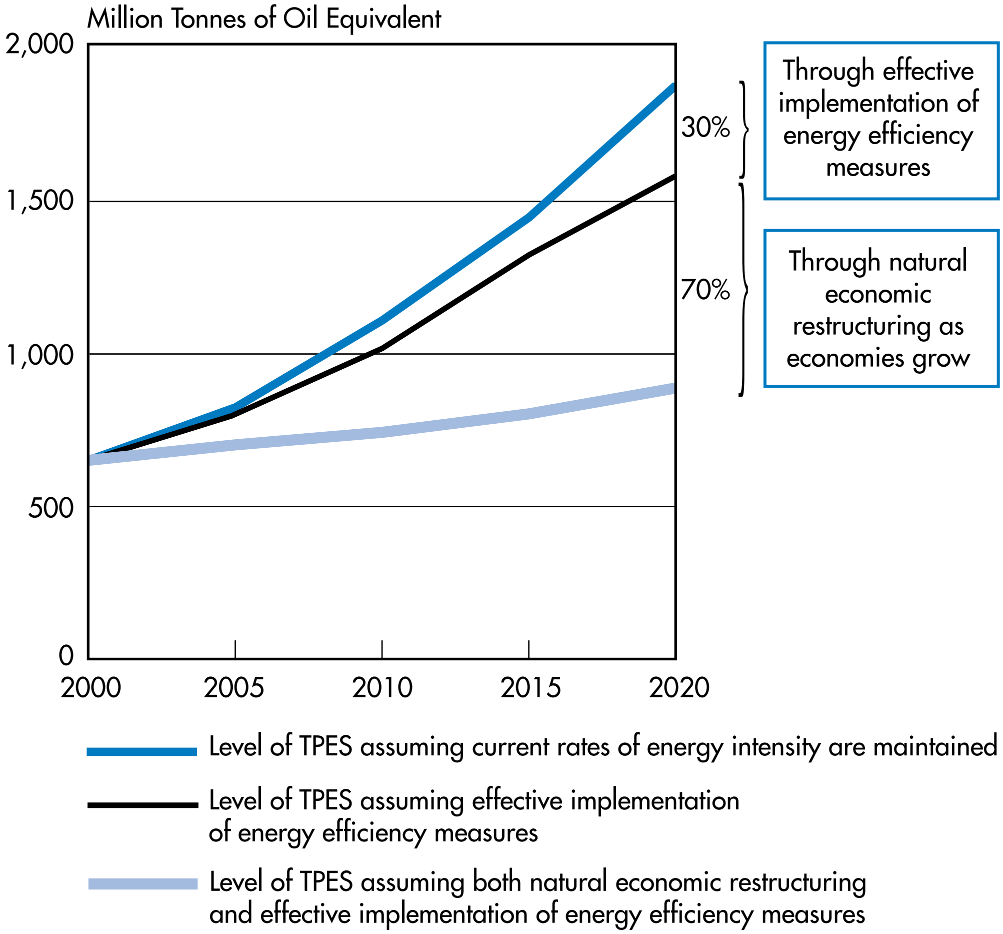
Energy Efficiency Potential in the Energy Sector

With large structural difference in energy-sector characteristics between Russia and other industrialised countries, estimating the Russian medium-term savings potential accurately would require a plant-by-plant assessment. Moreover, the current high transmission and distribution losses result directly from the very large share of centrally-produced heat in the economy. There are major unexplained breaks and swings in the data for transformation and transmission losses. It would be very helpful if the reasons for these irregularities were explored. In the days of the centrally-planned economy, such losses were often attributed to final consumption at the end of the pipeline and not to the heat producer.

►►► ***Extending Data Collection and Evaluation Efforts.*** *To improve the focus, design and implementation of energy-efficiency programs, extended and improved data collection and evaluation will be essential.*

Refurbishment of district-heating systems is a cost-efficient way to achieve energy efficiencies with relatively simple technology: retrofit of boilers, insulation of heat pipes

Figure 22 Growth in TPES in 2000-2020 (Business as Usual vs. Energy Efficient Energy Consumption)



Source: "Main Provisions of the Energy Strategy of the Russian Federation to 2020", November 2000.

with modern material, installation of heat meters. The ownership of district heating systems has largely moved from central boilers and CHPs to municipalities. Small local boilers have replaced pipeline connections to large CHPs. This has not always translated into cost reductions but it has tended to improve cash flow. Municipalities are keeping a greater share of revenues, and their take will increase as price subsidies for households are gradually eliminated. Self-financed energy-efficiency investments will then become more possible.

Sector-Specific Policies and Measures

Local administrations have often feared that their funding from regional or national budgets would be reduced if they improved energy efficiency. In 1998, some regions adopted regulations to guarantee that municipalities' budgeted funds for energy expenditures would remain at their disposal even if energy-saving programmes reduced expenditures.

Many of the investments that UES and Gazprom have made in new capacity and modernisation have had a positive effect on overall energy efficiency. They use new technologies and phase out less efficient ones. Both firms have departments for environmental policies and programs, and both are very interested in participating in Joint Implementation. The Federal government encourages both companies to help users save energy. But no strong government policy encourages them to develop an integrated resource-planning programme for the mutual benefit of producers and consumers. The *Main Provisions* tries to push such an approach with the introduction of a federal Energy Efficient Economy programme. The program's goal is to reduce the energy intensity of GDP through the co-ordinated introduction of energy-saving technologies in industry and the economy in general, including housing and the utilities.

Energy Efficiency Potential of the Electricity and Heat Sectors. *As the many old and inefficient power and CHP plants are phased out and replaced, the efficiency of transformation can increase. This is particularly important in view of the stated need to increase coal use in the electricity and heat sector. The comparative economics of investments in demand-side management and of introducing new coal-fired energy supply should be considered.*

Energy Efficiency Potential in Manufacturing

The Russian manufacturing sector accounted for 34% of total final consumption in 1999, a share it maintained over the 1990s. With the exception of the iron-and-steel and machinery sectors, energy consumption by sector is generally in line with other industrialised countries of the OECD. The ratio of energy consumed per tonne of output allows useful comparison of energy efficiency within a sector and suggests the sector's international competitiveness. This is especially the case in the iron-and-steel sector, where energy is an extremely large input to the production process. As shown in Table 9.1, energy consumed per tonne of steel produced in Russia was almost three times that of the US in 1995. Russian energy efficiency in this sector improved between 1995 and 1999, with energy consumption dropping 20%. In 1999, however, it still took more than twice the energy to produce a tonne of steel in Russia than in the US.

Table 9.1 Energy Consumption in the Steel Industry

	1995	1996	1997	1998	1999
Russia					
Energy use in Mtoe	38.6	35.3	31.6	29.8	30.8
Steel production in million tonnes	51.6	49.3	48.5	43.8	51.5
Ratio of tonne of oil equivalent to tonne of steel produced	0.75	0.72	0.65	0.68	0.60
United States					
Energy use in Mtoe	25.0	24.9	26.7	27.0	26.1
Steel production in million tonnes	95.2	95.5	98.5	97.7	97.4
Ratio of tonne of oil equivalent to tonne of steel produced	0.26	0.26	0.27	0.28	0.27

Over the 1990s, Russian energy-efficiency policies that might have tried to improve efficiency in the industrial sector were either not in place or too weak to have effect. However, a few privatised industrial plants, which had to pay their energy bills and could self-finance energy-efficiency investments with export revenues, achieved remarkable results (see box). Yet they were so few that they had no visible impact on the national intensity indicators. At best they may have compensated for otherwise increasing energy intensity during the economic decline. In certain manufacturing industries in other transition countries, energy intensity increased during economic downturns because of large overhead energy use. When the output of ten production lines for one product drops by half, for example, Western management would try to shut down five entirely and run only the other five. In Russia, for social welfare and technical reasons, all ten lines might have stayed in operation when reduced output would have justified their shutdown.

►►► ***Because of its Soviet legacy, Russian industry needs to restructure, streamline costs and ensure that its products meet demand in the most economic and environmentally safe way.*** *The handful of energy efficiency success stories in Russia's industrial sector illustrates how competitive forces spur this on relative to regulated monopolistic markets.*

The UralMash company: successful investments in energy efficiency[153]

The UralMash company, established in 1933 at Ekaterinburg, employed 40,000 people in 1990. In Soviet times, it was the biggest machine tool and arms manufacturer in the USSR, with an output of 300,000 tonnes per year. Uralmash's production slumped to 41,000 tonnes in 1993. Under the new management, UralMash reduced its total energy costs by more than 30% in 1996 and 1997.

As a first step, it set up an energy-monitoring system. New metering brought dramatic reduction in hot-water consumption. New gas meters ensured that UralMash was charged only for what it used. Workshop heating was improved by concentrating work in certain buildings, the installation of radiant heaters, *which reduced heating costs of 45% to 60%* and automatic controls. Collection of data from the original electricity meters was centralised to indicate the effect of individual plant loads on consumption. Electricity meters were adjusted to prevent overpayment of electricity bills.

Energy Efficiency Potential in the Residential Sector

Residential energy consumption in Russia is almost as large as in manufacturing, as is typical for lower-income countries in harsh climates. In 1999, Russian TFC in the industrial sector was 138.2 Mtoe and that of the residential sector, 135.9 Mtoe. On a per-capita basis, residential energy consumption roughly equals that in Canada, but Canada has three times Russia's per capita floor space and its electric appliances are larger and more widespread. Thus, Russian residential energy consumption is at least two-to-three times more energy-inefficient than Canada's. The reasons are known: lack of consumer control over heat regulation, lack of private ownership of apartments, non-payment and price subsidies.

Russia nevertheless has made considerable progress since 1993. Per capita residential energy consumption has decreased 18% over the period from 1993 to 1999[154], dropping from 1.14 to 0.93 toe per capita. However, data to analyse this trend in more detail

153. IEA (1997), *Energy Efficiency Initiative*, Volume 2, Paris
154. Some experts question how much of this progress is due to "under-heating" as opposed to efficiency gains.

remain inadequate. For example, the achievements would appear even greater if the numbers could show residential consumption relative to available residential floor space, which has increased by 10% since 1992.[155] Furthermore, it is critical for analysts to be able to identify:

- how much of the apparent progress arises from more appropriately reporting district heating losses and ascribing them to the producer rather than the consumer;
- how much can be attributed to actual efficiency improvements;
- which national, regional or local policies were instrumental in achieving this result.

The apparent reduction of residential energy intensity is all the more surprising in view of continued heavy cross-subsidies for residential electricity and gas tariffs. At least one major policy success may have occurred in the heat sector, where municipalities used to carry the greatest burden in subsidising heat prices. Recent budgetary constraints have provided a powerful incentive to raise heat prices and increase payment discipline.

In the *Main Provisions*, the Russian Ministry of Energy attributes about 10% of the projected reduction in energy consumption over the period to 2020 to the residential sector. This estimate would seem reasonable over a 20 year period, despite the fact that it is much more difficult in practice to realise efficiency potential in the residential sector than in the energy or industrial sectors, where targeted programs can result in large gains. Recent World Bank studies of an ongoing, major housing program in several Russian cities have shown that the cost of refurbishing an average-sized apartment for better heating performance varies from $200 to $4,000, depending on the existing state of repair and the degree of improvement sought. The average cost is about $1,000 per apartment. Considering that at least half of the apartment stock needs refurbishment, an estimate of the total costs comes to around $15 to $20 billion. Payback periods for this type of investment vary between two and sixteen years. Most individual cases exceed ten years. When thermal improvements are made along with general refurbishment, however, the payback times for the costs of thermal improvements drop significantly. The World Bank, in co-operation with the Russian Centre for Energy Efficiency (CENEF, Moscow), has started a programme of ten district-heating projects for residential energy efficiency, totalling $233 million. Whether and when this pilot programme will be emulated on a large scale will depend not only on the availability of credits from the banking system but also on the growth of personal incomes.

Several federal and local housing programmes have set specific standards for insulation and heat consumption per square meter and per degree-day in new buildings, and in the rehabilitation of old buildings. They reduce specific consumption to about 50% of previous standards. Compulsory building codes are very useful when no public funds are available for more expensive activities, such as assistance to energy-efficiency investment or educational programmes. Much has been done recently, including voluntary participation in the establishment of "energy passports" and certificates for buildings. A key problem remains the transfer of ownership of apartments to private individuals or co-operatives and the vesting of authority in occupants, whether owners or renters, to undertake improvements and share benefits with owners.

155. Source: CENEF, Moscow.

Sources of Residential Energy Savings

The key energy uses in households are space- and water-heating, electric appliances, lighting and cooking. Cooking and lighting tend to dominate in lower-income countries, except in very cold climates, where space heating is important. Developments in residential energy use in western Europe will differ markedly from those in Central and Eastern Europe and in CIS countries in coming years, partly due to more energy-efficient equipment and partly to penetration levels that approach saturation in Western Europe for some equipment. CEE/CIS countries, therefore, will probably see significant efficiency improvements as their incomes rise and households acquire new appliances and equipment. Growth in the size of homes and demand for comfort and convenience will offset this trend to some extent.

Experience in IEA countries suggests that energy prices have had a profound impact on energy use for space- and water-heating. Relative prices affect the choice of fuel as well as the share of electricity used in applications for which other fuels can readily substitute, such as space- and water-heating, but the end-use price of electricity has generally varied less than that of other fuels in IEA countries. Another lesson from IEA experience is that efficiency standards for appliances and thermal standards for new residential units with electric heat have also had a demonstrable effect in restraining electricity use. Electricity prices have also affected the intensity of uses not conducive to fuel substitution, such as lighting and appliances. Careful examination of the evolution of both fuel and electricity use in western countries shows little rebound effect, either when prices fall or when efficiency improves significantly or both.[156]

►►► ***The residential sector deserves special attention in the forming of energy-efficiency policies.*** *Clearly it is harder to realise efficiency gains in the residential sector than in the energy or manufacturing sectors, where targeted programs can have great effect. Assessment of the most efficient and effective measures would help set priorities for investment in residential efficiency efforts. Emphasis could usefully be placed on less investment-intensive measures such as building codes, standards and efficiency labels.*

Energy-Efficiency Potential in the Transportation Sector

The share of commercial and private transport in Russian energy consumption is small (20% in 1999) compared with that in the OECD area (34%).[157] To analyse it properly, the intensity indicator needs to be further broken down by transport mode and by private or commercial use. It should be based on tonne of freight/km and passenger travel/km instead of strict volumes or other estimates of contributions to GDP. Unfortunately, such data are not systematically collected in Russia. To the extent that commercial transportation becomes privatised and the share of private cars increases, fuel-price incentives will become more effective and will lead to improved efficiency. This will not reverse the trend towards increased transport-fuel use but it is likely to slow it down. On the other hand, western-style cars tend to be more powerful than

156. IEA (1997), *Indicators of Energy Use and Efficiency*, Paris, OECD.
157. Russian statistics count natural-gas transmission losses, which would nearly double this share, while OECD statistics do not ascribe transmission losses as transportation.

their Soviet-era counterparts, so increasing vehicle-size might erode any savings. In any case, the number of cars per capita has shot up since 1991 and is likely to grow far faster than efficiencies can increase, as is the case in almost every other economy in transition.

Sector Specific Policies and Measures

IEA experience has shown the introduction of fuel taxes is the best direct energy-efficiency policy for the transport sector. It is, however, politically difficult. Russia presently has a 7% sales tax included in the tax component of gasoline prices. Together with VAT and excise tax levied at intermediate market stages, total taxes on gasoline make up 50% of the pump price. The Duma recently refused a draft law to increase gasoline taxation. Consumption norms for engines, an alternative to taxation, require considerable investment by car manufacturers. In IEA countries, as in Russia, manufacturers are reluctant to make these investments unless they have large export shares. In 1998 Denmark placed a yearly tax on existing cars that rises with their original test-fuel-consumption. This "green owner fee" appears to be shifting the choice of new cars towards those using somewhat less fuel.[158]

Russia has launched a number of energy-efficiency initiatives for transport, most of which have failed. In 1994 the deputy minister of transport approved a programme for "Reduction of Climate-Affecting Emissions by the Transport Sector". It listed 40 specific policy instruments: emission norms, certification, monitoring, penalties, tax incentives, and others. None of them was implemented due to worsening federal budget constraints. Despite this, research and development of new transport technologies continues to be an important concern of the ministry. In 1995, it launched a target programme called "Efficiency of Fuel and Energy Resources in Transport" that aimed to increase the number of diesel road vehicles, replace old airplanes and improve fuels and fuel additives. It too was never implemented, for financial reasons. A recently passed law stipulates that compressed natural gas must be half as expensive as ordinary gasoline. In response, the Moscow city government planned to convert 5,000 municipal buses to gas by 2000 with its own budget funds. Gazprom supported this programme, but the Moscow city government does not have enough money to build the necessary 2,200 filling stations. Finally, a few large public transportation projects are in their implementation stages. The World Bank is financing 1,500 new buses and 300 new trolley buses in 13 cities at a total cost of $600 Million.

After cars, the most important energy-users in Russia are trucks. Soviet-era trucks were inefficient and were run inefficiently. They were often driven circuitously to gain "turnover" in tonne-kilometres run. Prior to 1995, there was also a high share of gasoline trucks. With domestic gasoline prices generally at world levels since 1995 (in terms of PPP), gasoline trucks have become more expensive to operate, particularly in competition with diesel-powered ones. The overall ratio of fuel used to tonne-km is likely to decline as private trucking firms compete to lower costs. On the other hand, changes in the economy towards more consumer products and fewer raw materials, as well as towards smaller companies with fewer large bulk shipments, imply a greater role for trucking in overall freight transport, as has been the case in every western country over time. Furthermore, contracting gasoline consumption by trucks and buses

158. IEA (2000), *The Road from Kyoto*, Paris.

will not likely be offset completely by increasing private automobile and light commercial vehicle consumption over the next decade.

The other significant area of energy use in transportation is civil aviation. Before 1991, Aeroflot was the largest airline in the world and Soviet aviation the second-largest energy consumer after the US airlines. Rapid reform has seen the deregulation of ticket prices, a rise in fuel costs and the demise of most of the inefficient Soviet-era aircraft. Thus, overall efficiency has improved and will continue to do so. The large potential for energy savings as the domestic aircraft fleet continues to modernise will limit the overall rise in energy use. As with other modes of transport, air travel, which typically grows faster than GDP in times of prosperity, will certainly grow as the economy recovers.

Energy Efficiency Potential in the Agriculture Sector

Russian agriculture used 4% of all energy consumed in the country in 1999. OECD countries, including Canada, used only 2%. Despite the imperfections of available indicators, the data for Russian agriculture as compared with those for Canada and the OECD clearly show a distinct potential for energy-efficiency improvements. Yet Russian agriculture appears farther away from privatisation than does commercial transport, and so does the likelihood for rapid progress in energy efficiency. An authoritative, independent study to assess the possible reasons for the present inefficiencies in agriculture such as outdated machinery, transport losses and theft, would help form a basis for policies for long-term improvement.

Energy Efficiency Potential in the Service Sector

Services generate the biggest share of GDP in Russia, as they do in the OECD area. But, while most services are private in OECD Member countries, public services dominate in Russia. Floor area per employee is far lower than in most IEA countries. Heat and fuel use per square meter during the Soviet era was almost twice that of other cold countries. In 1999, the Russian service sector consumed 6% of TFC compared to the OECD average of 11% and 13% for Canada. An in-depth review may conclude that part of the energy use defined as "residual" actually belongs in the service sector. Once this data shortcoming is corrected, energy intensity of the Russian service sector may turn out to be much higher than presently shown. It would therefore have higher energy-efficiency potential than its Canadian and OECD-wide counterparts. Audits of public buildings have shown that certain heat saving investments can produce relatively short paybacks. A federal programme for energy efficiency in public buildings and agencies has recently been put in place. Furthermore, some heat needs will decline simply because increased use of electricity provides some "free" heat to buildings in the winter. On the other hand, Russian summers are warm and humid, and the importance of air conditioning in offices and hospitals should not be underestimated.

►►► ***Attention should be paid to the energy-efficiency potential in the service sector.*** *International comparisons of the size of the potential efficiency gains indicate the possibility of rapid rewards for energy-efficiency investments in the service sector as a whole. As hard budget constraints are enforced, energy-efficiency gains will become increasingly valuable.*

BARRIERS TO ENERGY EFFICIENCY INVESTMENT

Under-investment in energy efficiency is not unique to Russia. Cost-effective energy-saving options are often neglected in other countries for various reasons. Many factors other than direct, quantifiable costs affect consumer decisions. These include lack of information, technical personnel and investment funds. Other barriers are uncertainty about energy prices, equipment performance and problems of equipment-supply infrastructure. Then there is simple aversion to change. Most customers are interested in comfort, quality and availability as well as by possible technological achievements.

What is special in Russia, however, is a near-complete lack of experience with market-oriented decisions on energy use. Old norms for thermal protection were flawed, with little control of actual performance. Industrial equipment was chosen because it was available and because it would cut energy costs. Appliances and cars were built from antiquated designs incorporating few of the modern features that improve energy efficiency. With unrealistically low energy prices, few users complained, or even noticed. It is important now not to consider energy use and efficiency in their sectoral and social contexts. Energy is an input to manufacturing, agriculture, transport and household comfort. It has to be considered on its merits within each sector. In this way, some Western governments have made more progress in stimulating improvements than markets alone would have yielded.

Russia's energy-efficiency gap diminishes competitiveness by reducing productivity. It leads to inefficient consumption of capital and energy resources. The *Main Provisions* estimate that about 20% of Russia's energy-efficiency potential per year may be implemented at $15 per tonne of coal equivalent. The most costly activities, costing over $60 per tonne, account for only about 15% of the potential. Implementing the bulk of available measures, which account for the remaining 65% of the potential and cost between $15 and $60 per tonne, will require dedicated investment of $7 billion to $17 billion from now to 2010 and another $25 billion to $50 billion in the period to 2020.

Over the last five years, despite legislative interest in supporting and promoting investment in energy efficiency, few successes have emerged. The factors hampering success include:

- lack of enforceability of contracts and non-payment of energy bills;
- an unstable investment climate;
- the small size of Russian energy-efficiency projects;
- lack of trained experts to develop bankable project proposals;
- the outdated structure of building and district heating-supply systems;
- lack of consumer-operated controls to regulate heating;
- lack of homeowner responsibility for repairs.

The Need for a Stable Investment Environment

The lack of private and public finance is a key problem. Investors need greater stability and reduced fiscal and legal risks. The PSA approach could be applied to energy-efficiency investments. The PSA is a mutually binding contractual agreement not subject to unilateral change. Its terms are negotiated between the government and the investor for the life of the project. PSAs could help minimise many of the risks that scare potential investors away from energy-efficiency or environmental energy service companies (ESCOs).

Until the barriers to investment fall, efficiency improvements will make little progress, despite Russia's huge potential and the likely profitability of many of these undertakings. Although many efficiency-improvement projects have short payback periods and bear practically no technological risk, the risk of non-payment, even by government organisations and enterprises, remains high. Official payment guarantees would lessen this risk. They are critical for investments in the form of energy contracts, a variation of the ESCO.[159] In this respect, an important breakthrough came with a provision in the Chelyabinsk regional law, which stipulates that:

- the return on investment in an energy contract is guaranteed by assurances from relevant administrations to pay for the work from the budget for fuel and energy purchases;
- further assurances will be provided by an agreement between the relevant administration and the regional energy efficiency fund.

This mechanism, whose success will of course depend on the reliability and creditworthiness of the regional administrations, could become a more effective tool than tax credits or exemptions. No practical example of its application yet exists, even for small-scale projects due to the inability of *oblast* and city administrations to balance their budgets. Large projects would present even bigger problems, because they would require sovereign guarantees from the Ministry of Finance.

Another important breakthrough came with a provision in the Tula regional energy efficiency law for a statutory budget item to finance energy-conservation. The law separated out the following special budget lines:

- heat-supply subsidies for residents;
- expenditures for energy and water in public buildings;
- expenditures for reconstruction of heat-supply systems for the coming winter;
- expenditures for street lighting.

The law provides for the evaluation of budget savings from energy-efficiency programmes. It also highlights the difficulties in setting a baseline by which to evaluate projects and policies, in verifying project results and in sharing the benefits from energy savings among the city, the oblast and the lender. Problems arose in 1997 in six Russian cities included in the World Bank's Enterprise Housing Divestiture Project. It was hard to determine what energy savings had been achieved by the project activities. Instead of using the savings to repay the World Bank loan, regional governments simply credited them to their own budgets.

159. These mechanisms are agreements between customers and contractors, under which the customers entrust the contractors with some energy-conservation work and pay for it from fuel and energy savings.

The Federal Government Decree No. 588 of June 1998, "On Additional Measures to Stimulate Energy Conservation in Russia", keeps energy-supply allocations constant for the payback period plus one year at federal facilities that implement efficiency projects. This tends to promote projects with long-term paybacks, but it also defines the basis for loan repayment tied to the project. If this idea is repeated in regional laws, a measure of stability will be achieved that would encourage ESCO-type contracts, as well as loans for efficiency-improvement projects.

The Kyoto Protocol offers several ways to enhance the attractiveness of efficiency investments in Russia. One Kyoto mechanism opens the possibility of reducing greenhouse-gas (GHG) emissions in one Annex I Party and counting it toward compliance in another Annex I Party. Authorised legal entities, including local governments and the private sector may participate. International greenhouse-gas emissions trading can also contribute to lower overall abatement costs.

►►► ***Providing stable investment frameworks could help attract efficiency investments.*** *Measures such as Government Decree No. 588 provide incentive and security for energy-efficiency investments at state-funded facilities. Unless energy-supply allocations are maintained until a return on investment is realised, state-funded enterprises and administrations have little incentive to undertake efficiency investments. Other mechanisms to stimulate private investors, such as PSAs, also need to be considered.*

ENERGY EFFICIENCY: A REGIONAL APPROACH

A regional approach to energy efficiency is essential because the energy situation differs radically among regions. Regions vary in their natural resource endowments, their distance from the main distribution networks and their consumption patterns. Energy intensity varies widely across regions. Reducing energy use is gaining increasing favour as a way to reduce regional expenditures, and release budget revenues for other purposes. It is seen as a way to increase industrial competitiveness, boost fuel exports and export revenues, reduce pollution and improve the comfort, health and safety of citizens. Inadequate tax collection, energy subsidies and the high costs of taking over social-welfare services from former state enterprises combine to produce a tremendous strain on local budgets. Heat and power subsidies alone absorb between 25% and 40% of some oblast budgets. Facing all these pressures, Russia's regional administrations have worked since 1995 to develop legal, regulatory and institutional frameworks for energy-efficiency actions.

By mid-2000, 33 regions out of 89 had energy-efficiency laws in place and 13 more were drafting them. Among the 89 jurisdictions of the Russian Federation, some have made substantial progress, while others have developed no energy-efficiency policies at all. Yet all regions can boast at least some activities. Individual companies and municipalities have taken initiatives or collaborated on federal projects, such as Energy Efficiency Demonstration Zones. Others participate in joint activities with foreign partners like the World Bank, the USAID Commodity Import Program and several EU energy-centre activities. These are very important in building local capabilities and solving specific problems.

Information programmes can motivate and create awareness, explain conservation opportunities and methods, improve technical skills and publicise effective programs. Lack of information results in uncertainties, risks and missed opportunities. Companies and administrations often work on projects "in the dark" – making no use of the experience, contacts or databases developed in similar projects elsewhere. This handicap can be remedied.

►►► ***Regionally based sectoral programmes should be encouraged.*** *Improving legal and institutional frameworks is critical for regions to begin initiatives by themselves, to identify necessary financing and to attract potential investors in the projects.*

10. ENERGY AND ENVIRONMENT[160]

EXECUTIVE SUMMARY

Environmental Impact of Energy Production and Use

According to Russian data, the energy sector produces up to 91% of man-made greenhouse gas emissions, about half of all harmful emissions into the air and 30% of all harmful discharges into water. Although such emissions declined in absolute terms over the 1990s, they did not fall as fast as GDP, despite air-management efforts and fuel switching to natural gas, which came to account for half of TPES. At the same time, the threat of increased emissions in future grew with the increased relative importance of heavy and energy-intensive industries, ageing capital stock, lack of investment and systemic inefficiencies in energy consumption. Inefficiencies stemmed from low energy prices, a lack of metering and controls, defects in markets and market discipline and industry's continuing orientation to meeting production goals.

Environmental Policy Instruments and Policy Implementation

A number of recent laws, regulations and official declarations set forth Russia's environmental policy goals. The 1991 Law on Environmental Protection seeks to achieve a balance between economic development and environmental protection, using fees[161] for pollutant emissions as the main economic instrument. This system, effective in the early 1990s, lost much of its force when the fees failed to keep pace with rapid inflation. Russia's broad socio-economic decline and budgetary shortages limited implementation of environmental policies and investment in environmental protection during the 1990s. With the current outlook for stronger economic growth, more effective implementation and funding will become possible – and critical, if the country is to limit the environmental damage of heavier resource use to meet increased energy demand.

Government Reorganisation and Regulatory Streamlining

The low priority given to the environment by the federal government has seriously impeded progress. Federal bodies dealing with natural resources and the environment have undergone several reorganisations and remain fragmented. The environmental regulatory framework, often complex, prescriptive and difficult to implement, leaves much room for discretionary decisions by the federal as well as regional and local administrations. Presidential Decree No. 867 of 17 May 2000 on the Restructuring of the Ministry of Natural Resources to include the functions and mandate of the Committee on Ecology within the Ministry structure may help to streamline the bureaucracy and regulatory processes.

160. This chapter is drawn partly from the *Environmental Performance Review of Russia* published by the OECD in 1999, in which the IEA participated.
161. All polluting sources are subject to a base fee proportional to their emissions or discharges. Multipliers or "ecological coefficients" raise the per-unit charges if maximum levels are exceeded or under specific conditions, designated as environmental emergencies or disaster zones.

Outlook and Co-operation with the International Community

Russia is a signatory to most recent international treaties and conventions relating to energy and the environment. The government has often fulfilled these international commitments more thoroughly – as a result of economic decline – than it has enforced its domestic laws and regulations. Many Russians consider international commitments as a device for developing the frameworks necessary to implement domestic initiatives and programs. Under the Kyoto Protocol, Russia has committed itself to stabilise emissions of six greenhouse gases (GHGs) at 1990 levels by 2008-2012. Its very low levels of GHG emissions, directly due to the economic contraction of the 1990s, have opened opportunities for emissions trading (ET). With the outlook for economic growth, ET and Joint Implementation (JI) could help raise revenues and attract investment to improve energy efficiency, which is essential for Russia's energy security.

ENVIRONMENTAL IMPACT OF ENERGY PRODUCTION AND USE

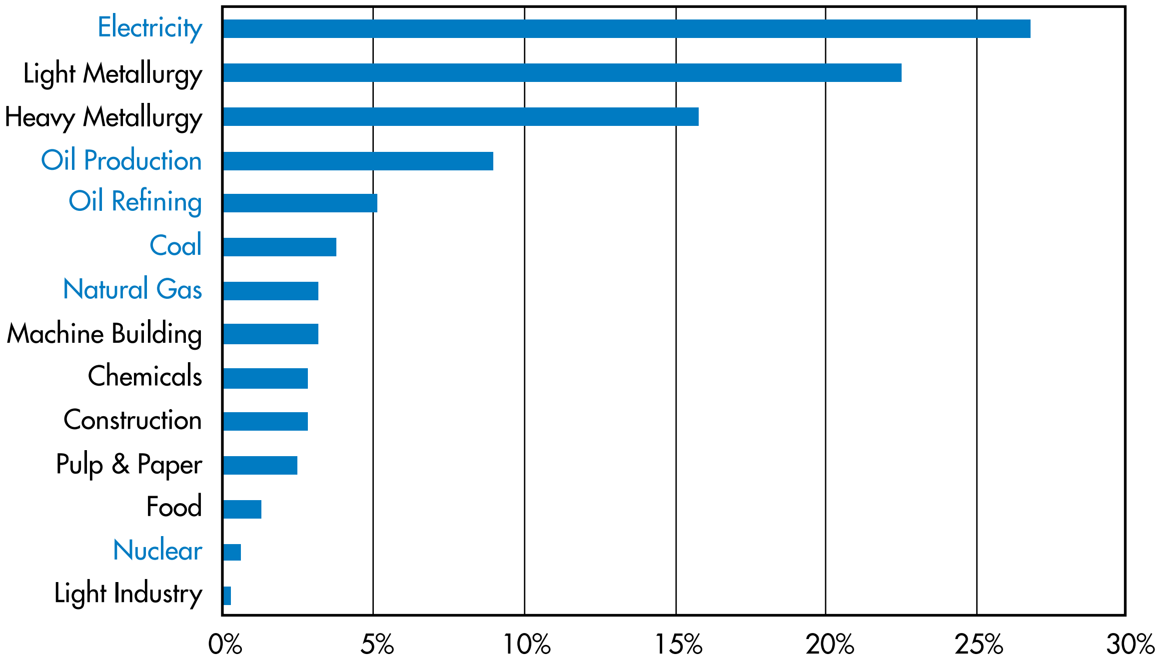
Russia took major steps toward environmental policy reforms during the 1990s, in parallel with the transition to a market economy and the devolution of powers to regional governments. Much more work is needed, especially with the outlook for economic growth and increased energy demand. The impact of energy production and use on the environment will increase unless major improvements are made in energy efficiency and environmental management. The 20% decline in GDP from 1993 to 1999 was matched by a similar drop in TPES. Energy intensity increased by less than 1%. Total emissions and effluents from the energy sector dropped about 30% – 13% on a per unit of GDP basis.

Atmospheric Emissions

The energy sector contributes up to 91% of man-made GHG emissions and about 50% of all harmful emissions to the atmosphere. Thus, one of the main priorities for energy policy and the Energy Strategy is reduction of the damage done by energy production and consumption to the environment. As Figure 23 shows, the electricity sector alone contributed 26.8% of harmful emissions in 1999. Upstream oil emissions are the next most harmful within the energy sector, with 9%. All other parts of the energy sector contribute less than 5% of emissions.

Total emissions of classic pollutants and CO_2 remain among the highest in the world. Emissions of SOx and CO_2 per unit of GDP are much higher than OECD averages. Emissions of conventional air pollutants from the energy sector decreased significantly in 1993-1999, due mainly to the economic downturn. However, as Table 10.1 shows, in some cases, emissions of SOx, NOx, particulates, CO, and VOCs decreased less than the decrease in production in each sector over the 1993 to 1999 period. In some cases emissions even increased. Thus, production decline and air-management efforts were more than offset by countervailing factors, including ageing capital stock, lack of investment and systemic inefficiencies in energy consumption. The inefficiencies stem, for example, from low energy prices, a lack of metering and controls, deficiencies in markets and market discipline and industry's continuing orientation to meeting production goals, as opposed to demand-side management.

Figure 23 Percentage Breakdown of Emissions* by Sector in 1999



** Emissions include: SOx, CO, NOx, Methane, VOCs and Particulate matter.*
Source: "State Report on the Ecology in 1999", Moscow 2000.

Air quality can be assessed against Maximum Allowable Concentrations (MACs), the very strict ambient quality standards in force in Russia. During the first half of the 1990s the MACs' long–term critical values were exceeded in 43 cities. One-third of the population lives in areas with high pollution peaks. In 16 cities, annual SO_2 concentration exceeded the MAC. The main sources of SO_2 are power plants, industrial furnaces and metallurgical industries. In the mid-1990s, the annual concentration of NO_2 in 92 cities exceeded the MAC. Power plants, boilers, heating systems and the transport sector are important sources of NO_2. Particulate matter, as defined and measured in Russia, includes dust, ashes, soot, smog, sulphates and nitrates. The mean yearly concentration of particulate matter stood above the MAC for 92 cities, in 80% of which pollution was considered severe.

Overall, the concentration of particulate matter decreased by 12.2% between 1990 and 1995 to 152 micrograms per cubic meter. For carbon monoxide concentration the MAC was exceeded in 22 cities. For benzo-a-pyrene, a carcinogenic substance emitted by metallurgical and power plants and heavy-duty diesel trucks, concentration levels are higher than the World Health Organisation limit in 92 cities, in three of them more than ten-fold.

The share of unleaded gasoline increased from 27.6 % of total production in 1990 to 46.9% in 1995 and 96.2% in 2000. High-octane motor gasoline (AI-91 or higher) made up 13.2% of the total in 1990, 24.8% by 1995 and 41.4% in 2000. Low-sulphur

Table 10.1 Air Pollutant Emissions from the Russian Energy Sector (1993-1999) (in Thousand Tonnes)

	1993	1994	1995	1996	1997	1998	1999	1993-99
Oil sector emissions	**1,862**	**1,682**	**1,447**	**1,305**	**1,267**	**1,383**	**1,322**	**– 29%**
SOx	16	15	19	20	23	23	23	46%
CO	618	497	438	490	541	657	627	2%
NOx	17	16	17	18	21	22	24	39%
Methane	900	886	689	535	439	432	446	– 50%
VOCs	275	236	208	210	202	189	143	– 48%
Particulates	36	32	30	32	41	60	60	64%
Production (million tonnes)	**352**	**316**	**307**	**301**	**306**	**303**	**305**	**-13%**
Natural gas sector emissions	**717**	**717**	**706**	**541**	**450**	**425**	**453**	**– 37%**
SOx	47	47	47	48	48	51	61	30%
CO	248	241	206	200	216	204	213	– 14%
NOx	62	51	28	24	24	24	25	– 60%
Methane	221	207	404	249	145	132	140	– 37%
VOCs	136	168	18	17	13	5	7	– 95%
Particulates	4	4	5	4	5	8	8	93%
Production (bcm)	**618**	**604**	**595**	**601**	**571**	**591**	**591**	**– 4%**
Coal sector emissions	**376**	**661**	**620**	**542**	**487**	**467**	**555**	**48%**
SOx	56	55	50	42	33	26	20	– 63%
CO	63	67	64	62	50	42	34	– 45%
NOx	15	16	16	16	14	11	10	– 33%
Methane*	–	418	403	345	320	326	436	4%*
VOCs	97	0	0	0	0	0	0	– 100%
Particulates	109	105	86	77	69	61	54	– 50%
Production (million tonnes)	**285**	**273**	**263**	**257**	**245**	**232**	**249**	**– 13%**
Petroleum refining emissions	**1,182**	**997**	**899**	**842**	**810**	**762**	**740**	**– 37%**
SOx	197	181	159	144	148	134	136	– 31%
CO	87	64	59	59	49	50	47	– 46%
NOx	22	21	21	21	22	21	20	– 9%
Methane	276	228	209	171	80	78	102	– 63%
VOCs	589	494	441	438	502	469	427	– 27%
Particulates	11	10	11	9	10	9	7	– 34%
Throughput (million tonnes)	**219**	**181**	**180**	**176**	**178**	**163**	**169**	**– 23%**
Electricity sector emissions	**5,890**	**5,234**	**4,977**	**4,707**	**4,386**	**4,303**	**3,891**	**– 34%**
SOx	2,498	2,255	2,134	2,006	1,833	1,818	1,618	– 35%
CO	191	219	248	259	254	238	242	27%
NOx	1,384	1,200	1,137	1,109	1,055	1,021	961	– 31%
Methane	3	4	4	3	4	6	3	23%
VOCs	1	1	1	1	1	1	1	30%
Particulates	1,813	1,556	1,453	1,330	1,239	1,219	1,065	– 41%
Production (TWh)	**957**	**876**	**860**	**847**	**834**	**827**	**846**	**– 12%**
Total energy sector emissions	**10,027**	**9,291**	**8,649**	**7,937**	**7,400**	**7,339**	**6,962**	**– 31%**
SOx	2,813	2,553	2,408	2,259	2,084	2,051	1,858	– 34%
CO	1,206	1,088	1,015	1,070	1,110	1,191	1,163	– 4%
NOx	1,501	1,304	1,218	1,187	1,135	1,100	1,041	– 31%
Methane	1,437	1,742	1,710	1,302	988	974	1,126	– 22%
VOCs	1,097	899	713	666	718	665	579	– 47%
Particulates	1,973	1,707	1,585	1,453	1,364	1,357	1,195	– 39%

** Comparison of coal sector emissions of methane is for 1994-1999.*
Source: "State Report on the Ecology in 1999", Moscow 2000.

diesel (with 0.2% sulphur content or less) went from 55.8% of total diesel production in 1990 to 71.0% in 1995 and about 85% in 2000. Production of ultra-low sulphur-content diesel (with 0.05 to 0.1% sulphur) began only in 1995, when it amounted to

3.85% of total diesel production. It rose to 10.7% by 1997 and an estimated 15% or less in 2000. Although private car ownership per capita, or about 128 per thousand, remains far below OECD averages, the number of cars more than doubled in the 1990s and is estimated to have reached almost 20 million in 2000.[162]

►►► ***With the outlook for stronger economic growth, improvement in air management and transport systems is essential.*** *This could include improvements in air management systems by aligning air quality standards with international ones and simplifying permitting and focusing on large pollution sources. Transport improvements could be provided through enhanced public transport systems and the use of physical planning instruments and clean air plans at the municipal level.*

Water Management

The energy sector as a whole contributes about 30% of all harmful discharges into water in Russia. As Figure 24 shows, the electricity sector alone contributed over 15% in 1999. The coal sector is the next most harmful with about 6%. All other parts of the energy sector contribute less than 5% each of absolute discharges. Locally, the most negative environmental effects come from oil and oil-product spills resulting from pipeline and tank leaks and ruptures. Annual increases in ground, surface and soil pollution are regularly recorded in the landfill areas of energy enterprises.

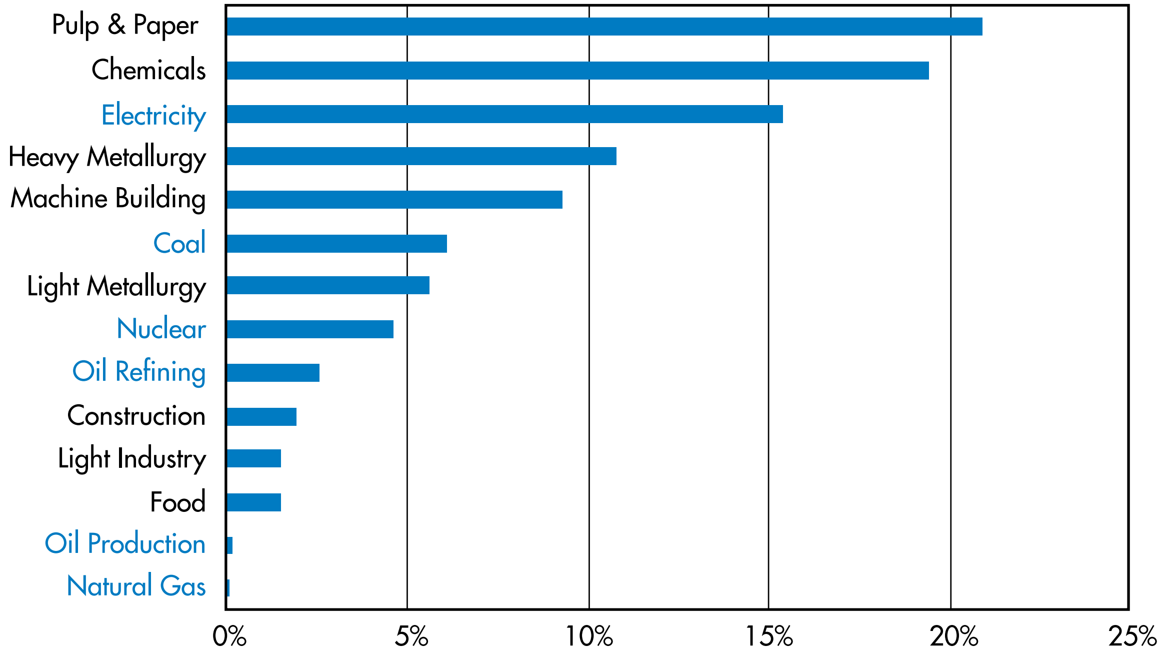
Over the 1990s, the volumes of water consumption and wastewater have dropped at least as much as, if not more than, energy production. But the general quality of water resources remains worrying. Industrial pre-treatment installations are too rare and those that exist are deteriorating. Since 1994, the energy sector has accounted for just under half of total discharges into the water, including untreated or insufficiently treated wastewater, treated wastewater and untreated cooling water. Federal reports estimate that the energy sector contributes over 25% of all wastewater discharges.

Water- and soil-polluting compounds discharged by the energy sector include crude oil, oil products, salt-containing waters from flue gas scrubbers and oil and water separators, corrosion inhibitors, paraffin sediments, chemical reactants, drilling wastewater and drilling sludge. Although total discharges of these toxic pollutants have decreased considerably since 1991, they remain too high.

The main Russian water-quality standards are based on chemical-biological parameters and health requirements. Under the national standards, most of Russia's rivers and lakes can be characterised as "moderately polluted" or "polluted". The most common surface-water contaminants include oil, phenol, easily oxidised organic substances, metal compounds, nitrates and nitrites. All the major rivers – the Volga, Don, Ob, Yenisey, Amur, Lena, Kuban and Pechora – are classified as "polluted" and their main tributaries – the Oka, Kama, Tom, Irtysh, Tobol, Miass, Iset, Tura and Ural – as "heavily polluted". Lakes and practically all reservoirs also contain significant pollution. Groundwater quality is generally better, but about 1,800 sites with polluted groundwater near major industrial and agricultural activities were identified in 1997, almost 80% of them in the European part of Russia.

162. See the section on Refined Product Consumption in the Oil Sector Chapter for more details.

Figure 24 Percentage Breakdown of Discharges into Water by Sector in 1999



Source: "State Report on the Ecology in 1999", Moscow 2000.

Major polluted groundwater conditions occur in the Moscow region, coal mining areas of the Tula region, the oil fields of the Tatarstan and Perm regions and major industrial centres such as Volgograd, Magnitogorsk and Kemerovo. Groundwater is contaminated mostly by sulphates, chlorides, nitrogen compounds, petroleum products, phenols and heavy metals. The Baltic Sea and Black Sea, the Sea of Azov and the Caspian Sea are polluted by oil and other hydrocarbons and synthetic surfactants, phenols and heavy metals. The situation in the Sea of Azov is especially bad. Extreme pollution, mainly by oil and oil products, is regularly observed in the White and Barents Seas as well as the Pacific Ocean, especially around Sakhalin Island and near Vladivostok.

►►► ***It is increasingly important to develop standards for waste and groundwater contamination from energy-related mining, drilling, processing and production.***

Waste Management

In 1999, industrial hazardous-waste generation amounted to 108 million tonnes, a 60% increase from 1993 (Table 10.2). Of this, 37 million tonnes were used at source by the generator and/or decontaminated. The fuel sector accounted for 11.5% of overall hazardous industrial wastes, the electricity sector for 8.1% and the chemical and petrochemical industry for 10.8%.

Over 90% of Russian hazardous waste is classified as Class 4 waste (including asbestos and phosphorus)[163] although mostly not classified as hazardous in OECD countries. Geographically, the Ural region accounts for 35% of total waste generation, with eastern, central and western Siberia accounting for about 12% each. The Ural region

163. The classification system used in Russia defines 140 generic waste types, subdivided into 4 hazard classes. Class 1 includes mercury, chlorine, chromium and galvanized production wastes; Class 2 includes oil products, arsenic and sulphuric acid, and Class 3 includes copper, lead and zinc.

is the predominant location for the chemical/petrochemical industry, which generates about 2/3 of Class 1 wastes.

Oil companies generated about 600 thousand tonnes of waste in 1999, much the same as in 1998. This stabilization is attributed to the inventorying of storage sites and the use of ecologically sounder drilling technology. About 110 thousand tonnes of hazardous waste were decontaminated, and 800 mud pits were recultivated in 1999. Serious ecological problems remain from past waste accumulations in storage areas and pits near the drilling wells.

►►► ***Uniform land disposal facility standards for various types of industrial waste (including hazardous waste, as appropriate) will help provide a basic level of environmental protection in the near term.*** *Such standards may also be applied in the analysis of existing waste sites.*

Table 10.2 Industrial Hazardous Wastes (Million Tonnes)

	1993	1994	1995	1996	1997	1998	1999
Total generated	67.52	75.11	89.92	82.59	89.34	107.06	108.07
Class 1	0.18	0.16	0.16	0.33	0.28	0.25	0.34
Class 2	1.60	1.58	2.22	1.91	2.17	2.33	2.80
Class 3	6.42	8.67	8.70	5.07	4.95	11.35	5.09
Class 4	59.32	64.70	78.85	75.28	81.99	93.12	99.83
Total recovery	27.13	32.09	33.99	44.52	39.12	42.17	37.16
Class 1	0.014	0.002	0.003	0.014	0.022	0.03	0.06
Class 2	0.43	0.06	0.55	0.48	0.80	1.00	1.17
Class 3	0.067	0.68	0.68	1.39	0.69	9.17	2.41
Class 4	26.02	30.75	32.72	42.63	37.59	31.98	33.52

Source: "State Report on the Ecology in 1999", Moscow 2000.

Arctic Zones and Resource Development

Recent Russian studies on the Arctic have identified areas with a high probability of environmental damage due to pollution of land, river and offshore ecosystems. The pollutants include heavy metals, petroleum products and organic compounds of different origin. The Kola, Severodvinsk, Norilsk and Sredne-Ob regions have been identified as "crisis areas", and the Timan-Pechora, Novaya Zemlya, Vorkuta and Pur-Nadym regions as "critical".

Oil Sector

Crude-oil output stabilised in 1995-1996 then increased in 1997 before the collapse in international oil prices and the 1998 financial crisis derailed recovery. Output recovered again in 1999 and 2000 under the impetus of high international crude prices and a decline in Russian production costs due to the rouble's devaluation. Although overall oil-sector emissions of pollutants into the air decreased about 29% from 1993 to 1999, the drop came mainly from lower methane and volatile organic-compound emissions. Emissions of SOx, CO, NOx and particulates actually *rose* by 46%, 2%, 39% and 64%, respectively. In 1999 CO accounted for 47% of total pollutant emissions from the oil sector, methane 34% and particulates 5%. Despite the doubling of filtering-device capacity in the oil sector in 1999, the wide dispersion of emission sources limited capture.

Official statistics of the Ministry of Energy report the volume of associated gas that is *flared* by oil companies was 7.2 Bcm in 1999 (or 20% of total associated gas production of 35.5 Bcm), with volumes ranging from a high of 10 Bcm (20%) in 1991 to a low of 4.3 Bcm (19%) in 1996. The Ministry reports that at most oil fields the necessary installations are in place to allow for the use of associated gas. Over the 1990s, about 80% of associated gas was "used" by oil companies and this is understood to mean "not flared". Table 10.3 below shows the wide divergence in the use or flaring of associated gas among different oil companies and locations. The figure for Yukos in Table 3 seems low when set against the recent statement by the company that it, alone, flared 70% of its associated gas in 1998[164]. Extrapolating this claim over the 35.5 Bcm of associated gas produced by Russian oil companies in 1999 would result in almost 25 Bcm flared. Experts in the field estimate that the volume of gas flared could be as high as 25 to 30 Bcm.

Despite the paucity of information on flared gas, the reasons *why* gas is flared is clear and has to do with the low flow rate and pressure of associated gas, the large distances to pipelines aggravated by the problems related to pipeline access and the low prices set by Gazprom and its subsidiary Sibur for sales by oil companies entering the gas-supply system. That so much associated gas gets flared, even at major oil fields with the infrastructure available to use it, demonstrates how high is the barrier posed by Gazprom's pricing policy. Investments such as those planned by Yukos to make use of 90% of its associated gas by 2004 to provide it with 2-3 Bcm per year of casing-head gas at an estimated cost of $25 million, to fuel co-generation plants, are a way for it to avoid this access issue. Although not a panacea, such investments do make economic sense and help reduce the damage to the environment and help reduce GHG emissions.

►►► ***Measures to reduce the flaring of associated gas by oil companies are essential to reduce harmful emissions to the atmosphere.*** *Oil companies should be encouraged to reduce the amount of flared gas. Better pipeline access and pricing policy would reduce harmful emissions, and the commercialisation of this gas would make economic sense.*

In 1999, the upstream oil sector reduced its consumption of water by almost 10% from the year before, mainly through increased use of re-circulated water for re-injection to maintain well pressure. Polluted wastewater discharges plunged by over 80%. To reduce discharges of oil and oil products into surface waters, oil companies continue to work on a system of monitoring oil wells. In 1996, over 7,500 abandoned wells were reported as needing repairs, 300 of them in serious need.

Heavy petroleum products dominate the Russian refinery output mix due to relatively unsophisticated nature of Russian refineries. This is out of line with domestic demand

164. "Yukos to start producing its own electric power" – http://www.gasandoil.com/goc/company/cnr04480.htm (11/2000)

Table 10.3 Flared Associated Natural Gas by Russian Oil Companies in 1999

Company (fields producing most associated gas)	Flared Associated Gas (in Bcm)	As a % of Total Associated Gas
Rosneft (Purneftegas fields)	.530	24%
Lukoil (Kogalimneftgas & Uraineftgas fields)	.416	17%
Yukos (Yuganskneftgas fields)	.338	26%
Surgutneftgas (Kaminsky, Tyansky fields)	.489	4%
Slavneft (Megionneftgas fields)	.082	10%
Sidanko (Varyeganneftgas fields)	.757	78%
Sibneft (Noyarbrskneftgas fields)	.270	17%
Gazprom (Urengoygasprom field)	.373	27%
Geoilbent (N. Gubinsky field)	.454	91%
TNK (NijnyVartovskneftgas)	.217	13%
TNK (Tyumenneftgas)	.062	79%
All other fields of oil companies	**3.2**	
Russian Total	**7.2**	**20%**

Source: "Fuel & Energy of Russia", A. M. Mastepanov, Ministry of Energy, 2000; Infotek #1, 2001.

for light products such as gasoline, diesel fuel and kerosene. As Russian prices for refined products continue to rise to world levels, the attraction of using crude oil to produce higher-value refined products will rise. At the same time, the incentive to streamline refinery capacity and to increase output of lighter products will help reduce the negative impact of refining on the environment. As Tables 1 and 2 show, the sector's emissions into the air and water declined in most cases in 1998-99, despite an increase in output. From 1993 to 1999, as refined-product output dropped more than 20%, most emissions indicators fell by even more. Despite this positive sign, ten accidents occurred at Russian refineries in 1999 and six of them reportedly caused environmental damage. The accidents involved emissions and spillage resulting from the depressurisation of product pipelines, pumps and reservoirs. Unsanctioned tapping into product pipelines, inducing rapid depressurisation, caused some of them.

Natural Gas Sector

While declining GDP caused production of other energy resources to drop sharply in the 1990s, natural-gas output eased by only about 10%, while the gas share in TPES increased to over 50%. Emissions into the atmosphere increased slightly. The main emissions from the natural-gas sector are methane – a greenhouse gas – CO, SOx and NOx. Much progress has been made in reducing emissions of NOx, which fell by almost 60% from 1993 to 1999 thanks to the modernisation of combustion chambers and replacement of gas compressor units at compressor stations.

Jointly with Germany's Ruhrgas AG, Gazprom has initiated a Joint Implementation project to improve long-distance gas transmission in Russia. The first stage of the project was completed at *Volgatransgaz*, covering six-line systems of gas mains totalling 5,000 km. This resulted in the reduction of annual fuel-gas consumption by 120 Million M^3/year and of carbon-dioxide emissions by 231,000 tonnes. If the project is extended as planned to other sections of Gazprom's pipeline system, the estimated savings will amount to 1.5 million tonnes of CO_2.

Scarce data on leakage and losses from the high-pressure transmission system and an almost complete absence of such data for the low-pressure distribution networks render analysis impossible. Estimates of leakage in distribution in 1998 reached at least five Bcm. Most distribution companies have had serious financial difficulties and have undertaken very little new investment. The lack of metering and measurement infrastructure in gas distribution compounds this problem.

►►► ***Investments in trunkline and distribution pipeline maintenance would reduce harmful emissions to the atmosphere.*** *Joint Implementation (JI) projects such as the Ruhrgas-Gazprom venture to improve long-distance natural gas transmission in Russia should be encouraged. Improved metering is essential. Additional consideration will need to be given for how finances from JI projects will be allocated.*

Pipelines[165]

With almost 50,000 km of trunk oil pipelines, 145,000 km of gas pipelines and over 20,000 km of oil-product pipelines crossing Russian territory and water basins, the soundness of these pipelines is a key concern for environmental safety. Oil and oil-product spills resulting from leaks and ruptures in pipelines and tanks present one of the greatest environmental problems in West Siberia, North-Caucasus, the Komi Republic, Bashkortastan and Tatarstan, as well as regions of the Middle and Lower Volga. As shown in Table 10.4, the number of registered accidents and leaks decreased from 1996 to 1999, but their frequency remains alarmingly high. Over 96% of the accidents in 1999 were attributed to pipe corrosion due to pipeline age. To prevent and lower the risk of pipeline leakage, the industry is undertaking more diagnosis and monitoring of pipelines and targeting parts in need of repair or replacement. Anticorrosive metals are increasingly used. By 1999, over 2,500 km of oil and water pipelines had been replaced. Yet in hearings before the Duma in June 1999, over 35% of industrial and trunk pipelines were identified as having exceeded their planned lifetimes. Over 30% of gas pipelines, 46% of oil pipelines and 25% of oil-product pipelines are more than 20 years old, and 5%, 25% and 34%, respectively, are over 30 years old. Thirty percent of accumulator pipelines are also more than 30 years old.

►►► ***Industry should be encouraged to continue and intensify its diagnosis and monitoring of pipelines, targeting parts in need of repair or replacement and use of anticorrosive metals.***

Table 10.4 Number of Pipeline Leaks and Accidents

	Overall Pipelines	Oil Pipelines
1996	35,313	23,525
1998	28,523	19,331
1999	27,408	19,227

Source: 1996: Ecology and Energy, Institute for Global Problems of Efficiency & Ecology, Moscow, 1996. 1998-1999: Report by Energodiagnostika Consulting for Ministry of Natural Resources, Moscow, 2001.

165. See the Oil and Natural Gas Sector Chapters for discussion and estimates of leaked volumes.

Coal Sector

The environmental impact of coal mining varies from mine to mine, with the older basins exerting a greater negative effect than newer ones. The newer open-pit mines, like those in the Kansk-Achinsk Basin, operate in line with international standards and practices. The major environmental concerns related to Russian coal mining include:

- water pollution through acid mine drainage from coals with high iron-sulphide content, especially in the *KiselUgol* mines in the Urals and *IntaUgol* in the Pechora Basin; and
- saline discharges, especially in the Chelyabinsk region, and to a lesser extent suspended solids from coal-washing plants, although this problem has decreased through improved water treatment practices;
- air pollution from coal mining has three main origins. The first is coal dust from surface mines; for example the 1995 estimate of annual coal dust from the huge Kuzbass mine was about 238 thousand tons. The second source of air pollution, estimated at 15 kg/tce, arises from coal transportation. The third is the spoil heaps near many of the larger mines. Smouldering heaps create localised air pollution problems in the Rostov area and the Donesk, Kuznets and Pechora basins.

From 1993 to 1999, emissions into the air and water from coal mining, except for methane, decreased much more rapidly than the rate of decline in coal production. The closures of uneconomic mines and increased concentration of coal production in mines better able to meet environmental- performance standards explain this effect. Emissions of methane, however, increased 4% from 418 million tonnes in 1994 to 436 million tonnes in 1999. The Russian coal industry has established a special ecological fund, EcoUgleFund, to develop technologies to improve the extraction and refining of methane. As uneconomic mines are closed and new mines are opened using advanced technologies, this trend should improve. Nevertheless, given the outlook for a 75% increase in coal production, major investments will be needed to reduce the harmful emissions from coal mining.

Although water consumed in the upstream coal sector decreased in the 1990s as a result of increased water recirculation, discharges into the water remain high. Only 80% of the coal companies have water-treatment plants, and most of these are ineffective. In 1996 over 70% of the overall volume of polluted wastewater got discharged without meeting ecological norms. Some 21% of the polluted water was discharged without any treatment whatsoever.[166]

By far the more detrimental air-pollution impact of coal comes from its use in thermal power stations and boilers with inadequate pollution-control systems and inefficient coal conversion. A reliable supply of high-quality coal with low sulphur content could help reduce the damage done by coal-fired electricity and heat generation. As is often the case in Russia, emission limits are just as strict or even stricter than international norms, but they are not strictly enforced. Environmental fines levied against companies with emissions in excess of allowable levels have not kept pace with inflation. So there is no economic incentive to invest in pollution-control systems. In 1996, there were virtually no SO_2 control systems fitted to existing power plants. Although particulate control systems exist, they are often inoperative.

166. *Ecology and Energy*. Institute for Global Problems of Energy Efficiency & Ecology (1996), Moscow.

►►► ***The environmental impact of coal mining, although slightly lower since the beginning of the 1990s, will increase significantly with increased coal production, unless major environmental investments are made.*** *Most urgently needed are investments in pollution-control systems and clean coal technology.*

Nuclear Sector

The potential impact of the Russian nuclear programme on the environment raises long-term concerns, particularly in neighbouring countries. The concerns reflect mainly Russia's poor reputation and past bad practices in radioactive-waste management. Examples include dumping radioactive waste at sea, pumping liquid radioactive waste underground and failing to give proper attention to the fleet of nuclear submarines. Some 300 reactors and 8,000 nuclear fuel elements, lie abandoned and rusting in the fjords of the Kola Peninsula.

The nuclear programme – including power plants, the nuclear fleet and other facilities, all belonging to different federal authorities – had accumulated by 1999 a nuclear waste stock with overall radioactivity of about 8.1×10^{19} Bq (2.2×10^{9} Ci). Spent fuel is not considered as waste in Russia; some 14,000 tons of irradiated nuclear fuel has been produced and stored in the nuclear power plants, naval storage facilities, research establishments and military nuclear facilities. It has an overall radioactivity of about 3.0×10^{20} Bq (8×10^{9} Ci).

Existing storage facilities for solid and liquid radioactive waste and irradiated nuclear fuel, commissioned 20-30 years ago as temporary storage sites, are filled almost to capacity, and their technical state is far from satisfactory relative to current safety standards. Available technological capacity does not ensure the processing and reliable insulation of already-collected and newly- generated radioactive waste and irradiated nuclear fuel. The scheduling of reconstruction or upgrades of older facilities and construction of new facilities does not keep up with current rates of production of nuclear wastes. In 2000, there was no full technological complex in Russia for reprocessing solid radioactive wastes or reducing their volume by incineration or compression or for transforming liquid wastes into forms suitable for transport and disposal.[167] Some Russian officials consider the situation to be rapidly deteriorating. They call for urgent measures, because most of these potential sources of radioactive pollution present a serious threat to the environment and public health.

The Government has responded by introducing a Federal Programme on Handling Radioactive Waste and Spent Nuclear Materials for 1996-2005. Adopted in 1995, it aims at establishing a legal and regulatory framework, developing appropriate technologies and constructing safe long-term storage and disposal facilities. In parallel with this programme, a total of 174 international projects to deal with radioactive-waste issues were under way in Russia in 1998, supported by EU funding exceeding €34 million and a US contribution of $20 million. Despite this international assistance, only limited progress has been made so far, due mainly to financial and institutional constraints on the Russian side.

Large amounts of collected and unseparated radioactive waste increase the risks of radioactive emergencies and pose a real threat of environmental contamination. This

167. *State Report on the Ecology in 1999*, Moscow 2000.

Imports of Spent Fuel

In August 2001, Russian President Vladimir Putin approved key legislation allowing the import and reprocessing of spent nuclear fuel. This legislation creates a legal framework for what MinAtom considers "highly profitable" business activities in which it estimates it could raise up to $20 billion. The law includes a list of nuclear wastes, which cannot be stored in, or brought into, Russia. The law is also intended to promote environmental security during transportation. MinAtom proposes to import 1,000 tonnes of spent fuel a year, roughly the amount currently produced by Russian plants and those in Ukraine, which already sends fuel for reprocessing. National and international controversy regarding these plans shows clearly what Russia needs to do before offering any nuclear fuel-handling services to foreign customers.

speaks strongly against MinAtom's recent initiative to permit commercial imports of spent nuclear fuel.

►►► ***Russia will need to ensure the safe handling of already-collected radioactive wastes and irradiated nuclear fuel.*** *It is all the more important if Russia hopes to gain credibility and public acceptance for MinAtom's recent plans to permit commercial imports of spent nuclear fuel. As a matter of urgency, it must first clean up all its contaminated sites and assure the safe long-term storage of domestic spent fuel and radioactive waste. Only when this has been done will it be appropriate – and will the international community be confident enough – to import and treat fuels from other countries.*

Electricity Sector

The electricity sector is by far the heaviest emitter of pollutants to the Russian atmosphere. It contributed 26.8% of the total in 1999, although emissions fell almost 10% from 1998 despite a slight increase of about 2% in electricity production. This continued a declining trend in evidence since 1993. A 33% drop in emissions from 1993 to 1999 was made possible by falling electricity production and an increasing share of natural gas in the thermal-fuel mix. Yet 1999 was a turning point as electricity demand increased for the first time in the 1990s. Nuclear power met most of the increased demand, increasing its share from 12.5% in 1998 to 14.4% in 1999. This limited the increase in pollutant emissions. The Ministry of Energy also points to the pollution-abatement measures undertaken in 1999, under which 16 thermal plants were equipped with more efficient ash-catching devices and 17 boiler stations with NOx-reducing equipment. Five thermal stations were retrofitted to burn natural gas. These measures reduced emissions of ash by an estimated 6,600 tonnes, NOx emissions by 1,500 tonnes, and SOx emissions by 2,100 tonnes.

It is encouraging to see positive steps to reduce emissions in the electricity sector. With the outlook for increased electricity demand, such measures must continue and expand. This has special importance in view of the government's intention to reduce the share of natural gas in the thermal electricity fuel mix from 63% in 1999 to 51% in 2020, with the coal share gaining from 24% to 44%. Table 10.5 presents the results of a study[168] to assess the impact on emissions of CO_2, SO_2, NOx and ash from increased

168. This study assumes the extrapolation of current technical and emissions standards for coal.

use of coal in electricity and heat generation. The study took into consideration statements by Gazprom calling for the reduction of natural gas deliveries to UES by up to 30 Bcm by 2002. It assessed two alternative scenarios:

- replacing 30 Bcm of natural gas with 66 Mt of brown coal from the Kansko-Achinsk basin;
- replacing the same 30 Bcm of gas with 56 Mt of coal, 50% of it brown coal from the Kansko-Achinsk basin and 50% hard coal from the Kuznets basin.

Both scenarios assume that the power plants will be equipped with ash-catching devices. The results show a doubling of CO_2 emissions, an increase of 48-58 Mt, and 3-6 times more NOx, not to mention positive levels of SO_2 and ash, which are non-existent in natural-gas use.

Table 10.5 Comparison of Emissions for Electricity Generation: Coal vs. Natural Gas

Fuel	Annual Volume of Emissions – Million Tonnes				
	CO_2	SO_2	NOx	Flying ash	Captured ash and waste
30 Bcm Natural gas	56.2	–	0.044	–	–
Gas replaced by 66 Mt of Kansko-Achinsk brown coal	114	0.26	0.15	0.029	2.87
Gas replaced by 56 Mt, half hard coal, half brown coal	104	0.305	0.26	0.056	5.49

Source: D. A. Krylov and V.E. Putintseva, (2000), PodzemGazprom, Moscow, Institute for the Safe Development of Nuclear Energy, Russian Academy of Science.

►►► ***Major investments in environmental protection and clean-coal technology will be needed, given the projected increase in coal production for electricity and heat generation.*** *Coal mining usually generates a great deal of air and water pollution. Using coal in electric power stations and boilers with inadequate pollution-control systems and inefficient coal conversion has a still greater detrimental air-pollution impact. Hence, major environmental investments will be needed to deal in a sustainable way with increased coal consumption.*

ENVIRONMENTAL POLICY INSTRUMENTS AND POLICY IMPLEMENTATION

A number of laws, regulations and official declarations set forth Russia's environmental policy goals. The 1991 Law on Environmental Protection seeks to achieve a balance between economic development and environmental protection. It applies quality standards and establishes environmental requirements for economic activities as well as mechanisms for their implementation. Separate laws address air, water, fauna, forests and the State Ecological Examination. Sectoral or semi-specific statutes include provisions that may duplicate or even contradict the Law on Environmental Protection. International environmental agreements serve as an important source of national policy goals and laws, because their provisions take precedence over federal law. Some regions have established progressive environmental policies, sometimes based on regional legislation and more or less tied to economic and fiscal mechanisms. The approaches used and results achieved in different regions vary widely.

A comprehensive system of environmental quality standards forms the basis for granting permits and setting fees. The most important are the Maximum Allowable Concentrations (MACs), which establish maximum values for peak and average concentrations of environmental pollutants. MACs include 479 standards for air pollutants, 2,679 for water pollutants and 109 for soil pollutants. They are often based on medical requirements and thus are very severe. The Government sets Maximum Permissible Emissions (MPEs) based on MACs for enterprises, municipal treatment facilities and other stationary sources of pollution. Standards have also been set for concentrations of harmful substances in emissions from mobile sources. To reflect current technical and economic limitations, less strict Temporarily Permitted Concentrations (TPCs) and Emissions (TPEs) are used as an intermediate step in meeting the stricter MPEs.

Economic Instruments

The main economic instrument of environmental policy is the imposition of fees for pollutant emissions and discharges. All polluting sources are subject to a base fee proportional to their emissions or discharges. Multipliers or "ecological coefficients" raise the per-unit charges under specific conditions, designated as environmental emergencies or disaster zones. When emissions exceed the MPEs but are below the TPEs, the base charge is multiplied by five; when they exceed TPEs, the multiplier is 25. With the concurrence of federal and regional environmental authorities, enterprises may deduct from their emission charges all or part of the value of environmental improvements made at their own expense. This offset provision is a critical component of the pollution-charges system. Offsets in some regions (especially the most economically depressed) may exceed cash transfers, and they play an important role even in comparatively well-off regions. For example, of some 65 million roubles in pollution charges due in the Rostov region in 1997, offsets amounted to slightly more than 20 million roubles.

Pollution charges provide about 85% of the income of Russia's environmental funds, the remainder coming from fines, damage compensation payments and interest. The Federal Environmental Fund (FEF), regional funds and local funds receive 10%, 30% and 60%, respectively, of the revenue from pollution charges. Environmental funds eke out increasingly tight government and company budgets. Between 1992 and 1997, these funds collected about $2.2 billion.

The fee system, which was very effective in the early 1990s, has lost much of its incentive effect due to rapid inflation. The main purpose of the current system appears to be to raise revenue. In principle, indexing emission charges should ensure that it is more expensive to pollute than to comply. But, although the fees are revised regularly, they have failed to keep pace with inflation. Between 1990 and 1996, the real worth of pollution charges decreased by a factor of 20. For some of the more prosperous companies, especially oil refineries, pollution fees are so low as to be insignificant; for others, like uneconomic coal mines that sustain heavy losses, the charges will remain unpaid no matter how low they are.

►►► ***Pollution fees must be indexed to inflation and fiscal discipline improved.*** *To provide an incentive to reduce emissions, pollution fees must keep up with inflation. The practice of treating environmental investments as offsets against pollution charges requires more oversight and greater transparency. Phasing out these offsets would contribute to the establishment of fiscal discipline and the rule of law.*

Pressures have grown since 1995 to "consolidate" the environmental funds by incorporating the revenues in governmental budgets, although with some degree of earmarking to preserve their environmental nature. While the 1991 Law requires that environmental funds be independently managed and specifies that "spending of resources for non-environmental purposes shall be prohibited", the annual federal budget law has included the FEF as a line item since 1995, and regional authorities have received recommendations to do likewise. The operational significance of this is unclear. In 1998, pressure re-emerged to consolidate the FEF as part of a general effort to reduce autonomous budgetary accounts. The issue will probably be resolved soon as part of the remaining work on Part II of the Tax Code.

Economic instruments could serve to enhance environmental policy implementation. Charges and penalties for environmentally harmful products or technologies have been proposed for inclusion in Part II of the Tax Code. Suggestions include charges on ozone-depleting substances, leaded gasoline, pesticides and mineral fertilisers as well as, possibly, CO_2 emissions. Such charges would go beyond the system of pollution fees. Before introducing them it is important to ensure that consumers pay energy prices that reflect all costs.[169] The proposals encountered serious resistance in light of the financial difficulties of many polluting enterprises.

►►► ***Energy pricing, pollution charges and taxes could be used more widely.*** *Proposals to use economic instruments such as pollution charges or taxes to reduce harmful emissions should be carefully examined. The 1998 Law on Fees for Use of Water Bodies is a good example of charging for the use of resources. It is important in developing such charges to seek to accurately reflect cost of externalities in the price.*

Environmental Expenditure

Environmental expenditure includes pollution abatement and control as well as protection of nature and the water supply. Overall environmental expenditure was estimated at 2.2% of GDP in 1997, with 1.7% of GDP going towards pollution abatement and control. This amounted to about 46 billion roubles ($8 billion). These estimates include both monetary and offset expenditures. The main sources of financing of environmental investment are industry (more than 60%) and environmental funds (17%). Foreign sources provided just over 7% in 1997. Federal expenditures budgeted through the Ministry of Natural Resources represent only a small percentage. Total outlays are low compared with those in many other countries.

The role of the environmental funds has diminished with the drop in non-indexed revenues from environmental charges. Regional and local bodies still consider them highly useful sources of finance. Co-ordination among the various regional and local funds and relations with the FEF in Moscow have been inadequate.

169. For example, leaded gasoline is still cheaper than unleaded gasoline in many parts of Russia.

►►► ***The status and co-ordination of environmental funds need clarification.*** *Inconsistencies between the Law on Environmental Protection and new taxation laws should be addressed. Better co-ordination among funds and economic assessment of the environmental effect of funding could help to increase their efficiency.*

GOVERNMENT REORGANIZATION AND REGULATORY STREAMLINING

The Executive Branch of the Russian Government underwent major changes in 2000, which are significant for environmental protection. Presidential Decree No. 867 of 17 May 2000 and Russian Federation Government Resolution No. 495 of 6 July 2000 restructured the Ministry of Natural Resources (MNR). The inclusion of the functions and mandate of the Committee on Ecology within the Ministry structure initially met with apprehension. Subsequent developments, however, reflect a framework, which maintains the mandate of the former Committee. The reorganisation increasingly appears to be part of the wider reforms championed by President Putin to streamline bureaucracy and the government regulatory process. One of its aspects, which could encourage investment, streamlines related functions within one Ministry.

Regulatory Streamlining

With progress in improving the fiscal and legal framework for investment in the upstream oil and gas sectors, it becomes increasingly important to clarify, streamline and make less prescriptive the regulatory decision-making process. A stable investment regime does *not* need:

- an unreasonable number of complex regulations;
- uncertainty about who the regulators are, their mandate and who is in charge in a particular situation;
- uncertainty about the legal status of regulations, particularly older versions;
- regulations that quickly become dated but nevertheless remain in force;
- conflicts over legal interpretation due to poorly written regulations;
- cumbersome and lengthy processes for obtaining approvals and permits.

Excessive prescriptiveness discourages technological innovation, the "driver" of progress and industry. Furthermore, no value accrues from imposing regulations that the regulated party cannot meet for either technological or economic reasons, or that diverge widely from international norms. Industry has an interest in taking responsibility for health, safety and the environment, because a poor record on this score reduces a company's standing in the community where it operates and internationally. In general, multinational investors will be most comfortable with generally accepted international rules and standards, which they consider to have been tested and proved effective. Such rules and standards reassure investors and help them predict costs and financial risks.

►►► ***Regulatory regimes tend to be more effective when goal-oriented instead of prescriptive.*** *Experience in countries like Norway, Canada and the US shows that regulations that set goals and objectives work well. Major investment projects in Russia will work better if industry is told "what" needs to be done and is left to accomplish the "how" by itself.* It is also critical to enforce existing standards, which are often adequate.

These principles have been the focus of much work in Russia by interdepartmental working groups headed by the Ministry of Energy. The RUNARC project (Russia/U.S.A./Norway Arctic Offshore Oil and Gas Regime) made extensive recommendations along these lines in its Feasibility Study Report (FSR) of December 1998. After an exhaustive analysis of the current regulatory and legislative regime, the FSR states the following key points and conclusions:[170]

- russia's current environmental and safety regime is a largely outdated and complicated system of laws, normative documents, and regulations, which exhibit numerous gaps, overlaps and a mix of out-of-date or misapplied Soviet regulations. The regime contributes to numerous contradictions and conflicts of interest between operators, regulators, and the public;
- a radical revision of Russia's offshore regulatory regime is needed. The revised regime will be based on a new concept and organisational structure;
- the new regulatory regime will be developed during a four-to-five year transition period that will allow offshore projects already underway or in the late planning stages to continue;
- special legislation and other normative acts and documents will support the new system. They will be clear and consistently applied, creating a stable investment climate and protecting the environment and the health of local populations.

►►► ***Regulatory streamlining is necessary to ensure effective implementation of projects.*** *Initiatives already underway, to streamline bureaucratic procedures, as well as those reflected in "Russia's Development Strategy to 2010" should be encouraged. Russia needs clear, consistent and transparent regulations to attract the necessary investment to develop its natural resources effectively while safeguarding the environment.*

OUTLOOK AND CO-OPERATION WITH THE INTERNATIONAL COMMUNITY

The *Main Provisions of the Russian Energy Strategy* place relatively little emphasis on environmental issues. Only a short section on the Scientific, Technical and Ecological Policies of the Strategy focuses on the development of technologies and the technical means for the stable long-term development of energy resources, ensuring ecological and technological safety of energy production and use. It lists some general goals:

170. Description of the RUNARC FSR and goals can be found at http://www.acib.uaa.alaska.edu/arc/NEWS.htm "Changes to the Ministry of Natural Resources – an Offshore Perspective" by Dennis Thurston and Brad Laubach, U.S. Minerals Management Service, January 2001.

- ecologically clean coal-fired power stations;
- safety of existing nuclear stations as well as the creation of the new generation of fast neutron reactors;
- efficient technologies based on traditional and renewable energy sources as well as new non-traditional sources, such as gas hydrates, heavy oils and bituminous substances and coal-field methane;
- mass production of energy-saving equipment;
- small-scale energy stations for hydro-energy resources, solar, wind and geo-thermal energy and other renewable sources;
- the enhanced sophistication of refinery runs to ensure higher-quality refined products; and
- the development and implementation of standards for the rational use of fuel and energy.

►►► ***Major improvements in energy efficiency are needed to ensure Russia's energy security.*** *Given the outlook for continued economic growth, priority should be given to energy efficiency gains which are likely the most economic and essential to meet increasing energy demand. Effective energy price reform would provide the necessary basis to attract needed investment and provide the necessary incentives to achieve energy efficiency targets.*

Commitments under the Kyoto Protocol

In 1998, Russia was still the third largest emitter of energy-related CO_2, with 1,416 Mt, accounting for 6.3% of the world total despite a 40% drop in these emissions since 1990. Energy production and consumption of fossil fuels account for 91% of Russia's man-made CO_2 emissions. Carbon intensity in 1998 was 3.4% above 1990, at 2.13 kg CO_2 per unit of GDP in 1990 dollars. Although this represented a decline from 1996 levels, it was still almost 3.5 times the OECD average – a result of the high energy intensity of the economy rather than the carbon intensity of its fuel mix, of which more than half consisted of natural gas (53% of TPES) and non-fossil fuels (9%).

As an Annex I party to the UN Framework Convention on Climate Change (UNFCCC) (1992), Russia has agreed:

- to carry out an inventory of GHG emissions and sinks;
- to implement national policies limiting anthropogenic GHG emissions and to increase sinks and reservoirs, with the aim of reducing emissions to their 1990 level by 2000;
- to assess the environmental and economic consequences of climate change.

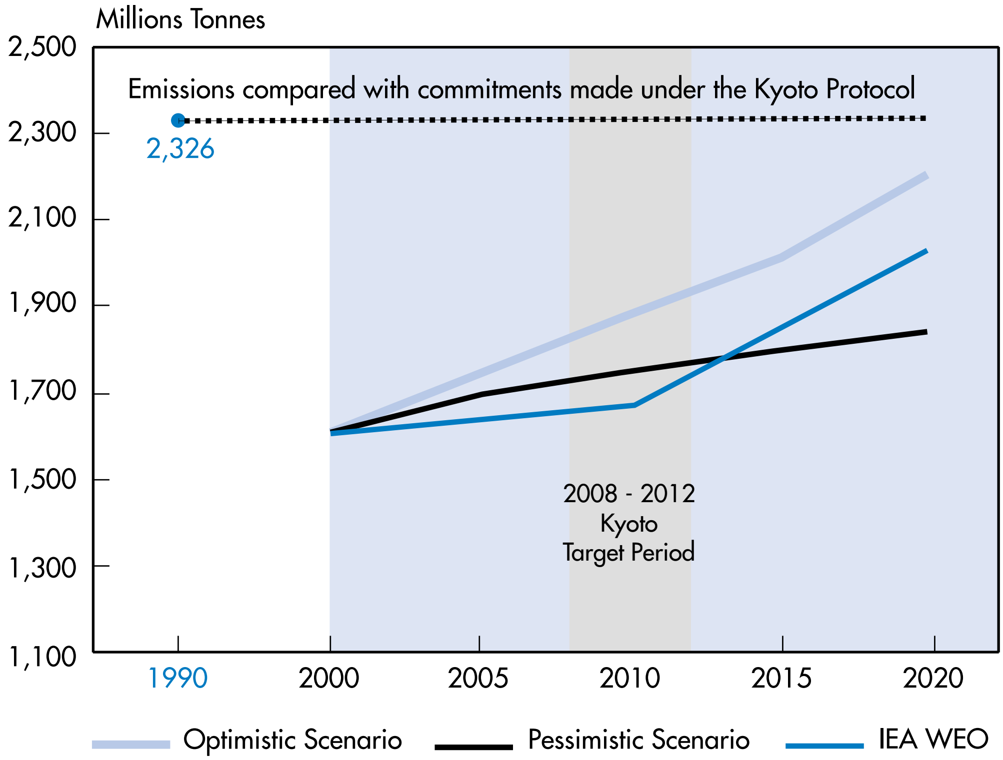
Under the Kyoto Protocol of 1997, Russia is committed to stabilise emissions of six greenhouse gases at 1990 levels between 2008 and 2012. The Kyoto Protocol provides three "market" mechanisms – Joint Implementation, Emissions Trading and the Clean Development Mechanism – that countries can use to co-operate on reaching their emissions reduction targets.

Russia estimates its overall GHG emissions in 1990 at 3,039 Mt of CO_2 equivalent. Over 85%, or 2,326 Mt consisted of CO_2. The energy sector contributed about 90%

of that. As shown in Figure 25, the Ministry of Energy projects a 16% increase in energy-related CO_2 emissions by 2010 and a 37% increase by 2020, under an optimistic scenario for economic growth, price reform and energy-efficiency improvements. The expected level of CO_2 in 2008-2012 will thus fall well below that in 1990.

At the time these commitments were made, the Russian energy outlook foresaw natural gas maintaining its 53% share of TPES to 2010. The current outlook sees natural-gas consumption dropping to 42-45% in 2020 with a consequent increase in coal's share from 20% to 23%. This raises concerns about future GHG emission projections. As indicated in Figure 25, and despite the new outlook, emissions are expected to stay well beneath the Kyoto emission targets. This latest projection from the Ministry of Energy assumes major improvements in energy efficiency.

Figure 25 Russian and IEA Projections of CO_2 Emissions in Line with the Kyoto Protocol



Source: based on "Main Provisions of the Russian Energy Strategy to 2020", November 2000.

The IEA's World Energy Outlook: 2000 (*WEO 2000*) projects a 1.1% growth rate for Russian CO_2 emissions from 1997 to 2010 and an overall growth rate of 1.5% for 1997-2020. These projections largely track those of the Ministry of Energy, despite the fact that they are based on a GDP growth-rate assumption of 2.9%, about half that assumed in the Russian Energy Strategy. The reason for this apparent anomaly lies in the more ambitious Russian outlook for energy efficiency, with expected improvements of between 2.8% and 4% per year on average compared with the *WEO*

2000 projection of 1.4%. The Russian outlook for the TPES mix also includes a much greater share for nuclear power (as well as coal), while the IEA's outlook foresees continued growth in the share of natural gas.

In the *WEO 2000*, the IEA estimates Russian CO_2 emissions in 2010 at about 690 Mt below 1990, not taking into account the possible effect of additional domestic abatement measures. Assuming a price of \$32/tonne of CO_2 in constant 2000 dollars, emissions would be reduced to 1,166 mln tonnes below 1990 levels, which would mean potential revenues to Russia from emissions trading would be on the order of \$37 billion.[171] To make emissions trading and Joint Implementation projects possible, however, domestic management of GHG emissions is critically important and clearly needs further development. This should include an efficient mechanism for controlling emissions from various sources, a reliable monitoring and reporting system and an efficient process to manage this new market. The system of charges for emissions from industrial sources could be modified and adapted for monitoring and reporting GHG emissions. National and regional administrations do not now have special offices for dealing with climate-change issues. In the future, however, regional energy-efficiency centres and environmental funds should be given resources to develop regional programmes and policies on GHG emissions.

►►► ***Domestic management of GHG emissions is of the utmost importance.*** *For emissions trading and joint implementation projects to be possible, an efficient domestic mechanism for controlling emissions from various sources and a reliable monitoring and reporting system are essential*

Nine Joint Implementation projects involving Russia have been officially approved so far. Four are with the United States – two reforestation projects, a project to reduce methane emissions from Gazprom's pipelines and a district-heating network/energy-efficiency project. These projects are at various stages of development. The Netherlands is taking part in a horticulture and sanitary-landfill project. Rurhgas has initiated jointly with Gazprom a project to improve long-distance gas transmission. In April 1998, Japan and Russia agreed that Japanese firms would begin feasibility studies on 20 Joint Implementation projects to improve energy efficiency at Russian electricity plants and reduce GHG emissions. Unfortunately, the slow development in this area so far does not bode well for the Joint Implementation mechanism's future ability to stimulate major investments in energy efficiency.

Much uncertainty surrounds CO_2 projections for 2008-2012. Emission levels depend on many factors. Difficulties arise in assessing the scale of domestic abatement actions, especially in economies in transition, where the success of these initiatives will depend largely on effective implementation of price and economic reforms. Growth rates of CO_2 emissions depend on GDP growth rates. A sensitivity analysis presented in WEO 2000 based on variations of one percentage point per year above and below the reference scenario's growth assumption, demonstrates the effect of higher and lower growth on

171. The estimated \$32/tonne of CO_2 equivalent assumes the participation of all the Protocol's Annex B countries in emissions trading. This price therefore does not take into consideration the impact of the US withdrawal. Projections of the carbon price without US participation indicates a 50 to 95% decline in international price, assuming a perfectly competitive market. For more information see *International Emission Trading: from Concept to Reality*, IEA (2001), Paris, 2001.

energy demand and carbon emissions in 2020. As shown in Table 10.6, in the high-growth case, Russian TPES would increase by 23% and CO_2 emissions by 24% over projected levels in 2020. Relative to 1990, TPES in the high-growth case would be about 11% higher and carbon emissions 7% higher in 2020.

Table 10.6 GDP-CO_2 Sensitivity Analysis (2000 to 2020)

	Low Growth	2020 Reference Case	High Growth
GDP (billion US$)	– 20%	1,335	+25%
TPES (Mtoe)	– 19%	802	+23%
CO_2 (Mt)	– 20%	2,041	+24%

Source: "World Energy Outlook", IEA (2000), Paris.

In the event of high growth, therefore, the potential supply of tradable emissions would be limited. To guard against the possibility of over-trading emissions if GDP growth rates exceed forecast levels, emission-trading caps can be imposed. Regardless of possible scenarios that would decrease tradable emissions, the Russian Federation, under its current climate-change commitments, clearly has the opportunity to benefit from participation in emission trading. Its own studies reveal a large potential for energy-related CO_2-emission reductions through efficiency improvements, which could lead to further reductions and to more trading. The existence of an international system, however, does not guarantee the achievement of efficiency gains on Russian territory. Domestic policy must assure that the incentives set at international levels reach the appropriate local decision-makers.

►►► ***Russia's role in international climate-change policy requires a strong domestic commitment****. Russia can gain from participation in international climate-change policy, given its currently low level of GHG emissions and its potential for further reductions through energy-efficiency improvements. To realise this potential, incentives set at international levels will have to be attractive to those making decisions at the grass-root level.*

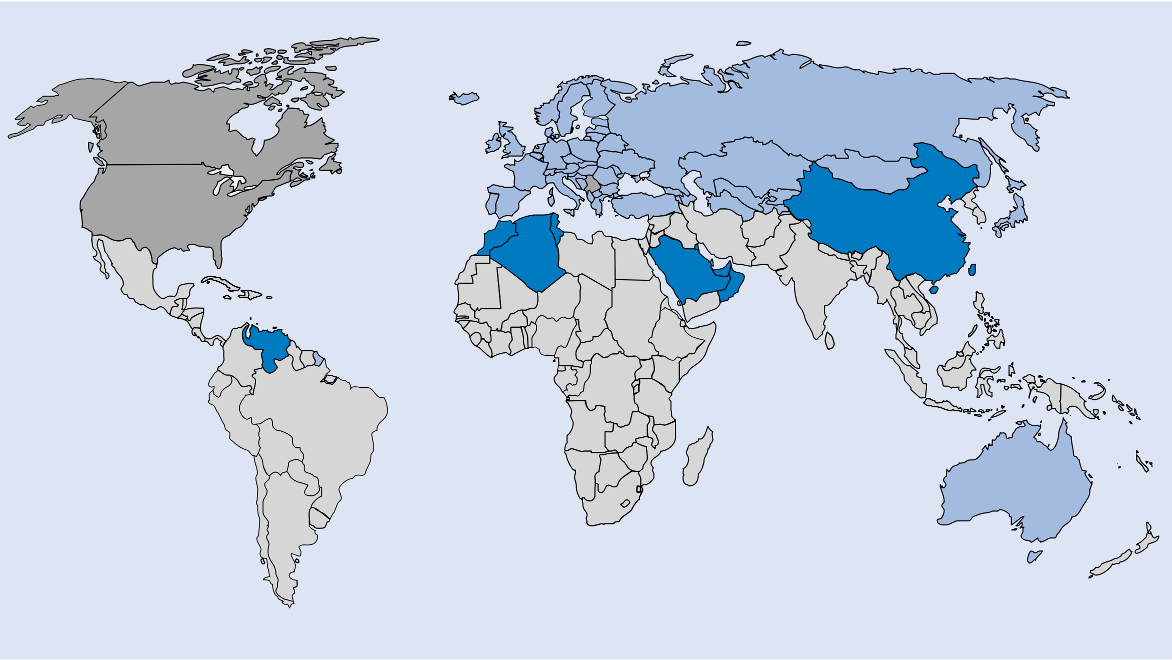
ANNEX A

THE ENERGY CHARTER TREATY

The Energy Charter Treaty ("the Treaty") has its roots in the "European Energy Charter" that was signed by 53 countries in The Hague in December 1991, including the EU, the United States, the central and eastern European states and the member states of the Commonwealth of Independent States, Australia and Japan. It represented a political commitment to cooperation in the energy sector, based on the principles of open energy markets, non-discrimination between participants, respect for state sovereignty over natural resources, and recognition of the importance of environmentally sound and energy-efficient policies. The Energy Charter Treaty was signed in Lisbon on 17 December 1994, and entered into force on 16 April 1998. As of today 45 countries have ratified it, including all European countries and all CIS countries, except Russia and Belarus. These two countries apply the Treaty provisionally. As concerns Russia, the ratification process is still pending in the State *Duma.* The Treaty is the first economic agreement uniting the newly independent states of the former Soviet Union, including the Russian Federation, Azerbaijan, Kazakhstan and Turkmenistan, the central and eastern European states and the majority of the members of the Organization for Economic Co-operation and Development. The objective of the Energy Charter process is to further the complimentary relationship in energy matters between the newly independent states of the former Soviet Union, the countries of central and Eastern Europe and the West. The major complementary relationship in energy matters between the signatories of the European Energy Charter is well documented. Theoretically, the eastern constituency of the Energy Charter process together with Norway and the United Kingdom may cover up to 50% of the net energy imports of the western part of the constituency. Observer states include some Southern Mediterranean countries (Algeria, Morocco, Tunisia) and major oil producing countries from the Middle East (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates) as well as the People's Republic of China. International organisations with observer status are the: Baltic Sea Regional Energy Cooperation (BASREC), Black Sea Economic Cooperation (BSEC), European Bank for Reconstruction and Development (EBRD), European Investment Bank (EIB), International Atomic Energy Agency (IAEA), International Energy Agency (IEA), OECD, UN-ECE and the World Bank.

The Energy Charter Conference is the governing body of the Treaty. The Energy Charter Secretariat ("the Secretariat"), located in Brussels, supports the work of the Energy Charter Conference. The detailed work is carried out by delegations from the signatory states in working groups established by the Charter Conference and mandated in accordance with the provisions of the Treaty.

Figure 26 Energy Charter Treaty Signatories and Observers, as of 1 January 2002



Signatories of The Energy Charter Treaty of 1994

Observers, Signatories of The European Energy Charter of 1991

Observers

The main energy issues addressed in the Treaty are: transit, investment protection, trade and energy efficiency and related environmental aspects. Dispute settlement is an important feature of the Treaty.

The Russian Federation applies the Treaty provisionally. However, the ratification process is currently progressing in the State *Duma* of the Russian Federation. It is of relevance to note that all the member states of the Commonwealth of Independent States ("CIS") have ratified the Treaty, with the exception of the Russian Federation and Belarus[172]. Belarus also applies the Treaty provisionally. Consequently, all the major transit states from a Russian perspective are either contracting parties to the Treaty or apply the Treaty provisionally.

Transit Provisions and Related Relevant Provisions of the Energy Charter Treaty

Article 2 of the Treaty lays down as its purpose the establishment of a legal framework in order to promote long-term co-operation in the energy field, based on complementarities and mutual benefits between the contracting parties of the Treaty.

Article 7 of the Treaty deals specifically with the issue of energy transit. Transit is defined as the movement of crude oil, oil products, natural gas or electricity from one contracting party of the Treaty through the territory of another contracting party, destined for the territory of a third contracting party. Energy transport facilities are defined as such transportation grids, which are used to transport crude oil, oil products, natural gas or electricity.

172. For the sake of easier reading, the following text talks about "contracting parties" of the ECT as such without distinguishing between contracting parties and signatories.

The major transit obligation of contracting parties, including Russia and her neighbouring transit states under the Treaty is to facilitate transit based on the principle of freedom of transit without distinction as to the origin, destination or ownership of the energy and without discrimination as to pricing on the basis of such distinctions. Contracting parties shall encourage co-operation in the modernizing, interconnection, development and operation of energy transport facilities, including mitigation of the effects of interruption in the supply of energy.

Contracting parties shall make their provisions relating to the transport of energy such that energy in transit shall be treated no less favourably than their transportation provisions treat energy produced domestically and exported or energy imported.

The contracting parties of the Treaty shall not place obstacles in the way of new energy transport facilities being constructed. However, if the security or the efficiency of the existing energy transport facilities is endangered, including the security of supply, construction or modification for new or additional transit may not be granted permit. In addition, the established flows of energy in transit shall be secured.

Article 7(6) of the Treaty obliges contracting parties, including Russia and her neighbouring transit states not to interrupt or reduce the existing flow of energy in transit in the event of a dispute over such transit prior to the conclusion of a set of dispute resolution procedures laid down in Article 7(7) of the Treaty. These conciliation procedures are described below.

Unless otherwise explicitly stated all obligations of the Treaty are between the states signing the Treaty. However, the contracting parties shall not encourage any state enterprise or any entity, which it establishes or maintains, which is granted exclusive or special privileges, to conduct its activities in a manner inconsistent with the obligations of the state under the Treaty. If a contracting party establishes or maintains an entity and entrusts the entity with regulatory, administrative or other governmental authority, such entity shall conduct its authority in a manner consistent with the obligations of the contracting party under the Treaty. In addition, each contracting party is responsible for the observance of the provisions of the Treaty by regional or local governments or authorities.

There is a general set of exceptions to the obligations laid down in Article 7 of the Treaty, such as no obligation may endanger human, animal or plant life or health. Conditions of short supply exempt from performance of the obligations, as do the protection of the essential security interests or the maintenance of public order of a contracting party.

The contracting parties of the Treaty are currently negotiating an Energy Charter Protocol on Transit to complement, extend and amplify the existing transit provisions of the Treaty.

WTO/GATT Provisions Applicable under the Treaty

The World Trade Organization ("WTO") rules that apply under the Treaty may be summarized as follows: Most of the substantive provisions of WTO's Multilateral Agreements on Trade in Goods[173] are applicable to all Treaty Amendment participants. The other two main pillars of the WTO system, the General Agreement on Trade in

173. Annex 1A to the Agreement Establishing the WTO.

Services (GATS)[174] and the Agreement on Trade-Related Aspects of Intellectual Property Rights (TRIPS)[175] were left out from the applicable WTO rules under the Treaty. It is, however, worth noting that the definition of "Economic Activity in the Energy Sector" includes all energy services,[176] and a commitment to provide effective protection of intellectual property rights following the highest international standards was declared.[177] Institutional provisions of WTO are replaced with appropriate references to the Energy Charter Conference and the Secretariat.

The dispute settlement system of the WTO (DSU), which cannot be used for non-WTO members, is replaced in Annex D by a panel based dispute resolution mechanism which is inspired by the DSU but less heavy (no standing appellate body is foreseen).

The plurilateral Agreements under the WTO, such as the Agreement on Government Procurement, have not been taken over.

The WTO Agreements, which lack relevance, do not apply (Agreement on Agriculture, Agreement on the Application of Sanitary and Phytosanitary Measures and Agreement on Textiles and Clothing). The Agreement on Trade-Related Investment Measures does not apply either. The content of this Agreement is instead reflected in Article 5 and linked to dispute settlement under the Treaty.

The main substantive difference between the trade regime of the Treaty and that of the WTO is that no tariff binding regime applies under the former. Contracting parties, such as Russia, to the Treaty have only undertaken a soft-law best-endeavours commitment not to raise their customs duties above applied rates.

The following description focuses on the WTO provisions most relevant for transit of energy as the question of energy transit is deemed to be of particular importance to the Russian energy strategy.

The understanding of the terms exportation, importation and transit under the WTO provisions render such terms mutually exclusive.

Article V of the GATT 1994 comprises a self-contained set of provisions addressing transit. The rules may be read in isolation, since the rest of the WTO provisions are addressing exportation and importation. An interpretation may be that since by design the provisions on transit can be identified as different from the exportation/importation provisions and since the intention is to facilitate transit through the exemption, inter alia, from customs duties, all the provisions on transit under the WTO Agreement must be understood to convey a system with more favourable conditions than the exportation/importation conditions, since said export/import conditions would be the alternative treatment if no *lex specialis* existed on transit in Article V of the GATT 1994.

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174. Annex 1B to the Agreement Establishing the WTO.
175. Annex 1C to the Agreement Establishing the WTO.
176. Article 1(5) of the ECT, Final Act of the European Energy Charter Conference, Understandings, 5. With respect to Article 1(12).
177. Final Act of the International Conference and Decision by the Energy Charter Conference in Respect of the Amendment to the Trade-Related Provisions of the Treaty, Joint Declaration on Trade-Related Intellectual Property Rights.

For completeness, both the key provisions on exportation and importation of energy and the provisions on transit of energy are outlined below.

Any advantage, favour, privilege or immunity related to customs duties and charges of any kind on importation or exportation, related to the international transfer of payments for such importation or exportation, related to the method of levying such customs duties and charges of any kind, and with respect to all rules and formalities related to exportation or importation granted by a contracting party to any energy carrier originating in or destined for any other country shall be accorded immediately and unconditionally to the like energy carrier originating in or destined for the territories of all other contracting parties. This principle is commonly referred to as general most favoured nation treatment.

Furthermore the contracting parties recognize that the internal taxes and other internal charges, laws, regulations and requirements affecting the internal sale of energy including internal quantitative regulations regarding mixture, processing or the use of energy in specific proportions shall not be applied to imported or domestic energy carriers so as to afford protection to domestic production of such energy.

Energy imported from any other contracting party shall not be subject to internal taxes or other internal charges of any kind in excess of those applied to like domestic energy carriers.

Energy imported from any other contracting party shall be accorded treatment no less favourable than the treatment accorded to like energy carriers of national origin in respect of all laws, regulations and requirements affecting the sale of such energy. This principle is commonly referred to as national treatment. The transportation charge may differ from the domestic transportation charge based exclusively on the economic operation of the means of transportation and not on the nationality of the energy.

The contracting parties shall not have internal quantitative regulations, which require that part of the energy supply must be from domestic sources. No quantitative regulation shall allocate the proportion of energy among external sources of supply.

All fees and charges of whatever character, other than import and export duties and other than taxes, imposed by a contracting party on importation or exportation of energy shall be limited in amount to the approximate cost of services rendered and shall not represent an indirect protection to domestic products or a taxation of imports or exports for fiscal purposes.

Under the WTO provisions, transit is defined as the portion of a complete journey beginning and terminating beyond the frontier of the contracting party across whose territory the traffic passes. The most convenient route for international transit shall be used, without distinction as to place of origin, departure, entry, exit or destination or ownership of the energy or ownership of the energy transport facilities used for transit. No unnecessary delays or restrictions shall be imposed on the transit. Transit shall be exempt from customs duties and from all transit duties or other charges, except for transportation charges or those charges commensurate with administrative expenses entailed or cost of services rendered. All charges and regulations shall be reasonable when addressing transit of energy. All charges, regulations and formalities accorded to the transit of energy between contracting parties shall be no less favourable than the treatment accorded to transit of energy to or from any third country. Regarding transportation charges, a comparison is made between like products being transported on the same route under like conditions. When determining customs clearance procedures, each contracting party shall ignore the fact that some part of the energy flow may have been in transit through the territory of other contracting parties before entering its territory for customs clearance.

No restrictions other than duties, taxes or other charges shall be instituted or maintained by the Russian Federation or her neighbouring states on the importation of energy of the territory of any other contracting party or on the exportation or sale of any energy destined for the territory of any other contracting party. The only exception may be to prevent or relieve domestic critical shortages of energy, or the application of standards for the marketing of commodities in international trade.

The WTO provisions apply only to governmental measures. By measures are understood any measure by a contracting party in the form of a law, regulation, rule, procedure, decision, administrative action or any other form. In order to avoid that the contracting parties circumvent their obligations under the Treaty, obligations are imposed on actions taken by so-called state trading enterprises. If a contracting party establishes or maintains a state enterprise or grants any enterprise exclusive or special privileges, such enterprise shall for export, import or transit of energy act in a manner consistent with the general principles of non-discriminatory treatment laid down in the WTO Agreement for governmental measures. State trading enterprises or enterprises, which enjoy exclusive or special privileges, shall solely act in accordance with commercial considerations and shall afford the enterprises of other contracting parties the opportunity to compete. No contracting party shall prevent any enterprise under its jurisdiction from acting in accordance with the above principles.

As is the case for the transit provisions under Article 7 of the Treaty, there are exceptions to the obligations on exportation, importation and transit under the WTO Agreement applicable under the Treaty.

All exceptions must fulfill the requirement that such exception measures are not applied arbitrarily or unjustifiably discriminate between states where the same conditions prevail. Such exception measures shall not be a disguised restriction on international trade.

Investment

Based on the model of bilateral investment treaties, the Treaty grants a number of fundamental rights to foreign investors with regard to their investment in the host country. Russian investors active outside the territory of Russia are protected against the most important political risks, such as discrimination, expropriation and nationalisation, breach of individual investment contracts, damages due to war and similar events, and unjustified restrictions on the transfer of funds. Russia offers the same protection to investors of other contracting parties active on Russian territory.

According to Article 1(6) of the Treaty, "investment" means every kind of asset, owned or controlled directly or indirectly by an investor.

According to Article 10 (1), each contracting party, such as Russia, shall encourage and create stable, equitable, favourable and transparent conditions for investors to make investments. Such conditions include a commitment to accord fair and equitable treatment to foreign investors, and the most constant protection and security of the investment of such investors.

Article 10 (7) obliges host countries to accord to investments of investors of other contracting parties the better of national treatment or most-favoured-nation treatment. Decision Nr.2 concerning Article 10 (7) grants the Russian Federation the right to require for investors to obtain legislative approval for the leasing of federally owned land. In doing so, Russia has to respect the principle of most-favoured nation treatment.

Article 10 (2) of the Treaty includes a non-legally binding "best efforts" clause to also grant foreign investors non-discriminatory treatment concerning the making of their investments i.e. their establishment in the host country, e.g. Russian investment in Ukraine. Article 10 (4) provides for future negotiations on the extension of the non-discrimination principle in a legally binding manner to the pre-establishment phase. These negotiations on a so-called "Supplementary Treaty" began in 1995 and were suspended in 1998. Although negotiators have come close to a final agreement, a number of political issues still need to be resolved before an agreement is reached.

According to Article 13, an expropriation has to be in the public interest, non-discriminatory, carried out under due process of law and accompanied by payment of prompt, adequate and effective compensation. Compensation shall amount to the fair market value of the investment at the time immediately before the expropriation, or impending expropriation, became known in such a way as to affect the value of the investment. The investor may request compensation in a freely convertible currency, and it shall include interest at a commercial rate until the date of the payment.

Article 12 (1) provides that in the event of war or civil disturbance in the area of a contracting party, the host government shall accord to foreign investors who suffer a loss, non-discriminatory treatment. Article 12 (2) establishes an absolute obligation to compensate foreign investors if they suffer a loss resulting from the requisitioning of the investment, or unwarranted destruction of the investment by the authorities or forces of the host government.

Article 14 guarantees the freedom of transfer with respect to investments. Transfers shall be made at the market rate of exchange in a freely convertible currency. The CIS countries may, as concerns transfers among themselves, conclude agreements that transfer of payments shall be made in the currencies of such parties, provided that such agreements ensure that investors of other parties to the Treaty are accorded the better of national and most favoured nation treatment (Article 14 (5)).

In addition, Decision Nr. 3 concerning Article 14 grants CIS countries the right to apply restrictions on the movement of capital by their *own* investors. However, such restrictions may not impair the rights granted to foreign investors with respect to their investments. Decision Nr. 3 required contracting parties wishing to apply this kind of restriction to make a notification to the Secretariat no later than 1 July 1995. Within this timeframe, only the Russian Federation made such a notification.

According to Article 10 (1), last sentence, each contracting party, such as any member state of the CIS, shall observe any obligations it has entered into with an investor or an investment of any other contracting party. This provision covers any contract that a host country has concluded with a subsidiary of the foreign investor in the host country, or a contract between the host country and the parent company of the subsidiary.

Article 11 permits foreign investors to employ key personnel of their choice, regardless of nationality, so long as such personnel have the required work and residence permits.

Energy Efficiency and Related Environmental Aspects

The Treaty (Art 19 – Environmental Aspects) requires that each contracting party strive to minimise, in an economically efficient manner, harmful environmental impacts resulting from all operations within the energy cycle in its area. Art 19 of the Treaty also requires contracting parties to promote market oriented price formation and reflection of environmental costs. Basic principles with strong influence on the energy efficient behaviour in an economy, such as regards price formation, liberal trading relations, public awareness and international co-operation, are in this way already anchored within the Treaty.

The Energy Charter Protocol on Energy Efficiency and Related Environmental Aspects (PEEREA) was negotiated, opened for signature and entered into force at the same time with the Treaty – on 16 April 1998. PEEREA provides a mechanism for international co-operation and exchange of experience and ideas between less developed countries and countries with twenty years or more experience in this area.

The Protocol is structured in five parts including basic policy principles, strategies, international co-operation and legal arrangements. In particular, the Protocol: Defines policy *principles* for the promotion of energy efficiency; Provides a *framework* for the development of co-operative and coordinated action; Provides *guidance* on the development of energy efficiency programmes; Indicates areas of possible *co-operation.*

PEEREA promotes the principles of "full-cost", "cost-effectiveness", and "sustainable development" as the appropriate platform for the development of energy efficiency policies and greater international and institutional co-operation. PEEREA requires Contracting Parties to encourage: implementation of innovative approaches for financing energy efficiency, introduction of fiscal and financial incentives for the penetration of energy efficient technologies, commercial trade and cooperation in the area of energy efficient and environmental sound technologies and action of the private sector.

PEEREA expressly stipulates that governments shall: Formulate energy efficiency aims and strategies (Article 5); Establish energy efficiency policies (Article 3.2); Develop, implement, and update domestic energy efficiency programmes (Article 8.1); Create the necessary legal (Article 3.2), regulatory (Article 3.2) and institutional (Article 8.3) environment; Cooperate/assist internationally (Article 3.1).

In every of these areas PEEREA defines detailed measures and instruments which can be used for achieving the policy aims. Such instruments and programmes should be suited to the national circumstances of each country.

A special Working Group serves the process of implementation of PEEREA. The Working Group on Energy Efficiency and Environmental Related Aspects meets regularly, also to address priorities and to discuss possible plans for action. The Working Group has developed its activities into two areas: a) reviewing progress in implementing the PEEREA and in improving energy efficiency and b) developing activities which support dialogue between member countries and facilitate the implementation of the Protocol.

Activities supporting dialogue and facilitating implementation of the Protocol include: a brochure on Developing an Energy Efficiency Strategy, an Application Manual on Financing Energy Efficiency, a report on Fiscal and Taxation Policies for improving Energy Efficiency, a report on Effects of Market Liberalisation on Energy Efficiency and a report on the Role and Evolution of Energy Efficiency Institutions.

The review process relies on two major complementary components: regular monitoring based on a review format and in-depth energy efficiency reviews. Regular reviews serve mainly the purpose of monitoring, and they support reporting also on implementation of commitments made at Aarhus Environmental Ministers Conference in 1998. In-depth energy efficiency reviews are made on a peer basis and include the mission of representatives of 3-4 countries to the host country. The first in-depth energy efficiency review took place in 1999 in the Slovak Republic. Lithuania, Poland, Hungary and Bulgaria have subsequently hosted in-depth energy efficiency reviews in 2000 and 2001. The Energy Charter Conference has endorsed the in-depth energy efficiency reviews, which include specific recommendations to the respective national governments concerning possible improvements to their national energy efficiency policies and programmes.

Dispute Settlement

The Treaty includes a well-developed international dispute resolution mechanism. By providing an alternative means of dispute resolution before international tribunals, the Treaty increases confidence of energy investors and traders in the legal regime, and contributes to further promoting investment and trade flows between members.

The Treaty recognises two basic forms of binding dispute settlement: State-state arbitration for basically all disputes arising under the Treaty (Article 27); and investor-state arbitration for investment disputes (Article 26).

Separate provisions have been developed for the resolution of disputes in the area of trade (Article 29, Annex D), transit (Article 7), competition (Article 6) and environment (Article 19).

Investor-to-State disputes: Based on the model of bilateral investment agreements, Article 26 grants foreign investors the right to sue the host country in case of an alleged breach of the investment-related obligations of a host State. The investor can chose between several international arbitration mechanisms, including ICSID, the

UNCITRAL arbitration rules or the Arbitration Institute of the Stockholm Chamber of Commerce. Prior to arbitration, consultations between the disputing parties shall be held. The award is binding, final and enforceable.

State-to-State disputes: According to Article 27 (2), inter-state disputes have to be submitted to an ad hoc tribunal. The UNCITRAL rules shall apply, unless there is an agreement to the contrary between the contracting parties. The arbitral award shall be final and binding. Unless the parties to the dispute agree otherwise, the tribunal shall sit in The Hague, and use the premises and facilities of the Permanent Court of Arbitration.

Article 29 of the Treaty provides for a trade dispute resolution mechanism (Annex D) that is based on the GATT/WTO panel model. It applies only in cases where at least one of the disputing parties is not a member of the WTO. Disputes of an intra-GATT/WTO nature are to be resolved in the appropriate WTO fora. This approach avoids a possible parallelism of dispute settlement procedures concerning the same dispute ("forum shopping").

In general, the trade dispute resolution mechanism of the Treaty is lighter, less detailed and simpler than that developed in the WTO. In particular, it does not apply to any dispute that arises under an agreement as described in Article XXIV of the GATT (relating to free trade area or customs union) or under an agreement among States that were constituent parts of the former Soviet Union (Article 29 (2b)).

Article 7 (7) establishes a conciliation mechanism concerning transit disputes. A contracting party being party to the dispute may notify the dispute to the Secretary-General of the Secretariat who shall consult with the interested parties and appoint a conciliator within 30 days. If the conciliator fails to secure an agreement within ninety days, s/he shall recommend a resolution or a procedure to achieve such resolution, and shall decide the interim tariffs and other terms and conditions to be observed until the dispute is resolved.

Article 7(6) provides that the transit state shall not, in the event of a dispute over "any matter arising from that transit", interrupt or reduce, or permit or require any entity to interrupt or reduce, the existing flow of energy materials and products prior to the conclusion of the conciliation mechanism.

Article 6 (5) establishes a mutual information and consultation mechanism in respect of the interpretation and application of national competition laws. The provision reflects the fact that the Treaty does not establish a common competition regime between contracting parties.

According to Article 19 (2), the Charter Conference shall, at the request of one or more contracting parties, review disputes concerning the application or interpretation of the environment-related obligations of the Treaty, aiming at a solution. The Charter Conference may make recommendations to the parties in dispute on how to settle the case.

ANNEX B

ENERGY BALANCES AND KEY STATISTICAL DATA

In Mtoe

SUPPLY

		1990*	1991*	1992	1993	1994	1995	1996	1997	1998	1999
TOTAL PRODUCTION		1270.0	1194.2	1118.7	1045.4	980.1	954.0	947.4	921.7	928.4	950.6
Coal[1]		179.6	155.6	143.9	135.1	123.3	117.0	112.1	106.6	101.6	115.3
Oil		516.0	462.1	398.8	353.3	317.3	306.6	301.0	305.4	302.9	304.8
Gas		516.7	519.0	517.2	498.9	490.1	480.4	485.4	460.8	477.0	477.1
Comb. renewable & waste[2]		12.2	11.5	12.4	11.8	8.4	8.5	6.9	6.8	5.4	7.4
Nuclear		31.3	31.6	31.5	31.4	25.9	26.2	28.8	28.6	27.8	32.1
Hydro		14.3	14.4	14.8	14.9	15.0	15.1	13.2	13.5	13.6	13.8
Geothermal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar / wind / other[3]		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL NET IMPORTS[4]		– 409.5	– 344.8	– 328.7	– 292.0	– 313.1	– 314.0	– 333.4	– 338.9	– 345.6	– 350.6
Coal[1]	Exports	35.1	21.5	22.0	15.4	14.0	15.7	14.7	13.9	14.4	17.3
	Imports	33.5	25.7	20.6	16.0	15.4	12.4	10.9	11.2	11.8	8.8
	Net Imports	– 1.6	4.2	– 1.4	0.6	1.4	– 3.3	– 3.8	– 2.7	– 2.6	– 8.5
Oil	Exports	288.0	229.2	186.3	171.3	171.6	169.5	181.6	185.3	189.1	183.8
	Imports	26.1	24.6	12.5	13.1	6.1	11.6	9.5	9.8	9.5	5.5
	Net Imports	– 262.0	– 204.6	– 173.8	– 158.2	– 165.4	– 157.9	– 172.1	– 175.5	– 179.6	– 178.4
Gas	Exports	201.7	154.5	157.7	138.1	148.9	154.0	158.7	162.2	164.3	165.8
	Imports	56.4	11.1	5.6	5.3	1.6	2.9	2.8	3.6	2.4	3.3
	Net Imports	– 145.2	– 143.4	– 152.1	– 132.8	– 147.3	– 151.1	– 155.9	– 158.6	– 161.8	– 162.5
Electricity	Exports	3.7	4.1	3.8	3.7	3.8	3.3	2.7	2.3	2.3	1.9
	Imports	3.0	3.0	2.4	2.1	2.0	1.6	1.1	0.6	0.7	0.7
	Net Imports	– 0.7	– 1.0	– 1.4	– 1.6	– 1.8	– 1.7	– 1.7	– 1.7	– 1.5	– 1.2
TOTAL STOCK CHANGES		9.5	– 12.5	– 15.2	– 7.2	– 15.4	– 11.6	2.7	12.4	– 1.4	2.9
TOTAL SUPPLY (TPES)		868.1	836.9	774.8	746.3	651.5	628.4	616.6	595.1	581.4	603.0
Coal[1]		181.9	149.3	132.2	133.4	125.4	116.7	118.9	106.7	100.7	109.1
Oil		261.8	257.5	221.0	200.4	150.7	147.0	132.2	130.0	124.1	127.2
Gas		367.3	373.6	364.2	355.9	327.6	316.5	318.2	311.5	310.9	314.5
Comb. renewable & waste[2]		12.2	11.5	12.4	11.8	8.7	8.5	6.9	6.5	5.8	7.5
Nuclear		31.3	31.6	31.5	31.4	25.9	26.2	28.8	28.6	27.8	32.1
Hydro		14.3	14.4	14.8	14.9	15.0	15.1	13.2	13.5	13.6	13.8
Geothermal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar / wind / other[3]		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity trade[5]		– 0.7	– 1.0	– 1.4	– 1.6	– 1.8	– 1.7	– 1.7	– 1.7	– 1.5	– 1.2
Shares (%)											
Coal		20.95	17.84	17.07	17.88	19.25	18.57	19.28	17.93	17.32	18.09
Oil		30.16	30.77	28.53	26.85	23.13	23.39	21.45	21.85	21.35	21.09
Gas		42.31	44.64	47.00	47.69	50.28	50.37	51.61	52.34	53.47	52.16
Comb. renewable & waste		1.40	1.37	1.61	1.59	1.33	1.36	1.12	1.10	1.00	1.25
Nuclear		3.61	3.78	4.07	4.21	3.97	4.18	4.67	4.81	4.78	5.33
Hydro		1.64	1.72	1.91	2.00	2.31	2.40	2.14	2.26	2.34	2.29
Geothermal		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar / wind / other		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity trade		– 0.08	– 0.12	– 0.18	– 0.22	– 0.27	– 0.27	– 0.27	– 0.28	– 0.27	– 0.20

In Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1990*	1991*	1992	1993	1994	1995	1996	1997	1998	1999
TFC	656.8	634.6	586.6	565.1	485.6	464.9	419.2	401.7	394.1	410.4
Coal[1]	54.9	48.6	29.6	30.4	24.0	27.7	22.6	18.3	17.8	19.6
Oil	155.3	161.0	140.2	119.4	92.4	89.6	84.3	83.9	76.3	85.2
Gas	143.1	139.9	135.9	141.8	124.4	118.1	114.1	108.7	111.8	114.5
Comb. renewable & waste[2]	8.1	7.6	8.0	8.3	5.1	4.4	3.9	3.5	2.8	3.8
Electricity	71.1	69.8	65.0	60.7	54.6	53.2	51.7	50.7	49.8	51.0
Heat	224.4	207.8	207.8	204.5	185.1	171.9	142.6	136.5	135.6	136.3
Shares (%)										
Coal	8.35	7.65	5.05	5.37	4.94	5.95	5.40	4.57	4.52	4.78
Oil	23.64	25.37	23.90	21.14	19.03	19.26	20.10	20.89	19.37	20.77
Gas	21.78	22.04	23.17	25.09	25.61	25.41	27.21	27.07	28.38	27.91
Comb. renewable & waste	1.23	1.21	1.37	1.47	1.05	0.96	0.93	0.88	0.70	0.91
Electricity	10.82	11.00	11.09	10.74	11.25	11.44	12.33	12.63	12.62	12.42
Heat	34.17	32.74	35.42	36.18	38.12	36.98	34.02	33.98	34.40	33.20
TOTAL INDUSTRY[6]	139.2	150.8	138.7	224.7	177.1	175.1	150.3	144.6	137.2	145.1
Coal[1]	15.7	14.2	13.4	13.6	12.1	16.5	14.4	10.5	10.5	10.7
Oil	30.5	43.1	36.2	31.7	19.9	18.0	16.3	17.5	17.4	20.5
Gas	51.6	53.8	52.2	48.2	38.0	39.7	37.7	39.0	35.6	37.6
Comb. renewable & waste[2]	0.0	0.0	0.9	0.5	0.4	0.5	0.4	0.4	0.5	0.7
Electricity	41.4	39.7	36.0	32.4	27.4	27.0	25.3	25.1	24.4	25.5
Heat	0.0	0.0	0.0	98.3	79.4	73.3	56.1	52.1	48.8	50.1
Shares (%)										
Coal	11.31	9.45	9.66	6.06	6.83	9.41	9.61	7.29	7.66	7.37
Oil	21.89	28.60	26.10	14.11	11.21	10.28	10.87	12.09	12.66	14.15
Gas	37.06	35.66	37.61	21.45	21.44	22.70	25.08	26.94	25.95	25.93
Comb. renewable & waste	0.00	0.00	0.63	0.22	0.22	0.31	0.26	0.27	0.38	0.49
Electricity	29.75	26.29	25.99	14.41	15.46	15.43	16.83	17.35	17.75	17.54
Heat	0.00	0.00	0.00	43.76	44.83	41.87	37.34	36.07	35.59	34.52
TRANSPORT[7]	126.54	122.70	117.14	99.83	88.30	81.85	78.14	72.09	81.74	82.41
TOTAL OTHER SECTOR[8]	391.1	361.1	330.7	240.5	220.2	207.9	190.8	185.0	175.2	182.8
Coal[1]	39.1	34.3	16.2	16.8	11.9	11.2	8.2	7.8	7.3	8.9
Oil	41.2	37.1	28.3	27.3	21.7	24.7	23.9	23.9	13.3	18.2
Gas	57.4	52.4	49.8	60.8	54.9	49.0	47.8	45.6	45.3	46.2
Comb. renewable & waste[2]	8.1	7.6	7.2	7.8	4.7	3.9	3.5	3.1	2.2	3.0
Electricity	20.7	21.8	21.5	21.7	21.4	20.6	20.8	20.2	20.2	20.3
Heat	224.4	207.8	207.8	106.1	105.7	98.6	86.5	84.3	86.8	86.1
Shares (%)										
Coal	10.00	9.51	4.91	6.97	5.41	5.38	4.30	4.22	4.18	4.89
Oil	10.54	10.28	8.55	11.36	9.84	11.86	12.54	12.94	7.60	9.96
Gas	14.69	14.51	15.05	25.27	24.92	23.57	25.06	24.65	25.86	25.26
Comb. renewable & waste	2.07	2.12	2.16	3.26	2.14	1.88	1.84	1.70	1.28	1.66
Electricity	5.30	6.04	6.51	9.03	9.70	9.89	10.91	10.91	11.55	11.10
Heat	57.39	57.54	62.82	44.12	48.00	47.41	45.34	45.58	49.53	47.12

In Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1990*	1991*	1992	1993	1994	1995	1996	1997	1998	1999
HEAT AND POWER GENERATION[9]										
INPUT [Mtoe]	444.6	433.6	413.6	408.1	377.2	354.4	355.7	337.7	333.2	338.7
OUTPUT Electricity [TWh]	1082.2	1068.2	1008.5	955.7	874.9	859.0	846.2	833.2	826.2	845.3
Heat [1000 Tj]	9398.4	8700.0	8700.0	9466.6	8631.4	8052.8	6708.3	6400.2	6347.4	6332.8
Electricity output shares (%)										
Coal	14.51	14.50	15.30	15.55	18.60	18.69	19.02	18.87	19.67	19.09
Oil	11.89	11.61	9.93	8.68	8.39	7.90	6.69	6.23	6.39	4.84
Gas	47.33	46.96	45.68	44.97	41.64	41.22	43.10	42.90	41.82	42.42
Comb. renewable & waste	0.00	0.00	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.25
Nuclear	10.93	11.23	11.86	12.47	11.18	11.59	12.88	13.02	12.75	14.42
Hydro	15.33	15.69	17.04	18.14	20.00	20.42	18.12	18.79	19.18	18.99
Heat output shares (%)										
Coal	23.31	23.19	20.92	23.08	24.51	24.21	22.80	22.39	21.80	21.70
Oil	14.57	15.09	15.92	15.37	13.19	13.37	13.41	10.63	12.41	10.46
Gas	60.46	60.07	61.44	60.29	60.91	60.74	62.23	65.37	64.19	65.85
Comb. renewable & waste	1.44	1.47	1.55	1.10	1.22	1.53	1.34	1.38	1.38	1.76
Nuclear	0.21	0.18	0.17	0.16	0.18	0.16	0.22	0.22	0.22	0.24
TOTAL LOSSES of which:										
Electricity & heat generation[10]	127.1	134.0	119.1	99.8	95.8	88.3	122.7	113.3	110.5	114.8
Other transformation	40.3	17.6	19.9	18.0	10.5	15.6	14.9	12.2	15.0	17.7
Own use and losses	67.1	59.8	55.8	73.2	67.1	68.6	66.3	61.6	64.8	65.0
Statistical differences	23.3	9.0	6.6	9.8	7.6	8.9	6.6	– 6.4	3.0	4.9

INDICATORS

	1990*	1991*	1992	1993	1994	1995	1996	1997	1998	1999
GDP (billion 1995 US$)	544.0	516.5	441.5	403.2	352.5	337.9	326.4	329.4	313.2	323.2
Population (millions)	148.3	148.8	148.7	148.5	148.3	148.1	147.7	147.3	146.8	146.2
TPES/GDP[11]	1.60	1.62	1.76	1.85	1.85	1.86	1.89	1.81	1.86	1.87
Energy production/TPES	1.46	1.43	1.44	1.40	1.50	1.52	1.54	1.55	1.60	1.58
Per capita TPES[12]	5.85	5.62	5.21	5.02	4.39	4.24	4.17	4.04	3.96	4.12
Oil supply/GDP[11]	0.48	0.50	0.50	0.50	0.43	0.43	0.41	0.39	0.40	0.39
TFC/GDP[11]	1.21	1.23	1.33	1.40	1.38	1.38	1.28	1.22	1.26	1.27
Per capita TFC[12]	4.43	4.26	3.94	3.80	3.27	3.14	2.84	2.73	2.68	2.81
Energy–related CO_2 emissions (Mt CO_2)[13]	–	–	1929.3	1857.8	1637.4	1575.0	1550.7	1483.1	1439.6	1486.3
CO_2 emissions from bunkers (Mt CO_2)	–	–	44.0	37.4	31.1	29.0	27.2	27.0	25.3	26.2

** Data for 1990 and 1991 are IEA estimates based on production data received from the State Committee of Statistics of Russia (Goskomstat, 2001).*

Note: Based on the several meetings held with Russian officials in 2000 and 2001, Russian time series have been partially revised and refined. Time series now reflect the IEA methodology. The revision especially affected the sectoral breakdown of energy consumption. Due to this new methodological match the Russian coal production series have been revised downwards. Coal figures now show marketable production.

Footnotes and Sources to Energy Balances and Key Statistical Data

1. Includes lignite and peat.
2. Comprises solid biomass and animal products, gas/liquids from biomass, industrial waste and municipal waste.
3. Other includes tide, wave and ambient heat used in heat pumps.
4. Total net imports include combustible renewables and waste.
5. Total supply of electricity represents net trade. A negative number indicates that exports are greater than imports.
6. Includes non-energy use.
7. Includes less than 1% non-oil fuels.
8. Includes residential, commercial, public service and agricultural sectors.
9. Inputs to electricity generation include inputs to electricity and CHP. Output refers only to electricity generation.
10. Losses arising in the production of electricity and heat at public utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of 33% for nuclear, 10% for geothermal and 100% for hydro.
11. Toe per thousand US dollars at 1995 prices and exchange rates.
12. Toe per person.
13. "Energy related CO_2 emissions" specifically means CO_2 from the combustion of the fossil fuel components of TPES (i.e. coal and coal products, peat, crude oil and derived products and natural gas), while CO_2 emissions from the remaining components of TPES (i.e. electricity from hydro, other renewables and nuclear) are zero. Emissions from the combustion of biomass-derived fuels are not included, in accordance with the IPCC greenhouse gas inventory methodology. TPES, by definition, excludes international marine bunkers. INC-IX decided in February 1994 that emissions from international marine and aviation bunkers should not be included in national totals but should be reported separately, as far as possible. CO_2 emissions from bunkers are those quantities of fuels delivered for international marine bunkers and the emissions arising from their use. Data for deliveries of fuel to international aviation bunkers are not generally available to the IEA and, as a result, these emissions have not been deducted from the national totals.

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